

**RAPPORT D'EXPERTISE
DR REN ORANS**

**TRANSMISSION TARIFF DESIGN FOR
HYDRO-QUÉBEC TRANSÉNERGIE**

DIRECT TESTIMONY OF

DR. REN ORANS

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1. INTRODUCTION AND OVERVIEW

The purpose of my testimony is to assess the open access transmission tariff (OATT) application of Hydro-Québec when conducting transmission activities through its division Hydro-Québec TransÉnergie (HQT) in the context of the Québec's electricity market structure in place today, and relative to the generally accepted goals and industry practice of transmission pricing in North America. The assessment is based on:

- My 20-plus years of experience in the electric utility business, in which I've specialized in the areas of transmission pricing, wholesale and retail rate design, electricity market reform, and transmission and distribution (T&D) planning. My curriculum vitae, attached in the Appendix, further describes my qualifications and experience.

- My prior testimonies in Québec and other Canadian provinces on transmission rate design and related matters: (1) on behalf of the British Columbia Transmission Corporation (BCTC) in its 2004 OATT application before the British Columbia Utilities Commission (BCUC); (2) on behalf of HQT in its 2001 transmission tariff application before the Régie de l'énergie (the "Régie"); (3) on behalf of Ontario Power Generation (OPG) in Hydro One's 2000 transmission rate application before the Ontario Energy Board (OEB); (4) on behalf of BC Hydro in 1996 and 1997 in its wholesale transmission service rate applications before the BCUC; and (5)

1 on behalf of BC Hydro in its 1995 participation in the BCUC's Electricity
2 Market Restructure Review.

3 The assessment employs a two-step process. The first step evaluates HQT's
4 proposed tariff design from the perspective of traditional rate design
5 objectives: simplicity, efficiency, equity, and structural fit. Meeting the last
6 objective suitably ties a transmission design to market conditions. The
7 second step compares HQT's proposal to the industry standard transmission
8 rate designs used in North America.

9 The major conclusion from my assessment is that HQT's proposed OATT,
10 which follows the FERC *pro forma* transmission tariff, meets the generally
11 accepted goals of transmission pricing, and is consistent with industry
12 standard practice in North America. This conclusion is based on the following
13 findings to be detailed in the remainder of my testimony:

- 14 • HQT's proposed OATT is identical in structure to the current OATT,
15 effective as of January 2001. Since a competitive generation market and
16 retail access, as found in New York or New England, do not exist inside
17 Québec, HQT's tariff design continues to fit Québec's market environment
18 and is appropriate for developing unbundled transmission services and
19 the associated charges needed to promote open and comparable
20 wholesale transmission access.
- 21 • The tariff comparison shows that HQT's proposed design is consistent
22 with the OATTs of other jurisdictions that do not have an independent
23 system operator (ISO) that operates a power grid to serve a power pool
24 with a competitive generation market.
- 25 • HQT's proposed allocation of revenues between Long-Term Point-to-
26 Point (LT-PTP), Network Integration Transmission Service (NITS), and
27 Native Load Service (NLS) continues to be fair and reasonable, and
28 continues to be supported by the U.S. Federal Energy Regulatory

1 Commission's (FERC) standard revenue allocation tests detailed in
2 Section 3 below.

- 3 • The proposed rates for Short-Term Point-to-Point (ST-PTP) service
4 balance the competing objectives of (a) promoting efficient utilization of
5 transmission facilities, which keeps rates for all users as low as possible,
6 and (b) assuring that all transmission users make a fair contribution to
7 fixed costs. Moreover, the proposed method is commonly used in other
8 open access jurisdictions to increase the utilization of transmission
9 capacity.
- 10 • Over the last 4 years, HQT has experienced a reduction in Point-to-Point
11 revenues as a result of displacement of long-term with short-term service.
12 This is consistent with the development of active day-ahead and hourly
13 wholesale markets in neighboring jurisdictions over the same period.
- 14 • The growth in Native Load use of the transmission system has completely
15 offset the need to increase the Native Load service rate that would
16 otherwise have occurred due to the reduction in Point-to-Point revenues.

17 Based on these findings, I recommend that the Régie adopt HQT's proposed
18 OATT in its entirety. This recommendation is mainly supported by the fact
19 that there has been no change in the transmission objectives or market
20 design since the Régie's last adoption of HQT's existing OATT, and my own
21 market analysis.

22 The remainder of my testimony proceeds as follows. Section 2 describes
23 Québec's electricity market structure in place today and the regulatory and
24 legal constraints on the choice of a transmission rate design by HQT. Section
25 3 describes the specific design adopted by the Régie in the 2001 rate case,
26 based on the existing OATT that is now being used by HQT's customers.
27 Section 4 discusses transmission rate discount policy and describes my
28 analysis of the effectiveness of the proposed price level for hourly non-firm

1 point to point service. Section 5 briefly addresses incentive regulation in
2 connection to HQT's OATT design. Section 6 describes and evaluates a
3 common tariff design for a power grid operated by an ISO. It confirms that a
4 design like locational marginal pricing (LMP) is unsuitable for Québec in the
5 relevant time horizon of this proceeding. Section 7 compares the basic
6 structure of HQT's proposed tariff with those in other jurisdictions. The
7 section also compares the transmission rate designs of HQT and British
8 Columbia Transmission Company (BCTC), which is the jurisdiction most
9 comparable to HQT. Section 8 concludes with the recommendation that the
10 Régie should adopt HQT's proposed OATT in its entirety.

11 **2. TRANSMISSION RATE DESIGN CHOICES**

12 **2.1. Background**

13 To provide a background for HQT's design choice for its proposed
14 transmission tariff, consider Québec's electricity market structure in place
15 today. Québec's electricity sector has one major integrated electric utility,
16 Hydro-Québec (HQ), which performs generation, transmission, distribution,
17 and wholesale trading of electricity. As a division of HQ, HQT provides the
18 transmission service for (1) bringing power from HQ's power stations to the
19 retail customers of Hydro-Québec Distribution; (2) electricity trading by
20 wholesale market participants between Québec and its neighboring
21 jurisdictions; and (3) wheeling power through Québec with receipt and
22 delivery points outside HQT's grid. An OATT sets forth the terms and
23 conditions and rates under which HQT provides its transmission services to
24 its transmission customers.

25 **2.2. Objectives and constraints**

26 When considering transmission tariff design choices faced by HQT, I am
27 guided by the major objectives of a transmission tariff: (1) to collect the

1 transmission revenue requirement (TRR); (2) to be simple to implement and
2 use; (3) to offer open and comparable access to all eligible users; (4) to be
3 equitable; (5) to promote efficiency; (6) to facilitate trading; and (7) to be
4 appropriate for the market environment in which it is applied.

5 My evaluation also recognizes the regulatory/legal constraints in Québec that
6 may influence HQT's choice of a transmission rate design. The first
7 constraint is that the choice must comply with the legal framework for rate
8 setting that defines the requirement to have uniform rates, described in article
9 49 of the *Act respecting the Régie de l'énergie* (the "Act"). This limits the use
10 of geographically differentiated rates in the design of an OATT. The second
11 constraint is that the Régie has in the past refused to grant transmission
12 pricing authority to HQT (D-2002-95, p.281), thus limiting HQT's ability to
13 implement an effective discretionary rate discount.

14 Finally, my evaluation recognizes that even though FERC does not have
15 direct jurisdiction over HQT, it can encourage access to the Québec market
16 by U.S. sellers under the reciprocity requirement as a condition of its
17 authorization for HQ to trade electricity at market prices in U.S. markets.
18 Hence, HQ's continued ability to transact in U.S. markets at market prices
19 depends in part on the ability of HQT's transmission tariff to satisfy FERC's
20 criteria for open and comparable transmission access.

21 **2.3. Two design choices**

22 Based on a 2005 paper that I have coauthored,¹ there are two major
23 categories of transmission designs endorsed by FERC and widely used in
24 North America today. The first category contains designs based on the open
25 access rules and *pro forma* tariff in FERC Orders 888 and 889, which I term

¹ Lusztig, C., P. Feldberg, R. Orans and A. Olson (2005) "A survey of transmission tariffs in North America," *Energy-The International Journal*, forthcoming.

1 “open access” designs. The main goals of an open access tariff are
2 comparability of access and tariff simplicity, which the tariff achieves by
3 offering transmission service at “postage stamp” (i.e., geographically uniform)
4 rates based on average cost pricing. For the sake of clarity, I shall refer to a
5 jurisdiction that uses an “open access” design as an “open access”
6 jurisdiction.

7 The second category of designs has the primary goal of developing
8 competitive generation markets at a regional (i.e., state or provincial, not
9 federal) level, which I term “pool” designs. A pool design typically has
10 geographically differentiated rates that can vary from hour to hour. For the
11 sake of clarity, I shall refer to a jurisdiction that uses a “pool” design as a “pool
12 design” jurisdiction.

13 Although a growing number of transmission owners have adopted a pool
14 design, the *pro forma* open access tariff continues to be the most common
15 design, used in numerous jurisdictions that include Canadian transmission
16 providers such as HQT, BC Hydro, Manitoba Hydro, New Brunswick Power
17 (NBP), and SASKPOWER, as well as the majority of transmission providers in
18 the U.S.

19 The BC Hydro case is of particular interest when considering the open access
20 design for HQT. British Columbia, like Québec, is a net exporter of electricity
21 and relies on export revenue to maintain its low electricity rates. As the
22 transmission provider in BC, BCTC advocates the use of a *pro forma* OATT
23 that meets the objectives of transmission pricing.²

24 Pool designs are used in association with ISOs and RTO’s in Alberta, Ontario,
25 California, Texas, Midwest, PJM, New York, and New England. Without

² See BCTC OATT Application filed August 3rd, 2004, p18. The complete application is available at :

http://www.bctc.com/regulatory/applications/open_access_transmission_tariff.htm

1 exception, these jurisdictions have competitive generation markets, which do
2 not exist in Québec and other open access jurisdictions.

3 **2.4. Open access design for HQT**

4 An open access design follows the *pro forma* tariff in FERC's Order 888. It is
5 typically used by a vertically-integrated utility like HQ to allow transmission
6 access by third parties, while continuing to provide the network service
7 necessary to link multiple generation resources to serve loads dispersed over
8 its service territory.

9 Under the open access design, transmission customers pay transaction-
10 based fees for their use of the transmission system. The transmission
11 revenue requirement (TRR) is allocated between point-to-point (PTP) and
12 network services, based on a forecast of transmission usage by each type of
13 service. A PTP customer pays a reservation charge for reserved capacity
14 linking a point-of-receipt (POR) for power injection and a point-of-delivery
15 (POD) for power withdrawal. The charge is equal to the allocated share of
16 the TRR divided by the sum of expected transmission reservations. Once the
17 reservation is confirmed, the customer is obligated to pay for service even if
18 the reserved capacity is not used. Moreover, if a customer does not plan to
19 use the reserved capacity, the right may be resold.

20 An open access design meets the transmission rate design objectives I
21 described above as follows:

- 22 • It prices transmission services at average costs, thus ensuring the full
23 collection of the TRR.
- 24 • Its simple postage stamp rates are easy to implement, with well-
25 understood terms and conditions that follow FERC's *pro forma* tariff.
- 26 • Being the industry standard, it is easy to use by all eligible customers.

- 1 • By adhering to the terms and conditions contained in FERC's *pro forma*
2 tariff, it offers open and comparable access to all eligible users.
- 3 • It is equitable because it allocates fixed costs among all long term
4 transmission users (i.e, Native Load, Network, and PTP customers)
5 according to their estimated relative usage of the system.
- 6 • It promotes efficiency because the grid is primarily used by the integrated
7 utility, which can operate the grid efficiently and reliably under the
8 centralized decision-making allowed by the tariff code of conduct, with full
9 information on such key variables as plant availability, operating costs,
10 line loadings, and demand. Moreover, the *pro forma* tariff permits rate
11 discounting that can help reduce a temporary capacity surplus on a
12 particular transmission path. The discount policy can be effective if (a)
13 the demand for transmission service is price-sensitive, and (b) the rate
14 discount is not limited by the local regulatory framework. Finally, when
15 necessary, the open access tariff resolves capacity shortages by
16 curtailing services with the lowest priority first (notwithstanding that
17 curtailment is rare for HQT's generally uncongested system).
- 18 • It promotes energy trading by minimizing differences in tariff rules, access
19 terms and conditions, and scheduling systems between a local jurisdiction
20 and its neighbors.
- 21 • It is appropriate for a regulated market environment in which an
22 integrated utility, such as HQ, serves native loads, and trades with
23 neighboring jurisdictions.

24 The preceding analysis suggests that an open access design, like the one
25 adopted by the Régie for HQT's existing OATT, is appropriate for Québec. In
26 contrast, Section 6 below will show that, at this time, a pool design is
27 unsuitable for the province in the relevant time horizon of this proceeding.

1 **3. HQT'S EXISTING OATT**

2 **3.1. Overview**

3 Effective as of January 2001, HQT's existing OATT has an open access
4 design that follows FERC's *pro forma* tariff. As such, it meets the
5 transmission pricing objectives, as explained in Section 2.4 above.

6 HQT's existing OATT has several key components, including Network
7 Integration Transmission Service (NITS), Native Load Service (NLS), Long-
8 Term Point-to-Point (LT-PTP) Service, Short-Term Point-to-Point (ST-PTP)
9 Service, rate discount policy in connection to ST-PTP service, Ancillary
10 Services (AS), and the treatment of the costs of Inter-Connection and
11 Network Upgrade (ICNU). When appropriate and convenient, my testimony
12 will refer to NITS and NLS together as Network services. Each of these
13 components is detailed below.

14 **3.2. Revenue Allocation**

15 **3.2.1. *Between NITS/NLS and LT-PTP***

16 HQT uses a 7-step process to allocate its Transmission Revenue
17 Requirement (TRR) among its long term transmission services:

18 Step 1: Determine HQT's TRR for the appropriate forward test year
19 period, which is calendar year 2005 for this application. The
20 TRR was approved by the Régie in Phase 1 of the current
21 case.

22 Step 2: Estimate the revenues to be collected from ST-PTP sales over
23 the same test year period.

1 Step 3: Subtract the ST-PTP revenues from the TRR from Step 1 to
2 develop an estimate of the Net TRR to be collected from NITS,
3 NLS and LT-PTP customers.

4 Step 4: Estimate the transmission system's single coincident peak
5 (1-CP), the total transmission load at the time of the
6 transmission system's annual peak. This step entails
7 estimating the coincident peak loads of the LT-PTP, NITS and
8 NLS customer classes. The peak load estimates of NLS are
9 based on a normal weather forecast and include losses. The
10 LT-PTP forecast is based on reservations.

11 Step 5: Divide the Net TRR by the 1-CP load from Step 4 to develop
12 the annual LT-PTP rate.

13 Step 6: Estimate the LT-PTP revenues as the product of LT-PTP rate
14 times an annual forecast of LT-PTP reservations.

15 Step 7: Subtract the LT-PTP revenues from the Net TRR to develop an
16 estimate of the network revenues. Network revenues are then
17 allocated to each network customer, who may receive NITS or
18 NLS, based on the customer's load ratio share of HQT's 1-CP.

19 HQT proposes the continued use of 1-CP to determine a fair allocation of
20 costs between LT-PTP, Network, and Native Load Services. HQT's proposal
21 is based on its argument in the last OATT case before the Régie: the 1-CP
22 method was more appropriate than 12-CP because HQ's system planning
23 was based on the estimated annual peak load. HQT reaffirms the same
24 argument in this application because the annual peak continues to be the
25 main determinant of HQT's transmission costs.

1 **3.2.2. Federal Energy Regulatory Commission (FERC) tests**

2 To further gauge the reasonableness of HQT's proposed use of the 1-CP
3 method, I have performed four tests commonly used by FERC:

- 4 1. A comparison between (a) the average of system peaks (as a
5 percentage of annual peak) during the peak months, and (b) the
6 average of the system peaks (as a percentage of the annual peak)
7 during the remaining months. This comparison is calculated as the
8 difference between the average peak load during the peak months and
9 the average peak load during the off-peak months, divided by annual
10 maximum peak load. The highest-usage months for HQT are
11 December, January, February, and March.
- 12 2. Average of 12 monthly peaks as a percentage of the annual peak.
- 13 3. Lowest monthly peak as a percentage of the annual peak.
- 14 4. The likelihood that peak demands in non-peak months exceed the
15 peak demands in the peak months.

16 If the system demand is relatively flat over the 12 months, the FERC
17 precedent supports the use of the 12-CP method. If the utility experiences a
18 pronounced peak, during 1, 3 or 4 months, the FERC precedent supports the
19 use of another CP method.

20 When interpreting the results of the first three tests in Table 1 below, I
21 recognize that the published FERC decisions distinguish the 12-, 4- and 3-CP
22 systems from one another instead of the less commonly found 1-CP
23 systems.³ However, the tests are still useful to distinguish HQT's clearly

³ Michael E. Small, "A Guide to FERC Regulation and Ratemaking of Electric Utilities and other Power Suppliers," Edison Electric Institute, 1994.

1 defined peak load, which is consistent with a 1-CP allocation, from systems
 2 with flatter loads that are consistent with a 12-CP allocation.

3 The Test 1 result in Table 1 shows that HQT is not similar to utilities using a
 4 12-CP method. HQT is most similar to those using a 3- or 4-CP method. The
 5 Test 2 result also shows that HQT is most similar to utilities using the 3- or 4-
 6 CP method. The Test 3 result shows that HQT matches most closely with
 7 utilities using the 3-CP method.

8 **Table 1: Summary of FERC Test Results**

Test	Range of allocation test results referenced in text of "A Guide to FERC Electric Utility Ratemaking"	Results for HQT (based on forecasted 2005 data) ⁴
1. Difference between average of system peak during peak months, as a percentage of annual peak, and average of system peaks during other months, as a percentage of the annual peak.	12-CP: 18% - 19% 4-CP: 16.4-24.9%; 26%; 31 %; 3-CP: average of 22.9%, high of 28.3%	27%
2. Average of 12 monthly peaks as a percentage of annual peak	12-CP: 81% - 88% 4-CP: 79.4% - 81.2% 3-CP: 80.1%	77%
3. Lowest monthly peak as a percentage of the annual peak	12-CP: 66% - 79% 4-CP: 55.8% - 67.8% 3-CP: 58%	60%

9 Note: Test 4 results are not given in percent of annual system peak and
 10 therefore are discussed in the text immediately following this table.

11 The last test entails identifying the timing of HQT's system peak. The Test 4
 12 result indicates that among those utilities studied, HQT is most similar to

⁴ The most recent available actual HQT data is for 2004. Using this data produces essentially the same results as the planning data for 2005. The results for Test 1 (27%) and Test 3 (60%) are identical, while Test 2 yields a minimally different result (76% instead of 77%).

1 utilities using a 3-CP method. Importantly, the FERC cases involving Tests 1-
2 3 show that FERC has adopted a 3-CP method even in two cases in which
3 the annual peak occurred outside the peak months once in a 4-year period.⁵
4 HQT's planning data shows that HQT's expected annual peak never occurs in
5 the off-peak months of April through November during the 7-year period of
6 1999-2005.

7 In summary, results from Standard Tests developed by the FERC are useful
8 for clearly rejecting the 12-CP method but less so for distinguishing the 1-, 3-
9 and 4-CP methods.

10 **3.2.3. Supplemental analysis**

11 To help distinguish between the appropriateness of using 1-, 3- and 4-CP
12 methods, I completed a supplemental analysis entailing three additional tests.
13 Two of these supplemental tests rely on HQT's planning data. According to
14 HQT-3, Document 1, HQT continues to plan its system to provide adequate
15 transmission capacity to meet its system peak load. In HQT's planning
16 process, system peak load is derived from the sum of the coincident peak
17 demands of NLS, NITS and LT-PTP customers. The NLS Forecast is
18 weather normalized and given to HQT by HQ Distribution each year.
19 Currently, there are no NITS customers. LT-PTP reservations are developed
20 from the actual reservations over the previous 12 months. Table 2 below
21 shows HQT's forecast of its planned monthly peak loads for 2005, the sum of
22 monthly NLS forecasts and LT-PTP reservations. The weather-normalized
23 expected demand from NLS customers will peak in January at 34,060 MW.
24 The expected LT-PTP reservations in 2005 are 405 MW. Hence, HQT must
25 plan to serve 34,465 MW of peak demand in January of 2005.

⁵ Small, "A Guide to FERC Regulation and Ratemaking."

1 **Table 2: HQT's 2005 Forecast Monthly Transmission System Peak Loads (MW)**

Month	2005	2005	2005
	Native Load	Point to Point	Monthly System Peak
Jan	34,060	405	34,465
Feb	32,331	405	32,736
Mar	29,913	405	30,318
Apr	25,589	405	25,994
May	22,053	405	22,458
Jun	20,359	405	20,764
Jul	20,768	405	21,173
Aug	20,822	405	21,227
Sep	21,049	405	21,454
Oct	24,237	405	24,642
Nov	28,271	405	28,676
Dec	33,112	405	33,517

2 Table 3 below shows HQT's total monthly system peak demands for each
 3 year from 1999 through 2005. These monthly peak demands were estimated
 4 in the same way as the 2005 estimates in Table 2, with the exception that the
 5 data are based on actual point-to-point and weather normalized Native Load
 6 Service rather than forecasted data.

7 **Table 3: HQT's Monthly System Peak Loads for 1999 through 2005 (MW)**

Month	1999	2000	2001	2002	2003	2004	2005
	Monthly System Peak	Monthly System Peak	Monthly System Peak	Monthly System Peak	Monthly System Peak	Monthly System Peak	Monthly System Peak
Jan	34,087	35,330	36,193	35,279	36,191	34,700	34,465
Feb	32,484	34,112	34,132	33,892	34,530	32,811	32,736
Mar	29,961	30,872	31,763	31,365	31,791	30,286	30,318
Apr	26,115	26,669	27,337	27,262	27,950	25,356	25,994
May	22,702	23,454	23,996	24,020	23,496	21,604	22,458
Jun	20,720	22,166	22,170	22,405	21,121	20,109	20,764
Jul	20,841	22,095	22,600	22,637	21,349	19,958	21,173
Aug	20,854	22,368	22,407	22,650	21,466	20,228	21,227
Sep	21,497	23,075	22,929	23,102	21,816	20,386	21,454
Oct	23,976	25,945	26,334	26,199	25,027	23,072	24,642
Nov	27,881	30,052	30,207	30,267	28,960	27,970	28,676
Dec	32,266	34,470	34,062	34,728	33,902	32,671	33,517

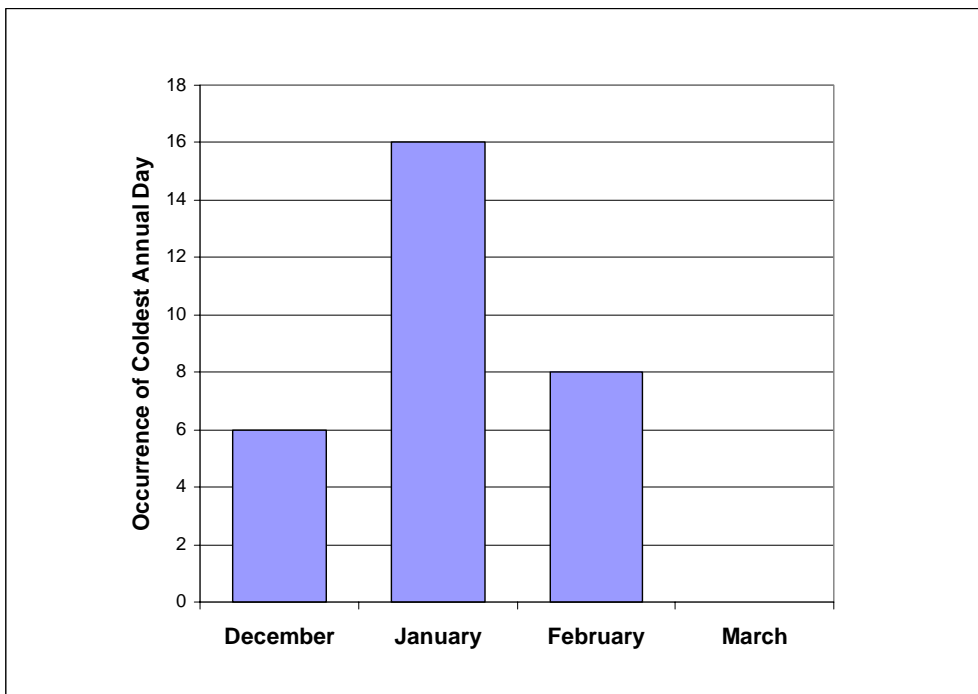
1 The first test examines the consistency of the planning assumption that the
2 transmission system peak load occurs in January. Table 3 above shows that
3 over the seven year period of 1999-2005, HQT's annual system peak was
4 expected to occur in January of each year.

5 The second test examines the size of the difference between the expected
6 peak load in January and the next highest expected monthly peak load over
7 the same 7 year period. The expected average peak load in January over the
8 7 year period was 35,178 MW. The expected average peak load in the next
9 highest month was 33,810 MW, 1,368 MW lower (4%) than the expected
10 peak in January.

11 Finally, I examined 30 years of temperature data to determine the frequency
12 with which the coldest day of each year falls into each of the four winter
13 months of December through March. Figure 1 below shows that over the
14 30-year period of 1971-2000, the coldest day in Montreal occurred 16 times
15 (53% of 30 years) in January, 8 times (27% of 30 years) in February, and 6
16 times (20% of 30 years) in December. Finally, as the coldest days in
17 February occurred in the first half of the month, 72 percent of the coldest days
18 in a given year occurred in the 44-day window of December 31-February 12.

1
2

Figure 1: Occurrence of Coldest Annual Day in Montreal over the 30 year period between 1971 and 2000



3

4 The results of these supplemental tests lead me to conclude: (a) the single
5 peak load is consistently predicted to occur in January; (b) the large
6 difference between the January peak and the peak in the next highest month
7 eliminates the peak loads in other months as a driver of HQT's investment in
8 transmission capacity; (c) the coldest day most frequently occurs in January,
9 and (d) 72% of all coldest days occur within a 44-day window between
10 January and early February.

11 These supplemental tests clearly indicate that it is reasonable to allocate
12 HQT's transmission revenue requirement according to each transmission
13 service class' contribution to the single system coincident peak load in
14 January. Although the 12-CP cost allocation method is certainly more
15 commonly used than the 1-CP method, FERC has approved the use of a
16 1-CP method for jurisdictions that have peak loads that are highly
17 concentrated in a single month. For example, PJM bills their network

1 customers based on the customer's load coincident with the annual peak of
2 different zones.

3 **3.3. Point-to-Point (PTP) Service**

4 PTP service aims to provide the service necessary for transmitting electricity
5 from a specific POR to a specific POD. It is intended for electricity export out
6 of Québec, and wheeling through Québec. An open access design offers a
7 variety of PTP services, as explained below.

8 **3.3.1. Long-term point-to-point service (LT-PTP)**

9 Offered under Schedule 7 of HQT's existing OATT and Schedule 9 of the
10 proposed OATT, this service is designed to help a seller to fulfill its delivery
11 obligation and a buyer to fulfill its withdrawal obligation under a long-term
12 contract that lasts more than a year. It allows a transmission user to reserve
13 firm capacity, for a period of not less than one year, to transmit electricity from
14 a specific POR to a specific POD. The \$/kW-year rate is based on the 1-CP
15 method, as explained in Section 3.2 above.

16 HQT should not change the LT-PTP rate design. HQT proposes to continue
17 to use a standard long term design that fairly allocates fixed costs between
18 LT-PTP, Network, and Native Load Service customers. While there has been
19 some displacement of LT-PTP reservations with shorter term point-to-point
20 service, HQT maintains that this has been mainly caused by the evolution of
21 day-ahead and hourly markets in neighboring jurisdictions. In this regard, I
22 agree with HQT's point of view. Therefore, lowering the LT-PTP rates is
23 unlikely to increase LT-PTP revenues. Conversely, increasing the LT-PTP
24 rates is not supported by reasonable cost allocation methods.

1 **3.4. Short-term point-to-point service (ST-PTP)**

2 **3.4.1. Firm vs. non-firm service**

3 ST-PTP service under the open access design has two reliability levels: firm
4 and non-firm. If curtailment is necessary, non-firm service will be cut before
5 firm service. If curtailment of firm service on a particular transmission path
6 becomes necessary, it is done in proportion to each user's total firm service
7 reservation, which may consist of both LT-PTP and ST-PTP.

8 Reliability differentiation of transmission service is important and useful for
9 two reasons. First, when an unexpected shortage occurs, a transmission
10 provider's ability to curtail is critical for maintaining reliable grid operation.
11 Second, non-firm service allows a transmission provider to sell transmission
12 capacity on an as-available basis. Because surplus capacity is at times
13 available under non-stress conditions, the sale of non-firm service may
14 improve capacity utilization. However, if selling non-firm service at lower
15 rates leads to a transmission user's substituting non-firm for firm service, it
16 only causes revenue loss to the transmission provider, without improving
17 capacity utilization.

18 **3.4.2. Firm service**

19 Offered under Schedule 7 of HQT's existing OATT and Schedule 9 of the
20 proposed OATT, this service aims to help a seller to meet its delivery
21 obligation and a buyer to meet its withdrawal obligation under a short-term
22 contract that lasts less than a year. It allows a transmission user to reserve
23 firm capacity, for a period of less than one year, to transmit electricity from a
24 specific POR to a specific POD.

25 The monthly rate (\$/kW-month) is 1/12 of the annual \$/kW-year rate for the
26 LT-PTP service. The weekly rate is 1/52 of the annual kW-year rate. The
27 daily rate is 1/5 of the weekly rate, following the "American Electric Power

1 (AEP)” or Appalachian method for developing a peak period rate described in
2 FERC’s Opinion No. 440 (p.26).

3 As indicated in HQT’s existing OATT, there was a 25% discount for the period
4 of May 15, 2002 through January 14, 2003 due to the Régie’s decision (D-
5 2002-95, p. 280) to use discounting, in an effort to improve capacity
6 utilization. The Régie has not continued its mandatory discount policy.

7 HQT should not change the existing ST-PTP firm rate design which currently
8 does not have a mandatory discount. As I will discuss further in Section 4,
9 HQT’s existing and proposed rate for hourly non-firm service carefully
10 balances the competing goals of making sure that the rate is sufficiently high
11 to assure that each customer makes a positive contribution to fixed costs, and
12 sufficiently low to encourage efficient transmission use.

13 **3.4.3. Non-firm service**

14 Offered under Schedule 8 of HQT’s existing OATT and Schedule 10 of the
15 proposed OATT, this service allows a transmission provider to sell, and a user
16 to buy, non-firm transmission capacity on an as-available basis, for a period
17 of less than one year, to transmit electricity from a specific POR to a specific
18 POD. The monthly \$/kW-month rate is 1/12 of the annual \$/kW-year rate for
19 the LT-PTP service. The weekly rate is 1/52 of the annual kW-year rate. The
20 daily rate is 1/7 of the weekly rate. The hourly rate is 1/24 of the daily rate.

21 HQT’s hourly rate is non-firm and follows the off-peak pricing formula in
22 FERC’s Opinion No.440 (p.26) which establishes an hourly rate formula
23 based on time of use pricing. The peak transmission rate, based on the AEP
24 method, is equal to the annual rate (\$/kW-year) divided by 4160 hours (16
25 hours x 5 days x 52 weeks); and the off-peak rate is equal to the annual rate
26 (\$/kW-year) divided by 8760 hours (24 hours x 7 days x 52 weeks).

1 Although discounting applicable to all short term services was discontinued on
2 January 14, 2003, the 25 percent discount was extended by the Régie's
3 decision (D-2003-02) for hourly non-firm service until January 14th 2004.

4 I maintain that the Régie should discontinue its mandatory discount policy
5 because a non-discretionary non-firm rate discount only leads to service
6 substitution and revenue loss, without improving HQT's capacity utilization.
7 Section 4 below will provide further reasons for my opinion here.

8 **3.5. Ancillary services (AS)**

9 Ancillary services are necessary for maintaining reliable grid operation by
10 HQT. HQT has an obligation to provide AS as the supplier of last resort, but
11 only passes through the prices provided by the AS supplier. The AS prices, in
12 HQT's case are based on the opportunity costs to provide them. The AS in
13 HQT's OATT are:

- 14 • Voltage control service (Schedule 2 in both existing and proposed OATT)
15 to maintain acceptable voltage limits on HQT's transmission facilities;
- 16 • Frequency control service (Schedule 3 in both existing and proposed
17 OATT) to continuously balance generation resources and loads at 60 Hz
18 per second;
- 19 • Energy imbalance service of two kinds: (1) to remedy the difference
20 between a transmission user's scheduled and actual *delivery* of energy
21 (Schedule 4 in existing OATT and Schedule 5 in proposed OATT), and
22 (2) to remedy the difference between a transmission user's scheduled
23 and actual *receipt* of energy (currently not offered in existing OATT and
24 proposed to be offered in Schedule 4 of proposed OATT).

- 1 • Spinning reserve service (Schedule 5 in existing OATT or Schedule 6 in
2 proposed OATT) to ensure continuity of service under first-contingency
3 conditions on the system;
- 4 • Non-Spinning reserve service (Schedule 6 in existing OATT or Schedule
5 7 in proposed OATT) to serve load in the event of a system contingency.

6 HQT's proposed AS designs continue to be very similar to those offered in
7 many other open access jurisdictions, and fulfill HQT's requirement to be the
8 supplier of last resort of these services.

9 **3.6. Inter-connection and network upgrade (ICNU)**

10 HQT's existing OATT uses a rolled-in treatment of a portion of ICNU costs.
11 ICNU cost is triggered by a firm service request and is included in HQT's rate
12 base. The ICNU cost is subject to a cap of \$522/kW in the current OATT.
13 The cap is based on the 20-year present value of the firm service request's
14 margin, estimated using the annual rate, less operation and maintenance
15 costs. HQT proposes to update the cap based on more recent parameters
16 from Phase 1 of this case.

17 The British Columbia Transmission Corporation (BCTC) has recently
18 proposed a method where customers would over time receive a full refund of
19 their interconnection and network upgrade costs as a credit to their service
20 bill. Also, FERC continues to advocate full rolled-in treatment of network
21 interconnection costs over a 5 year period. HQT's partial rolled-in treatment
22 strikes a balance between protecting existing transmission customers from
23 stranded costs, and mitigating what can be prohibitive new interconnection
24 and upgrade costs. Again, I see no reason why HQT should alter its ICNU
25 cost treatment method because there are no material changes in Québec's
26 electricity market environment or HQT's system conditions that justify altering
27 the partial rolled-in treatment of ICNU cost.

1 **4. DISCOUNT POLICY**

2 **4.1. Overview**

3 In the Discounting Final Report filed in this application, HQT recommends that
4 its proposed short term rates should not be discounted. HQT argues that the
5 25 percent discounts served mainly to reduce short-term revenues, without
6 achieving the intended goal of increasing system utilization.

7 I agree with HQT's conclusion that the mandatory 25 percent discount applied
8 to existing rates for off-peak short-term usage was not effective in increasing
9 off-peak usage.⁶ HQT's full non-discounted short-term point-to-point rates
10 were reasonably low already and were not inhibiting substantial levels of
11 trading and transmission use during the majority of the hours during the year.⁷
12 HQT's existing and proposed short-term rates are the result of (a) the use of a
13 1-CP allocation to set the long-term point to point rate; and (b) the use of
14 8,760 hours as the divisor to derive the hourly non-firm rate. The 1-CP
15 allocation is supported by my own analysis. The rate calculation for non-firm
16 service is consistent with rate calculations used by other utilities for mainly off-
17 peak service.

18 **4.2. Regulatory views on transmission rate discount**

19 In recommending discontinuance of the mandatory 25 percent discount, I am
20 cognizant of the discount policy in FERC's Order 888. That policy aims to

⁶ HQT's Final Discount Report : HQT-2, Document 3, Bilan de la politique transitoire de rabais.

⁷ HQT's analysis shows that the price discount did not increase transmission usage during off-peak hours. The analysis is based on the fact that the spread in market prices - an estimate of the market value of transmission - was in most hours already higher than the undiscounted full price of short term hourly non-firm transmission service.

1 promote utilization of transmission capacity that may lie idle in the absence of
2 a discount, thus improving fixed cost recovery and reducing rates for all grid
3 users. To ensure equal access, however, if a discount is given to one
4 transmission customer that uses a specific POD, the same discount must be
5 given to all reservations that have the same POD.

6 The Régie's objectives for discounting were similar to FERC's. They
7 supported the economic objective of using the discount to improve capacity
8 utilization and cost recovery from short-term service users, thus lowering the
9 costs paid by the native load.⁸

10 **4.3. Evaluation of the short-term rate discounting policy**

11 My evaluation is based on HQT's finding in connection to the Régie's decision
12 of a mandatory 25% discount for hourly off-peak service⁹ applicable from
13 January 15, 2003 through January 14, 2004. HQT finds that while HQT's
14 Transitional Discount Policy complied with all of the parameters set by the
15 Régie, it did not achieve the Régie's primary objective of increasing the off-
16 peak use of the system's available transmission capability. Moreover, the
17 analysis shows that the discounting actually reduced the contribution to fixed
18 costs made by short-term transmission users.

19 For the 1-year period in which the transitional discount was in effect, HQT's
20 analysis shows that third-party customers did not increase their off-peak
21 transmission use. Transactions by third-party customers would likely have
22 occurred in the absence of the discount because the value of transmission of
23 C\$15/MW-h was in most cases larger than HQT's undiscounted hourly
24 transmission rate. Furthermore, the analysis indicates that even if the value of

⁸ Decision D-2002-95, p. 280.

⁹ HQT-2, Document 3, *Bilan de la politique transitoire de rabais*.

1 transmission over the test period had been lower, off-peak discounting is
2 unlikely to have a material impact on HQT's sales.

3 The finding of no material impact is due to the following facts:

- 4 • Hydro-Québec Production (HQP) continues to be the largest user of
5 short-term point-to-point service, accounting for about 80 percent of the
6 test period's total short term transmission use.
- 7 • Over 70 percent of HQP's transmission use occurs during on-peak hours.
- 8 • Since the price discount was only offered during off-peak hours, off-peak
9 discounting, even when the market value of transmission is lower than the
10 transmission price, is unlikely to have a substantial impact on total short
11 term sales.

12 I have completed an independent analysis of the market value of transmission
13 to validate HQT's findings. My analysis uses a different measure of
14 transmission value than the one in HQT's Final Discounting Report.¹⁰ Based
15 on 2004 market price data, my measure of transmission value is the
16 maximum energy price spread between the on- and off-peak hours in HQ's
17 three neighboring energy markets: Ontario, New York (NY), and New England
18 (NE). My analysis assumes a transmission customer (who is engaged in day-
19 trading) would place a maximum value for HQT's short-term point-to-point
20 service equal to the difference between the lowest off-peak price in any of the
21 three markets and highest on-peak price in the same markets. My
22 transmission value computation is illustrated by the following example:

23 Example. Suppose the off-peak prices in Ontario, NY and NE were
24 \$30, \$35 and \$40 per MWh, implying that the lowest off-peak price

¹⁰ HQT used 2003 market price data to value transmission as the difference between the price of energy purchased in Ontario and delivered in either New York (NY) or New England (NE), assuming that the transaction passed through HQT's transmission system.

1 would be \$30 per MWh. If the on-peak prices in the same day were
2 \$60, \$70 and \$80 per MWh, the highest on-peak price would be \$80
3 per MWh. In this case the maximum daily value of transmission was
4 \$50 per MWh, the difference between the \$30/MWh minimum off-peak
5 price and the \$80/MWh maximum on-peak price.

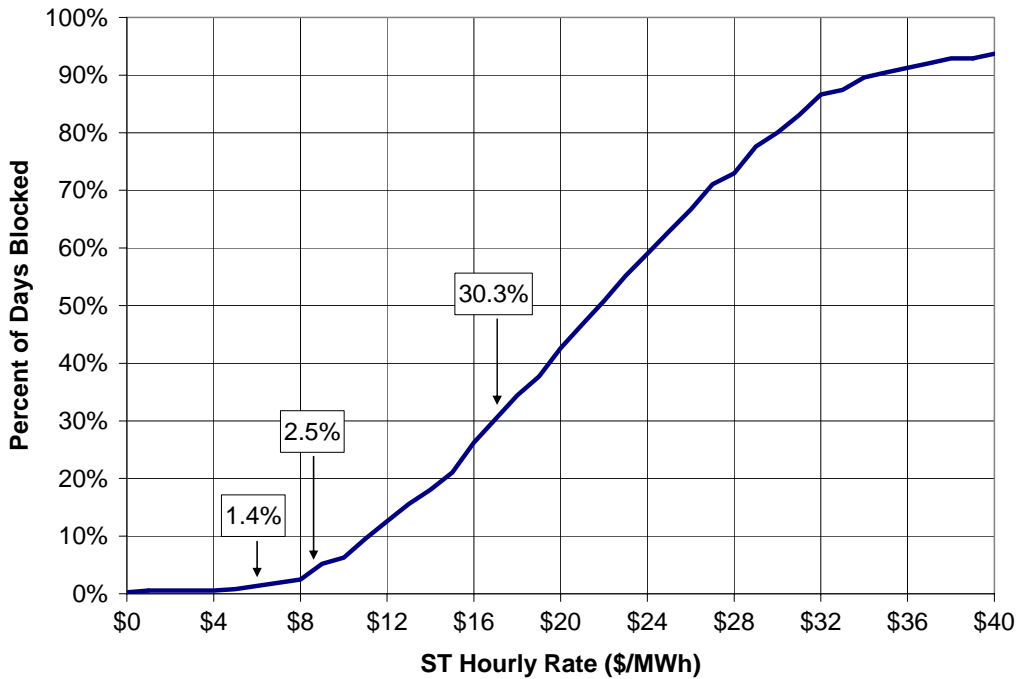
6 I then netted out the costs of ancillary services, losses, and other
7 transmission costs from the estimated maximum transmission values.

8 Results of the analysis are shown in Figure 2 below. This figure's horizontal
9 axis measures the \$/MW-h transmission rate. Its vertical axis is the
10 cumulative percent of days with a value below the transmission rate. This
11 figure indicates:

- 12 • HQT's existing rate of \$8.33/MW-h is sufficiently low and would only
13 block trade in 2.5% of the days in 2004. Reducing the \$8.33/MW-h rate
14 by 25% to \$6.25/MW-h would only reduce the percent of days blocked
15 to 1.4%.
- 16 • Adopting the AEP on-peak pricing formula would raise the \$8.33/MW-h
17 rate to a \$17.5/MW-h rate, which would block trade during 30.3% of
18 the days in 2004.

19 Hence, maintaining hourly transmission service prices in the \$8/MW-h range
20 balances the goals of fixed cost recovery and efficient capacity utilization. It
21 also promotes the goal of having stable long-term transmission rates.

1 **Figure 2: Percent of days in which trading is fully blocked by the short term**
 2 **hourly transmission service rates.**



3 My analysis also supports the broader HQT proposal that the Régie should
 4 not mandate an arbitrary discount on HQT’s ST-PTP transmission service.
 5 HQT’s proposed OATT already incorporates an appropriate level of
 6 discounting into its ST-PTP rates because HQT advocates, with reason, (a)
 7 the use of a 1-CP, instead of a 12-CP, allocation to set the LT-PTP rate; (b)
 8 the continued use of firm and non-firm short term pricing distinctions for
 9 service with reservation durations beyond 1 hour; and (c) the use of 8760
 10 hours (equivalent to a 100% load factor) as the divisor to derive the short-
 11 term non-firm rate. Hence, the resulting short-term rates should not be an
 12 obstacle to the economic use of transmission during most hours of the year.

1 **5. INCENTIVE REGULATION AND OATT**

2 At times used to regulate transmission companies,¹¹ incentive or
3 performance-based regulation (PBR) aims to offer incentives to induce the
4 transmission owner to meet a set of desirable goals and criteria (e.g., cost
5 cutting and reliability improvement). It is commonly implemented via a price
6 cap formula (CPI - X) so that the annual cap adjustment follows the CPI-
7 based inflation, net of a preset productivity target X. By breaking the tight
8 relationship between the utility's costs and rates, PBR via price capping is
9 seen as a remedy for the perceived deficiency of cost of service regulation
10 that it may lack strong incentives for the regulated utility to operate efficiently
11 or invest wisely beyond the incentives associated with a prudence review.

12 If PBR were to be implemented in Québec, a PBR price cap would mainly
13 affect HQT's TRR, not the structure of its OATT design. Hence, the Régie's
14 decision to adopt HQT's proposed OATT design should be independent of
15 any later determination regarding PBR.

16 **6. POOL DESIGN FOR QUÉBEC**

17 **6.1. Overview**

18 This section determines if, at this time, a pool design is suitable for Québec.
19 In doing so, it first describes a "pool design" of a transmission tariff associated
20 with an ISO or RTO operating the grid in an energy pool. It then evaluates
21 whether a pool design is appropriate for Québec.

22 The section's main conclusion is that, albeit its growing popularity, a pool
23 design is only used by ISOs and RTO's in Alberta, Ontario, New York, New
24 England, PJM, Midwest, Texas, and California. Thus, the open access

¹¹ Al-Sunaidy, A. and R. Green. 2005. "Electricity deregulation in OECD countries." *Energy- The International Journal*, forthcoming.

1 design per FERC's *pro forma* tariff remains the most popular design used in
2 North America. Since Québec does not have an ISO or a power pool with a
3 competitive generation market, a pool design is not appropriate for the
4 province.

5 **6.2. Description**

6 Pool designs have been implemented when two or more utilities have
7 combined operation of their transmission systems under an Independent
8 System Operator (ISO) or regional transmission organization (RTO). They
9 are typically instituted as part of electricity market restructuring that
10 encourages the development of competitive generation and retail markets, as
11 was done in Alberta, Ontario, New York, New England, PJM, Midwest, Texas,
12 and California. Instead of volumetric reservation charges, pool designs use
13 “access fees” typically assessed to loads or load-serving entities, to collect
14 the participating transmission owners’ TRR. Payment of an access fee
15 entitles the paying customer to inject and withdraw energy anywhere on the
16 grid.

17 In addition to access fees, grid users may also be required to pay a usage
18 charge to reflect the cost of managing transmission congestion. These
19 “congestion charges” can be positive or negative, depending on whether the
20 transmission usage contributes to or alleviates transmission congestion.

21 Congestion management systems ration transmission capacity by changing
22 the pattern of resource operations across the grid. For example, a generator
23 downstream of a constraint might submit an “inc” (incremental) bid to increase
24 its generation output, while a generator upstream might submit a “dec”
25 (decremental) bid to decrease its generation output. By accepting both bids,
26 the transmission provider changes the generation pattern to resolve
27 congestion. The congestion charge is based on the difference between the
28 inc and dec bids.

1 The most advanced pool designs integrate day-ahead and hour-ahead
2 energy, transmission, and ancillary services markets. Market participants bid
3 to buy and sell energy and ancillary services at various locations on the grid,
4 and the transmission provider selects the optimal resource patterns given the
5 bids. The dispatch is efficient if the bids are made by competitive buyers and
6 sellers and accurately inform the transmission provider of the short-run
7 marginal benefits and costs of various services.

8 The interaction of all bids through this process results in market-clearing
9 energy prices at each location on the grid. The difference between two
10 locational energy prices defines the value of transmission capacity between
11 the two locations and is the congestion charge to users that inject and
12 withdraw power in these locations. Because such charges can be volatile, a
13 user may hedge against congestion cost volatility with firm (or financial)
14 transmission rights (FTRs). All customers can purchase FTRs in annual,
15 seasonal or monthly auctions held by the transmission provider in advance of
16 the actual use of transmission service. Customers paying access fees
17 typically receive an allocation of FTRs, reducing or eliminating their need to
18 purchase additional rights.

19 Users of short-term service under pool designs do not pay fixed charges
20 because the TRR is collected from loads through access fees. However,
21 users of “export and through” service typically pay a separate reservation
22 charge to ensure that loads in neighboring regions that benefit from using the
23 transmission system also contribute to cost recovery.

24 New long-term service requests in jurisdictions with pool designs fall into two
25 categories: requests for interconnection, and purchase of FTRs. Because
26 congestion is managed through generation re-dispatch, new interconnections
27 do not necessarily require network upgrades, especially when the resulting
28 congestion cost is small relative to the cost of capacity expansion.

1 Interconnection grants a generator the right to inject power and make supply
2 bids into the pool. The generator can decide separately whether to pay
3 congestion charges in order to sell to a buyer in a different location, and
4 whether or not to acquire FTRs to help manage congestion cost volatility.
5 FTRs can be obtained by participating in auctions, buying from an existing
6 holder, or funding a transmission upgrade.

7 There are the two common forms of pool design:

- 8 • Locational marginal pricing (LMP) under which the transmission usage
9 charge is the locational price difference between the POD and POR that
10 are electric nodes in the grid. Jurisdictions using LMP include New
11 England, New York, PJM, MISO, and Texas.
- 12 • Zonal pricing used by California and Ontario. The transmission usage
13 charge is the price difference between the zones of receipt and delivery,
14 with each zone containing a collection of electric nodes. Hence, LMP has
15 finer delineation of transmission paths and charges than zonal pricing,
16 thus avoiding mispricing of transmission congestion that may occur within
17 a zone.

18 **6.3. Evaluation**

19 Here I determine if LMP meets some of the objectives of transmission pricing.
20 I find that LMP meets the following objectives:

- 21 • It imposes access charges on loads, thus ensuring the full collection of
22 the TRR.
- 23 • The terms or conditions are standardized for all users without regard to
24 affiliation, which promotes open and comparable access to all eligible
25 users.

- 1 • It promotes efficiency by equating the marginal benefit and cost of various
2 services.
- 3 • It facilitates trading, especially for an uncongested system whereby
4 traders pay practically zero congestion charges.
- 5 • It is appropriate for a restructured market environment in which
6 competitive sellers and buyers make transaction decisions based on
7 market prices.

8 However, LMP may not meet some of the transmission pricing objectives:

- 9 • It is not easy to implement because it requires sophisticated algorithms
10 and hardware to compute locational prices on a daily or even hourly
11 basis.
- 12 • While it is the industry standard for jurisdictions with a restructured
13 market, it is not easy to use when compared to an open access design.
- 14 • It will produce an inequitable distribution of fixed costs between different
15 classes of service because in an uncongested system, traders pay
16 practically zero charges and native load customers pay for the entire TRR
17 via access fees.

18 Besides its failure to meet some of the transmission pricing objectives, LMP is
19 not applicable to Québec's electricity market environment for the following
20 reasons:

- 21 • Québec's regulated market does not have retail access. A single
22 integrated utility, HQ, serves nearly all of the loads in Québec by
23 efficiently and reliably operating its generation resources in a grid that is
24 rarely capacity-constrained.

- 1 • LMP may be inconsistent with Québec’s regulatory constraints of (a)
2 uniform rates throughout the region served by HQT’s transmission
3 system, and (b) the Régie not granting discretionary pricing authority to
4 HQT.

5 **7. COMPARISON: HQT’S PROPOSED OATT VS. INDUSTRY STANDARD** 6 **DESIGNS**

7 **7.1. Overview**

8 The objective of this section is to compare HQT’s proposed OATT with
9 industry standard designs to determine if HQT’s proposal is consistent with
10 those designs. The comparison is based on my general knowledge of the
11 industry, plus a survey of transmission tariffs that I coauthored.¹² My paper
12 included transmission providers in the Canadian jurisdictions of British
13 Columbia, Alberta, Ontario, and Quebec, and in the U.S. jurisdictions of the
14 Bonneville Power Administration (BPA), Puget Sound Energy, Portland
15 General Electric, California ISO, Pennsylvania-New Jersey-Maryland (PJM),
16 ISO-New England, New York ISO, and Texas (ERCOT). In addition, for the
17 purposes of this review I have also reviewed transmission tariffs in the
18 Canadian jurisdictions of Manitoba, Saskatchewan, and New Brunswick, and
19 in the U.S. jurisdictions of the Southern Company, Entergy, and Midwest ISO.
20 The comparison includes jurisdictions with different types of generation mix
21 (e.g., predominantly thermal vs. mainly hydro), as well as different regions of
22 North America (e.g., Pacific Northwest vs. Atlantic Eastern Seaboard).

23 This comparison focuses in turn on (1) Long Term Service Rate Design; (2)
24 Short-Term Service Rate Design; (3) Export Fees; (4) Billing Determinants;
25 and (5) Ancillary Services. My main conclusion from the tariff comparison is

¹² Lusztig, C., P. Feldberg, R. Orans and A. Olson (2005) “A survey of transmission tariffs in North America,” *Energy-The International Journal*, forthcoming.

1 that HQT's proposed tariff is consistent with the OATTs of open access
2 jurisdictions without an ISO and a power pool.

3 **7.2. Comparison**

4 **7.2.1. Long-Term Service Rate Design**

5 HQT's long-term service rate design is very similar to those of the open
6 access jurisdictions in North America without an ISO and a power pool:

- 7 • Canadian open access jurisdictions: Saskatchewan, Manitoba, New
8 Brunswick and British Columbia. Except for BC Hydro's OATT, which
9 incorporates path-specific incremental costs, all of them have
10 implemented a FERC *pro forma* tariff design.
- 11 • U.S. open access jurisdictions: Puget Sound, Portland, Southern,
12 Entergy, Bonneville Power Administration (BPA). All of them offer LT-
13 PTP services per FERC's *pro forma* tariff. This is notwithstanding that
14 BPA has separate "pancaked" rates for its Southern Intertie and for
15 Montana.

16 **7.2.2. Short-Term Service Rate Design**

17 HQT's proposed design of its short-term PTP (ST PTP) rates is consistent
18 with the designs offered in the following Canadian open access jurisdictions:

- 19 • HQT's proposed monthly rate is 1/12 of its annual rate, the same as
20 SASKPOWER, Manitoba Hydro and New Brunswick Power.
- 21 • HQT's proposed weekly rate is 1/52 of its annual rate, the same as
22 SASKPOWER, Manitoba Hydro and New Brunswick Power.
- 23 • HQT's proposed daily firm service rate is 1/5 of its weekly rate, the same
24 as SASKPOWER, Manitoba Hydro and New Brunswick Power for their
25 peak daily rates.

- 1 • HQT's proposed daily non-firm service rate is 1/7 of its weekly rate, the
2 same as Manitoba Hydro and New Brunswick Power for their off-peak
3 daily rates.
- 4 • HQT's proposed hourly non-firm rate at 1/24 of its non-firm daily rate, the
5 same as Manitoba Hydro and New Brunswick Power for their hourly off-
6 peak rates.
- 7 HQT's proposed ST-PTP rate design is also consistent with the designs
8 offered in U.S. open access jurisdictions.
- 9 • Monthly and weekly rates : Puget, Portland, Southern and Entergy have
10 maximum monthly and weekly rates equal 1/12 and 1/52 of their annual
11 rates.
- 12 • Daily rates : Puget and Portland have daily peak and off-peak rates at 1/6
13 and 1/7 of their weekly rates. Southern and Entergy have daily peak and
14 off-peak rates at 1/5 and 1/7 of their weekly rates.
- 15 • Hourly rates : Puget, Portland, Southern and Entergy have peak and off-
16 peak hourly rates at 1/16 and 1/24 of their daily rates.

17 **7.2.3. BC Hydro Short-Term Rate Design**

18 British Columbia Transmission Company (BCTC) is the transmission provider
19 most comparable to HQT. BC Hydro makes use of a FERC *pro forma* tariff
20 design to actively participate in markets in the Western U.S. and Alberta.
21 BCTC's largest customer is BC Hydro. To effectively promote utilization of its
22 transmission assets and efficient levels of trade, BCTC's short-term PTP
23 service is priced based an estimate of transmission market value. BCTC has
24 also recently experienced substantial reductions in its PTP revenues, due
25 primarily to lower transmission use. In response to this decline, BCTC has
26 proposed, in its most recent Application before the BCUC (August 3, 2004), to

1 update its indexed pricing formula to more closely track transmission market
2 values. BCTC's proposal would reduce the average short term rate from
3 approximately \$4.26 per MW-h to \$3.05 per MW-h. BCTC estimated that this
4 reduction would substantially reduce the number of hours during which the
5 transmission tariff would block efficient use of transmission service, from
6 approximately 12.3 per cent to 6.9 per cent of the hours in the year.¹³

7 BCTC's proposed ST-PTP rate is set at the minimum of a) the full non-
8 discounted hourly rate; or, b) 1/4 of an estimated value of transmission
9 between Alberta and the California Oregon border (COB).¹⁴ The full non-
10 discounted rate for hourly service is set using FERC's AEP off-peak pricing
11 formula, which is equal to the annual rate of \$6.30 per MW-h (\$55.39 per kW-
12 year divided by 8760 hours). Since 1997 BC Hydro has used a variant of the
13 AEP pricing formula to set the maximum rate for its short term hourly service
14 that is identical to the design proposed by HQT. BCTC's most recent
15 application before the BCUC shows a continued support for this short-term
16 PTP design.

17 In light of BC Hydro's short-term design, one may be tempted to argue that
18 BC Hydro's indexed rate formula may be suitable for HQT. Neither the
19 transmission value computation I performed in Section 4 of this testimony, nor
20 HQT's own analysis described in its Final Discounting Report, supports this
21 line of reasoning. If applied in Québec, BC Hydro's short-term rate formula
22 would produce an average rate of approximately \$3.75/MW-h (= \$15/MW-h ÷
23 4), as HQT's Discounting Final Report indicates a \$15/MW-h transmission
24 value based on the average price difference between markets outside the

¹³ See Response to BCTC response to BCUC Information Request No. 1
27.1 Dated 23 August, 2004

¹⁴ The estimated transmission value is the difference between the price of
electricity in Alberta and the Mid-Columbia pricing point in the Pacific
Northwest. See BCTC Application for Open Access Tariff, December
9th, 2004 p.63.

1 province. The resulting decrease in the hourly rate to \$3.75/MW-h would
2 have two opposing revenue effects: (1) the decrease from \$8.33/MW-h to
3 \$3.75/MW-h would raise transmission reservations, yielding a revenue gain
4 from the increased transactions; but (2) the same rate decrease also causes
5 a revenue loss due to lower prices for existing reservations. Because of the
6 insensitivity of reservation levels to price documented by HQT, the net
7 revenue effect would be a loss in HQT's PTP revenue, which in turn would
8 increase the transmission rates for Quebec's native load consumers. I do not
9 believe this form of indexed pricing is appropriate for Quebec, given its high
10 cost of implementation and the resulting shift of fixed costs to native load
11 consumers.

12 My opinion here is consistent with my prior testimony before the BCUC in
13 connection to BCTC's 2004 OATT application, in which I advocated
14 discounting. In that case I estimated that the undiscounted transmission rate
15 in BC would block efficient use of the transmission system more than
16 12 percent of the time. This is because there are many hours in BC during
17 which the transmission value would not exceed the full average-cost based
18 rate. This is in sharp contrast to HQT's, and my own, analysis showing that
19 HQT's proposed ST-PTP rates for hourly non-firm service would not inhibit
20 substantial levels of trading.

21 **7.2.4. Export Fees**

22 Except for BPA, all open access designs collect their fixed costs primarily
23 through their long-term reservation charges. Hence, HQT's lack of wheeling
24 and export fee is not at odds with the open access designs used in open
25 access jurisdictions without an ISO and a power pool.

26 In contrast, power pools typically collect the majority of their fixed costs from
27 loads; and they sometimes require the use of a wheeling or an export fee to
28 ensure a fair contribution to fixed costs by marketers and generators.

1 **7.2.5. Billing Determinants**

2 HQT's existing and proposed billing determinants continue to be consistent
3 with those used in most open access jurisdictions.

4 **7.2.6. Ancillary Services**

5 The ancillary services in HQT's proposed OATT are similar to those offered at
6 average costs by the open access jurisdictions. All of the open access
7 jurisdictions offer the required services of (1) Scheduling, System Control and
8 Dispatch and (2) Reactive Supply and Voltage Control. Other services
9 offered to load-serving customers within the control areas include:
10 (3) Regulation and Frequency Response; (4) Energy Imbalance;
11 (5) Operating Reserve – Spinning; and (6) Operating Reserve –
12 Supplemental.

13 **8. CONCLUSION**

14 The overall recommendation of my testimony is that HQT's proposed OATT
15 should be adopted in its entirety. This recommendation is driven by the
16 following compelling reasons:

- 17 • The proposed allocation of fixed transmission costs between long term
18 service classes is fair and justified by HQT's long term planning that aims
19 to meet the single CP, which almost always occurs in January each year.
- 20 • The combination of using a 1-CP allocation to determine the LT-PTP rate
21 and the continued use of non-firm rate computed at a 100% load factor
22 produces a simple and relatively low rate that obviates the need for a
23 complicated rate formula like BC Hydro's or a mandatory rate discount
24 that the Régie previously ordered.
- 25 • Comparison of HQT's proposed design to the industry standard designs
26 confirm that albeit the growing use of a pool design like LMP in

1 jurisdictions with an ISO and a power pool, the open access jurisdictions
2 continue to successfully use FERC's *pro forma* tariff to facilitate
3 wholesale energy trading and unbundled transmission pricing.

APPENDIX

CURRICULUM VITAE OF DR. REN ORANS

Curriculum Vitae of Dr. Ren Orans

Ren Orans

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Dr. Orans founded the consulting firm Energy and Environmental Economics (E3) in 1993. The firm has three main practice areas: Litigation Support, Utility Planning and Business Restructuring. The firm has nationally recognized experts in the fields of transmission and distribution planning, economic and regulatory theory and finance. Dr. Orans heads the Litigation Support and Utility Planning practices for E3.

ENERGY & ENVIRONMENTAL ECONOMICS, INC.
Managing Partner

San Francisco, CA
1993 – Present

Dr. Orans' work in utility planning is centered on the design and use of area- and time-specific costs for electric utilities. The first successful application was conducted for Pacific Gas and Electric Company in their 1993 General Rate Case. Using costs developed by Dr. Orans, PG&E became the first electric utility to use area and time specific costing in its ratemaking process. This seminal work led to detailed area costing applications in pricing, marketing and planning for Wisconsin Electric Company, Niagara Mohawk Power Company, Public Service of Indiana, Kansas City Power and Light, Central and Southwest Utilities, Philadelphia Electric Company, Tennessee Valley Authority and Ontario Hydro. This work has been formalized in Dr. Orans' Dissertation, Area-Specific Costing for Electric Utilities, A Case Study of Transmission and Distribution Costs (1989) and a more recent NARUC report revising the California Standard Practice Guidelines for Evaluating DSM programs (2000).

Dr. Orans expertise in utility planning is complemented by his practical working experience at Pacific Gas and Electric Company (PG&E), where he was responsible for designing their electric utility rates between 1981 to 1985. He has relied on this background along with his published papers to provide expert testimony on transmission pricing on behalf of BC Hydro (1996 and 1997), Ontario Power Generation (2000) and Hydro Quebec (2001). Dr. Orans has also testified in stranded asset cases before the British Columbia Utilities Commission and the Texas PUC on behalf of BC Hydro and Central Power and Light, respectively. Dr. Orans was most recently PG&E's expert witness of avoided generation costs in their 2005 rate case. Earlier this year, Dr. Orans testified before the BCUC on behalf of the newly formed British Columbia Transmission Corporation (BCTC), where he described a number of proposed revisions to their electric transmission tariff. He is currently representing British Columbia in their negotiations with other members of Grid West to form an RTO.

DEPARTMENT OF ENERGY
NATIONAL RENEWABLE ENERGY LABORATORY
ELECTRIC POWER RESEARCH INSTITUTE
Lead Consultant

Washington, DC
1992 – 1993

Developed new models to evaluate small-scale generation and DSM placed optimally in utility transmission and distribution systems.

PACIFIC GAS & ELECTRIC COMPANY

San Francisco, CA

Research and Development Department 1989 – 1991

Developed an economic evaluation method for distributed generation alternatives. The new approach shows that targeted, circuit-specific, localized generation packages or targeted DSM can in some cases be less costly than larger generation alternatives. Developed the evaluation methodology that led to PG&E's installation of a 500KW photovoltaic (PV) facility at their Kerman substation. This is the only PV plant ever designed to defer the need for distribution capacity.

ELECTRIC POWER RESEARCH INSTITUTE Palo Alto, CA
1988 – 1992

Developed the first formal economic model capable of integrating DSM into a transmission and distribution plan; the case study plan was used by PG&E for a \$16 million pilot project that was featured on national television.

DEPARTMENT OF ENERGY Washington, DC
1989 – 1990

Lead consultant on a cooperative research and development project with the People's Republic of China. The final product was a book on lessons learned from electric utility costing and planning in the United States.

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Corporate Planning Department 1989 – 1992

Lead consultant on a joint EPRI and PG&E research project to develop geographic differences in PG&E's cost-of-service for use in the evaluation of capital projects. Developed shared savings DSM incentive mechanisms for utilities in California.

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Rate Department Economist 1981 – 1985

Responsible for the technical quality of testimony for all electric rate design filings. Also responsible for research on customers' behavioral response to conservation and load management programs. The research led to the design and implementation of the first and largest residential time-of-use program in California and a variety of innovative pricing and DSM programs.

Education

STANFORD UNIVERSITY Palo Alto, CA
Ph.D. in Civil Engineering

STANFORD UNIVERSITY Palo Alto, CA
M.S. in Civil Engineering

UNIVERSITY OF CALIFORNIA Berkeley, CA
B.A. in Economics

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