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Commentaires sur la demande tarifaire 2008 d'Hydro-Québec TransÉnergie

Témoignage de Philip Raphals

pour le RNCREQ et UC

R-3640-07

Régie de l'énergie

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1 Qualifications

Quel est votre nom, titre et adresse d'affaires ?

Mon nom est Philip Raphals. Je suis directeur général du Centre Hélios, situé au 326 boul. St.-Joseph est, suite 100, Montréal, Québec, H2T 1J2.

Veuillez décrire le Centre Hélios.

Fondé en 1996, le Centre Hélios est un organisme de recherche à but non lucratif, offrant une expertise indépendante dans le secteur de l'énergie. Le Centre Hélios produit et rend disponibles les connaissances requises pour la mise en œuvre de stratégies, politiques, approches réglementaires et choix économiques favorisant le développement durable et équilibré du secteur énergétique. Depuis 2005, il produit également des analyses approfondies à l'égard des changements climatiques.

Veuillez décrire votre expérience professionnelle.

Mon expérience est résumée dans mon Curriculum vitae. Mes activités professionnelles ont touché à un grand nombre de sujets reliés à la planification, la réglementation et la tarification des réseaux électriques. Ces sujets ont inclus, entre autres, la restructuration des marchés énergétiques, les processus de planification, la réglementation du transport d'électricité, l'efficacité énergétique et la sécurité des approvisionnements dans un réseau hydraulique.

Avez-vous déjà été reconnu comme témoin expert par la Régie de l'énergie ?

J'ai été reconnu par la Régie de l'énergie comme expert :

- en énergie (R-3401-98, R-3398-98 et R-3410-98[1])
- en efficacité énergétique (R-3473-01)
- en coûts évités (R-3519-03)
- en réglementation de transport d'électricité (FERC) (R-3549-04 phase 2 et R-3605-06)
- en impacts environnementaux des filières de production électrique (R-3525-04), et

[1] Dans les deux derniers dossiers, aucune qualification explicite n'a été déterminée par le banc.

- en fiabilité énergétique (R-3470-01 phase 2, R-3518-04 et R-3550-04).

J'ai également déposé des rapports d'expert dans le dossier R-3493-02 (révision de la décision D-2002-95) ainsi que dans le cadre des travaux de la Régie sur la demande du Ministre d'un avis relativement au projet Suroît (R-3526-04).

Avez-vous déjà témoigné sur la tarification du transport d'électricité ?

Oui. Dans le dossier R-3401-98, j'étais l'auteur principal, avec Peter Bradford et feu Ellis O. Disher, d'un rapport d'expert qui explorait en détail plusieurs aspects de la tarification du transport. Ce rapport a été cité maintes fois dans la décision de la Régie. Plusieurs éléments de cette décision découlaient directement de nos recommandations, dont :

- les exigences d'un code de conduite
- le traitement des actifs de télécommunications
- la radiation de projets totalisant 654,7 M $ de la base de tarification
- la méthodologie pour estimer les revenus des ventes à court terme
- la politique de rabais
- le besoin d'une codification des conditions de desserte de la charge locale.

J'ai également fourni un rapport d'expert concernant les tarifs de transport à court terme dans le cadre du dossier R-3493-02, dans lequel Hydro-Québec demandait la révision de la décision D-2002-95. En 2004 et 2005, j'ai témoigné lors des deux phases du dossier R-3549-04, dans le deuxième phase à titre d'expert. Finalement, en 2006, j'ai témoigné à titre d'expert dans R-3605-06.

[5] The request for revision was rejected.

2 Mandat

Veuillez décrire le mandat que vous a donné le RNCREQ et UC.

Le RNCREQ et UC m'ont demandé d'analyser la proposition du Transporteur et de faire toute recommandation qui en découle sur les questions suivantes :

1) Les tarifs de court terme et les rabais, notamment sur l'opportunité de modifier les services de court terme offerts par exemple par l'ajout d'un tarif horaire en pointe ou d'un tarif « wheel through »;

2) Les modalités du compte d'écart pour les revenus des services de point à point;

3) Les implications pour la réglementation du Transporteur de l'Ordonnance 890 de la FERC; et

4) Les modifications nécessaires à la méthode d'allocation des coûts, pour résoudre les contradictions inhérentes à la décision D-2006-66.

Étant donné le temps très limité pour la préparation de ce rapport, il a été convenu qu'il serait rédigé en anglais.

3 Short-term point-to-point tariffs and discounts

3.1 Hourly rates

In R-3549-04, phase 2, I presented testimony recommending modifying the list of point-to-point services offered by TransÉnergie to include separate off-peak and on-peak hourly services. In its decision D-2006-66, the Régie deferred action on this and other related issues until such time as the working group on short-term rates and discounts had finished its work.

This section summarizes and expands upon my prior testimony.

In its decision D-2002-95 in TransÉnergie's first rate case (R-3401-98), the Régie chose to base short-term point-to-point rates on 1-CP, rather than on 12-CP as they were in Reg. 659. This resulted in reducing short-term rates substantially.

In R-3493-02, TransÉnergie sought revision of this decision, arguing that this would lead to a significant loss of annual long-term reservations, and hence to a loss of point-to-point revenues. [5] This did indeed occur. HQP failed to renew 90% of its long-term reservations, and by 2004 total point-to-point revenues had fallen by 69%. Even with the increase in point-to-point services forecast in 2008, total point-to-point revenues for 2008 will be just 2/3 of their 2001 level.[6] Most of HQP's exports are now carried out under hourly service.

In R-3493, I agreed that reducing short-term rates could well result in a significant loss of point-to-point revenues.[7] I recommended that the next rate case explore the possibility of establishing on- and off-peak hourly rates, in order to recover lost revenues.[8]

TransÉnergie did not file a rate case for the rate years 2002, 2003 or 2004. In its 2005 rate case (R-3549-04 phase 2), it asserted that the reduction in point-to-point revenues was mainly caused by the evolution of day-ahead and hourly markets in neighbouring jurisdictions, as opposed to the reduction in short-term point-to-point rates. Its expert Dr. Orans expressed agreement with this point of view.[9] In reponse to information requests, however, he indicated that he had not attempted to separate the relative contributions of this evolution and of the decline of short-term rates in explaining the shift from longer to shorter term transmission service.[10]

The survey of pricing in other North American jurisdictions provided by Dr. Orans showed that TransÉnergie is unique in offering hourly service at all times based on the daily non-firm rate divided by 24.[11] In all but one of the North American jurisdictions mentioned in his survey that used the open access model, separate rates are offered for on-peak and off-peak hourly service.[12] In each one, the on-peak hourly rate consists of the on-peak daily rate divided by 16, while the off-peak hourly rate consists of the off-peak daily rate divided by 24.

Portland General Electric is a typical example in Dr. Orans' survey. Its monthly, weekly and daily rates are identical for firm and non-firm service. Annual service is offered on a firm basis only; hourly service on a non-firm basis only. **Daily and hourly rates distinguish between on-peak**

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6 $205 million (HQT-11, doc. 2, p. 11), compared to $305 million in 2001.

7 http://www.regie-energie.qc.ca/audiences/3493-02/PreuveInterv3493/Preuve_RNCREQ-16sept02.pdf.

8 Ibid., page 4-5.

9 R-3549-04, phase 2, HQT-4, doc. 3, p. 21.

10 R-3549-04, phase 2, HQT-6, doc. 8, R. 45.2.

11 R-3549-04, phase 2, HQT-6, doc. 8, R. 58.1 and 58.2.

12 These are BPA, Puget Sound Energy, Portland General Electric, Southern Company and Entergy, in the U.S., and SaskPower, Manitoba and New Brunswick, in Canada. The one exception is the B.C. Transmission Company, which uses dynamic pricing based on the differential between the COB and Alberta market prices.

and off-peak periods. On-peak daily rates are equal to the annual rate divided by 301[13], while off-peak daily rates are equal to the annual rate divided by 365. **On-peak hourly rates are equal to the on-peak daily rate divided by 16, while off-peak hourly rates are equal to the off-peak daily rate divided by 24.** This approach, commonly known as the **AEP (or "Appalachian") method**, would have resulted in on-peak hourly rates for TransÉnergie of $15.09/MWh, about **80% more than the current hourly rate**.

As Dr. Orans pointed out, **TransÉnergie's short-term rates are consistent with the AEP approach, except with respect to hourly on-peak service**.[14]

In rejecting TransÉnergie's approach to short-term rates in R-3401-98, the Régie stated that "la Régie choisit de se référer à la pratique nord-américaine la plus courante pour la détermination des tarifs de court terme" (D-2002-95, p. 264). Thus, it said, it would base all short-term rates on the annual rate. It did however establish firm and non-firm daily rates, by dividing the annual rate by 260 and 365, respectively.

In D-2002-95, the Régie did not explain its decision not to distinguish between peak and off-peak periods for daily and hourly rates, although, as Dr. Orans' survey shows, this is clearly part of *la pratique nord-américaine la plus courante*. Indeed, dividing the annual rate by 260 reflects the number of working (on-peak) days in the year, not the reservation's firmness. Thus, the Régie in fact diverged, without explanation, from standard practice by applying this rate to *firm* daily service, rather than to *on-peak* daily service. It would thus be entirely consistent with the principle underlying its previous decision D-2002-95 if the Régie were to establish an on-peak hourly rate according to the AEP approach.

In summarizing TransÉnergie's views, D-2002-95 stated:

> Selon le transporteur, cette approche prend en considération le fait que la demande énergétique est tout au long de l'année généralement plus faible le week-end que les jours ouvrables de la semaine et que cela se traduit par une valeur économique du transport moins élevée durant le week-end. (D-2002-95, p. 257)

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[13] Portland General treats Saturday as part of the peak period.

[14] R-3549-04, phase 2, HQT-6, doc. 8, R. 54.3.

This is precisely the justification for charging higher point-to-point rates during peak periods. The problem with HQT's current hourly rate is that it takes a rate designed to reflect the lower value electricity during off-peak periods and makes it available at all times.

When the Régie chose in D-2002-95 to apply AEP off-peak hourly pricing to all hourly service, it did not expect that this would become the vehicle for the vast majority of HQP's point-to-point transmission service.

> **La Régie note l'objectif du transporteur de chercher à inciter les clients à utiliser en priorité les services à plus long terme et de se soucier des impacts possibles sur ses revenus des ventes à long terme.** Toutefois, la Régie considère, comme l'ont signalé certains intervenants, que l'élément incitatif invoqué par le transporteur est déjà pris en compte dans la priorité de renouvellement du service de point à point à long terme et la garantie de la disponibilité des services fermes. La Régie est d'avis qu'il existe un incitatif important pour le client du service de point à point à long terme de préserver sa priorité de réservation détenue en renouvelant ses réservations sur un réseau et des interconnexions de plus en plus sollicitées.
>
> …
>
> Même si une baisse des tarifs de service à court terme pourrait avoir un impact négatif sur les revenus du transporteur provenant des ventes à long terme, ce fait, en soi, ne justifie pas des tarifs de court terme aussi élevés. La Régie n'a pas entendu de preuve sur l'ampleur d'un tel impact et ne peut pas l'estimer.[15] (emphasis added)

According to the Working Group report discussed below, HQP expressed considerable interest in this approach with respect to discounts:

> HQP is of the opinion that the Transmission Provider should seriously consider offering two types of rebates, one applicable to on-peak reservations and another to off-peak reservations.[16]

This same logic should also apply to regular hourly rates.

In light of the very significant change in transmission strategy by TransÉnergie's principal client, resulting from the reduction in short-term tariffs, I reiterate the recommendation I made in R-3549 phase 2: **that the list of point-to-point services offered by TransÉnergie should be modified to distinguish between peak and off-peak hourly periods, with rates sets according to the AEP**

[15] D-2002-95, pp. 264-265.

[16] Report by the Task Force on Discount Policy and Ancillary Services for Point-to-Point Transmission Services, p. 22.

method. This would be methodologically appropriate and would constitute an effective step to respond to the decline in point-to-point revenues.

3.2 The Working Group report

In D-2006-66, the Régie decided to create a working group on short-term rates and discounts, and to defer consideration of all proposals with respect to short-term rates until after the working group had tabled its report.

The working group in fact did not address short-term rates at all, preferring to focus its attention on TransÉnergie's discount policy.[17]

In the Working Group, HQD and HQT rightly insisted on the importance of avoiding "free riders" (*transactions opportunistes*); i.e., to ensure that transactions that would have taken place at full price were not replaced with discounted transactions, which would result in a reduction in point-to-point revenues and a corresponding increase in the cost borne by Native Load. This is what happened prior to D-2002-95, when TransÉnergie offered discretionary discounts and a large proportion of HQP's exports took place under heavily discounted transmission tariffs.[18]

As I have explained in R-3401-98 and again in R-3549-04 phase 2, HQP has little choice but to export its hydraulic surplus. While the point-to-point tariff might make it uneconomical to do so during periods when market prices are relatively low and thus may affect the timing of these sales and/or their profitability, one way or another, this surplus energy will eventually be exported and the transmission tariff paid. HQP is thus a captive client for point-to-point services with respect to its hydraulic surplus.

At the same time, HQP also purchases power for resale. If the transmission tariff is prohibitively high, these transactions will be discouraged. As these transactions bring new point-to-point revenues, it is in the interest of TransÉnergie and its clientèle that they take place.

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[17] HQT-14, doc. 10, p. 22-23, R5.4 and 5.4.1.

[18] R-3401-98, Hydro-Québec's Revised Application for the Modification of Rates for the Transmision of Electric Power, Testimony of Philip Raphals, Peter Bradford And Ellis O. Disher on behalf of the RNCREQ (February 7, 2001), chapter 3, pages 11-22.

In R-3549-04 phase 2, the approach proposed by TransÉnergie was based on the differential between market prices in exporting and importing regions. However, as I indicated at the time, this approach would have resulted in significant « free-ridership » on the part of HQP and thus a substantial loss of income for TransÉnergie. It is therefore encouraging to see that TransÉnergie now considers avoiding loss of revenue through « free riders » to be a fundamental consideration with respect to its discount policy.

Because HQP counts for such a large proportion of TransÉnergie's point-to-point revenue and because a significant proportion of HQP's exports are for all intents and purposes unavoidable, it is not possible to offer significant discounts across the board without reducing overall point-to-point revenues. For this reason, the Régie has been wise to suspend all discounts until such time as a truly viable solution can be found.

In this sense, the OPG proposal, supported by BÉMI and other members of the Working Group to apply discounts selectively to wheel-through transactions is worthy of careful consideration. Wheel-through transactions represent one realm where a significant increase in use is possible, and where the risk of free-ridership is low.

HQP and TransÉnergie object that such an approach would represent inadmissible discrimination, given s. 49, para. 1, subparagraph 11 of the *Act sur the Régie de l'énergie*. It is not obvious why the requirement that rates be uniform throughout the territory (postage-stamp rates) should prevent the Régie from establishing different rates, or different discounts, for transactions originating within or outside of Quebec. **This is a point of law that must be resolved before proceeding further with regard to a discount policy.**

At the same time, it should be noted that the wheel-through proposal would do nothing to increase the incentives for buy-resell transactions on the part of HQP. However, while the level of these transactions should in theory be sensitive to the point-to-point transmission tariff, evidence to the contrary was presented to the Working Group by HQP. In response to a survey of Working Group members, HQP reported that a 50% reduction in the point-to-point tariff (to $4/MWh) for all hours during April, May and October 2006 would have had no impact whatsoever on its transmission usage during those periods.[19] It would thus appear that the current tariff level does not represent a significant constraint on buy-sell transactions for HQP.

[19] Appendix 5.

As there is little evidence that the quantity of wheel-out transactions by clients other than Hydro-Québec is likely to grow substantially under the current regulatory regime, the wheel-out approach appears at this time to be the best option for increasing point-to-point revenues through discount policy — assuming, that is, that it is found to be compatible with the *Act.*

In closing, it should be noted once again that short-term rates and discount policy are deeply interrelated. Should the Régie accept our proposal to set peak and off-peak hourly rates according to the standard AEP method, the advantages and disadvantages of discounts will have to be re-evaluated.

4 Modalities of the *compte d'écart* point-to-point revenues

4.1 Background (R-3605-06)

In R-3605-06, I presented testimony on the adequacy of the demand and revenue forecasts, including both Native Load and point-to-point service. I recommended applying a *post facto* true-up mechanism, to ensure that the transmission charges to HQD are just and reasonable.

In that same hearing, interveners ACEF de Québec, OC and AQCIE/CIFQ also questioned the validity of HQT's forecasts. AQCIE/CIFQ proposed the creation of a *compte d'écart* that would account for any difference between forecast and actual revenues from short-term point-to-point sales.

In my testimony in R-3605-06, I proposed two alternatives. The simpler of the two consisted of simply crediting (or debiting) to HQD the difference between forecast and actual point-to-point revenues, by means of an *écriture règlementaire.*

> **En principe, il suffirait de créditer au Distributeur à la fin de l'année tout montant perçu par le Transporteur en services de point à point au-delà de ses prévisions, ou de le débiter pour des revenus manquants.** En fait, étant donné que le Distributeur et le Transporteur font partie de la même compagnie intégrée Hydro-Québec, une écriture réglementaire suffirait pour régler ces écarts.[20] (bold type in original)

The second, more complex, approach involved adjusting the tariff calculations based on actual values. One consequence of this approach would be to modify the base tariff ($/kW), which should,

[20] R-3605-06, RNCREQ, Réponse à la Demande d'information no 1 de la Régie (25 octobre 2006), page 2.

in theory, also affect the long-term point-to-point rate. However, I suggested that it would not be advisable to attempt to modify the long-term point-to-point rate retroactively:

> Cet écart ne peut être récupéré sans rendre le tarif de point à point long terme provisoire, voir le modifier rétroactivement. Une telle rétroactivité n'est ni nécessaire ni justifiable dans l'espèce, étant donné que les clients de service de point à point prennent des décisions d'affaires en fonction du tarif — ce qui n'est pas le cas pour le Distributeur.[21]

In its decision D-2007-08, the Régie adopted the approach of a *compte d'écart*, because the actual revenues from point-to-point service depend on many factors outside the control of TransÉnergie and its clients.

The Régie indicated that the *compte d'écart should* include not only the revenues from short-term point-to-point service, but also from long-term service.

> Ce compte devra englober les revenus des services de point à point de long terme et de court terme. **Bien que ce soit les aléas des revenus du service de point à point de court terme qui justifient l'instauration d'un compte d'écart, des transferts de revenus significatifs entre les services de point à point de long terme et de court terme ont été observés dans le passé et peuvent encore survenir**[22]. (bold added)

At the same time, it required that the account be distributed between native load and long-term point-to-point clients, though it did not specify its reasoning for this choice.

> **Les écarts tant positifs que négatifs seront cumulés en vue de les répartir entre les clients de la charge locale et les clients du service de point à point de long terme.** Le solde du compte portera intérêt au coût moyen pondéré du capital du Transporteur. Les modalités de disposition du compte seront établies à l'occasion du prochain dossier tarifaire[23]. (bold added)

Finally, the Régie indicated that it did not accept the RNCREQ's proposal, based on my testimony, with respect to billing for Native Load, because discussion of modification of the rate structure had been excluded from R-3605-06 :

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[21] Ibid., p. 11-12.

[22] D-2007-08, p. 63 à 64.

[23] D-2007-08, p. 63 à 64.

> La proposition du RNCREQ repose sur une facture variable pour la charge locale et entraînerait, par conséquent, une modification de la structure tarifaire, sujet qui a été exclu dans le présent dossier[24].

4.2 HQT's proposal

HQT's proposal concerning the disposition of the *compte d'écart* is found in HQT-4, doc. 3.

According to HQT's proposal, the difference between projected and actual point-to-point revenues is determined based on figures in Hydro-Québec's annual report. (An estimate based on 4 months' actual data would be included in the rate filing.) The balance is distributed *pro rata* among Native Load, long-term point-to-point and network integration clients. HQT advises its clients of any adjustment within 30 days of the filing of the Annual Report, and interest is charged on any amount owed as of the 31st day.[25]

HQD proposes that HQD's contribution set out in Attachment H of the OATT remains unchanged, and that the charge (or credit) resulting from the *compte d'écart* be made through a separate *écriture comptable*.[26] For long-term point-to-point clients, an additional charge will be invoiced, or a credit reimbursed.

HQT's proposal thus adheres closely to the Régie's instructions. The proposed timing for determining and paying (crediting) the resulting amounts effectively results in minimizing interest charges – though allowing 30 days from the *billing date* before interest charges are applied would be more respectful of normal business procedures.

4.3 Discussion

4.3.1 Retroactive adjustment of long-term point-to-point rates

According to HQT's proposal, long-term point-to-point rates would be adjusted retroactively, depending on the balance in the *compte d'écart.* However, they would not be characterized as

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[24] Ibid., p. 64.

[25] HQT-4, doc. 3, p. 7-8.

[26] HQT-14, doc. 6, p. 14, R. 8.2.

provisoire, though the OATT would indicate that they could be modified retroactively.[27] This is essentially a semantic distinction. Unlike all other point-to-point clients, a client who subscribes to long-term point-to-point service could not be certain that the rate posted on OASIS was in fact the rate it would ultimately have to pay. The rate adjustment could take place more than a year after the original transaction was executed on OASIS.

In the example provided by HQT, if point-to-point revenues in 2007 remain (as currently projected) $42 M greater than the levels used in D-2007-08, a refund of 1,8% ($0,7 M / $40 M) would be made to long-term point-to-point customers.

If, however, point-to-point revenues had been lower than forecast, long-term customers would have to make an additional payment for the service they had already purchased and used. In an extreme case where short-term point-to-point revenues fell to $25 million with no corresponding increase in long-term revenues, the additional retroactive charge to long-term customers would be 3% of the amount originally paid.

While this amount is not exorbitant, it is worth asking to what extent this price uncertainty might discourage clients from taking long-term service. It is not in the interest of either HQT or its customers to further accentuate the shift from long-term to short-term service that we have seen in recent years.

More important, however, on the conceptual level, is the disruption this change makes to the overall economy of TransÉnergie's open access transmission tariff. A fundamental aspect of the structure of the *Terms and Conditions,* derived directly from FERC's *pro forma* tariff on which it was based, is the distinction between categories of client that bear responsibility for a share of the Transmission Provider's revenue requirement (native load and network integration customers), and those that purchase a service at a fixed price (point-to-point customers).

In establishing a retroactive modification of a point-to-point price, the basic architecture of the open access tariff is modified. I am not aware of any Transmission Providers whose point-to-point rates are subject to retroactive modification many months after the transaction has been executed and several months after the service has been provided.

Retroactive modification of long-term point-to-point rates to dispose of the *compte d'écarts* also creates an unusual feedback loop with respect to these rates. Thus, differences between forecast and

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[27] HQT-14, doc. 10, p. 8, R 2.2 and HQT-14, doc. 1, p. 10, R 6.1.

actual revenues from long-term customers are, in part, recovered from or returned to these same customers.

For all these reasons, I would urge the Régie to reconsider its decision in D-2007-08 to include long-term customers in the disposition of this account. Given the close similarity between long-term and short-term service, already recognized by the Régie in the passage quoted above, my recommendation is to *include* long-term service in calculating the *compte d'écart,* but to exclude it from the distribution.

4.3.2 Relying on HQD's forecast load for ratemaking purposes

The Régie's decision to limit the application of the *compte d'écart* to variations in point-to-point revenues means that, while the amount paid for transmission service by HQD will, in the end, reflect actual (as opposed to forecast) revenues from point-to-point service, it will continue to be based on HQD's *forecast* loads, as opposed to its actual loads.

As noted above, the Régie declined to consider this option in R-3605 because the procedural decision D-2006-126 had excluded any modification of the rate structures from the scope of the hearing.

My testimony in R-3605-06 demonstrated that the HQD load forecast was not sufficiently detailed to meet the criteria set out in D-99-120 (R-3405-98), in which the Régie adopted the projected test methodology:

> À l'égard de l'utilisation de l'année témoin projetée, Hydro-Québec devra, et ce pour toute requête tarifaire visant l'établissement de tarifs de transport d'électricité, **démontrer le fondement des hypothèses et des prévisions soumises à la Régie**. À cette fin, Hydro-Québec devra être en mesure **d'expliquer chacune des prévisions sur la base des données réelles**.[28] (bold added)

While HQT indicated in R-3605-06 that, the Régie could always judge the validity of its forecasts and adjust them,[29] the fact remains that the Régie has not to date disposed of sufficient information in a transmission rate case to justify using these forecasts as a basis for setting definitive rates.

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[28] R-3405-98, D-99-120, p. 13.

[29] Quoted in D-2007-08, p. 63.

If, in accordance with my recommendation above, the Régie chooses not to allow retroactive modification of long-term point-to-point tariffs, there is no point in recalculating the unit cost of transmission ($/kW) based on actual needs. However, should the Régie maintain its decision in D-2007-08 whereby long-term point-to-point rates are adjusted retroactively, it would be logically inconsistent not to also take into account the actual transmission needs of Native Load.

Under the ratemaking methodology in effect since R-3401-98, the residual revenue requirement is shared between Native Load and long-term point-to-point customers on a *pro rata* basis, determined by way of the *tarif annuel,* expressed in $/kW:

> tarif annuel = revenus requis résiduels / (besoins charge locale + besoins point à point long terme)

Until now, the annual tariff has been based on forecast values for all of these parametres. Now, however, under the solution retained in D-2007-08, the value for long-term point-to-point service is in effect being "trued up" based on actual (as opposed to projected) values.[32] As it is the ratio between the transmission needs for these two functions that determines their relative share of the residual revenue requirement, it is inconsistent to "true up" one element but not the other.

Under the current ratemaking structure:

a) reducing long-term point-to-point service increases the share of the residual revenue requirement borne by native load (and vice versa), and

b) reducing native load increases the price for long-term point-to-point service (and vice versa).

Under the approach proposed in D-2007-08, relationship a) is adjusted based on actual values, but relationship b) is not.

This asymmetry is difficult to justify. If the Régie is willing to accept the retroactive modification of long-term pricing, it should, to be consistent, base that correction on the

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[32] While the calculations with respect to the *compte d'écart* of D-2007-08 are not described in these terms, the effect is essentially the same.

actual (as opposed to forecast) relation between native load and long-term point-to-point needs. This would have the additional benefit of providing an incentive to HQD to reduce its *actual* (as opposed to forecast) peak loads, which is not currently the case.

5 FERC Order 890 and its implications for transmission regulation in Québec

While TransÉnergie's original open access tariff, Hydro-Québec Règl. 659, was directly borrowed from FERC's *pro forma* tariff, many significant changes have since been made to it. At the same time, FERC's requirements for utilities under its jurisdiction have changed substantially, most notably with Order 890, adopted in February 2007.

In our testimony in R-3401-98, we reviewed the origins of Règl. 659 and the driving forces behind the establishment of an open access transmission tariff in Quebec.[33] The relevant section from this testimony is attached as Appendix A.

In section 5.1, we will discuss the potential interest the Régie may have in recent developments at FERC, especially Order 890.

In section 5.2, we will briefly review the evolution of FERC's *pro forma* tariff, from Order 888 through Order 2000 to Order 890.

In section 5.3, we will summarize the key findings of Order 890 with respect to the need for reform of the *pro forma* tariff and the reforms it institutes.

In section 5.4, we will make some comments and recommendations with respect to the implications of Order 890 for the regulation of transmission service in Quebec and for the Régie.

[33] Raphals, Bradford and Disher, chap. 3 (see note 18).

5.1 The relevance of Order 890 for transmission regulation in Québec

The potential interest that TransÉnergie and the Régie may have in Order 890 can be broken down as follows:

1. Insofar as TransÉnergie's open access tariff has been recognized by FERC as meeting its reciprocity requirements, it may be obliged to modify its OATT in accordance with Order 890 in order to maintain that recognition;

2. Insofar as a third party has obtained benefits due to FERC's recognition that TransÉnergie's open access tariff is in conformity with FERC's requirements, it may wish to see TransÉnergie's OATT modified in accordance with Order 890 in order to maintain those benefits.

3. Insofar as Order 890 identifies flaws in the open access regime created by the *pro forma* tariff of Order 888 on which TransÉnergie's open access tariff was originally modelled and implements changes to alleviate these flaws, the Régie may wish to determine whether similar flaws exist in its own open access regime and, if so, take inspiration from FERC's improvements.

We will address these three questions in turn.

5.1.1 FERC's reciprocity requirements

In Order 888, FERC recognized that, while it did not have the authority to require utilities not under its jurisdiction to open access to their transmission systems, it did have the ability to ensure that its order did not result in a competitive disadvantage to public utilities obliged to respect its provisions.

For this reason, FERC included a reciprocity provision in section 6 of the *pro forma* tariff, which allows utilities not under its jurisdiction to make use of open access tariffs only if they provide similar access to their own transmission systems. This reciprocity condition can be satisfied in one of three ways :

> **First**, it may provide service under a tariff that has been approved by the Commission under the voluntary "safe harbor" provision. A non-public utility using this alternative submits a reciprocity tariff to the Commission seeking a declaratory order that the proposed reciprocity tariff substantially conforms to, or is superior to, the <u>pro forma</u> OATT. The non-public utility then must offer service under its reciprocity tariff to any public utility whose transmission service the non-public utility seeks to use. **Second**, the non-public utility may

> provide service to a public utility under a bilateral agreement that satisfies its reciprocity obligation. **Finally**, the non-public utility may seek a waiver of the reciprocity condition from the public utility [footnote: See Order No. 888-A at 30,285-86.].[34] [bold added]

Asked which of these three prongs applies to Hydro-Québec, TransÉnergie responded :

> Hydro-Québec offre le service de transport sur son réseau en fonction d'un « OATT » (les *Tarifs et conditions)* qui a été déposé à la FERC.[35]

While this response suggests that it is the first of the three, it does not make any mention of a declaratory order that TransÉnergie's *Tarifs et conditions* substantially conform to, or are superior to, the *pro forma* OATT, nor am I aware of any such declaratory order.

Subject to confirmation, it appears that the response makes reference to the various proceedings under docket ER97-851, whereby H.Q. Energy Services Inc. (« HQES ») sought and obtained Market Based Rate Authorization.[36] As we noted in our testimony in R-3401-98 (App. A, p. 5), Règl. 659 was filed with FERC as part of HQES' Market Based Rate application.

It is not clear if, or when, the *Tarifs et conditions* currently in force was submitted to FERC. The most recent substantive comment by FERC on an HQES application dates from May 2005, when FERC wrote as follows :

> 22. H.Q. Energy states that it cannot exercise transmission market power. H.Q. Energy states that the affiliated transmission assets in Quebec and the United States owned by Hydro-Québec and TransÉnergie are either governed by open access provisions or operate under special arrangements approved by the Commission and do not allow H.Q. Energy or its affiliates to exercise transmission market power.
>
> 23. The Commission has clarified that its concerns are more limited for foreign transmission-owning entities than for transmission-owning entities in the United States. The Commission has further stated that its concern is not transmission service to serve Canadian loads — it is transmission to serve United States load. The Commission expanded its concern to include access for United States competitors into Canadian markets on a reciprocal basis. Thus, the Commission seeks to assure reciprocal service into and out of Canada when Canadian entities seek access to United States markets, but the Commission is not seeking to open

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[34] Order 890, paragraph 163.

[35] HQT-14, doc. 10, p. 22, R5.3.

[36] HQES describes itself in documents filed with FERC as « a wholly owned indirect subsidiary of Hydro-Québec » (e.g. FERC submittal 20031114-0168). It is not listed in the organigram of « Participations — 1^{e} et 2^{e} rang » filed as part of HQT-2, doc. 1.

> intra-Canada electric markets through the imposition of open access tariffs for transactions wholly within Canada.
>
> 24. Therefore, the Commission requires an entity that seeks market-based rate authority but has a Canadian affiliate owning transmission facilities to demonstrate that its affiliate offers non-discriminatory access to those transmission facilities that competitors of the Canadian seller can use to reach United States markets. **The Commission has previously found that Hydro-Québec's transmission tariff and TransÉnergie's transmission arrangements meet the standard that the Commission requires for open access transmission services under our jurisdiction. The Commission notes that the terms and conditions of those companies' transmission services are virtually identical to the Commission's *pro forma* tariff in all material respects. The main difference is that while the *pro forma* tariff refers to the Commission as the applicable regulatory agency, their tariffs refer to the Régie. Similarly, the tariffs substitute Canadian law for United States law - *e.g.* Canadian commercial law in lieu of the Uniform Commercial Code**.[37] [underlining and bold added, footnotes omitted]

The original finding that "TransÉnergie's transmission arrangements meet the standard that the Commission requires for open access transmission services under our jurisdiction" dates from the initial proceeding. FERC's description of the TransÉnergie tariff as "virtually identical to the Commission's *pro forma* tariff in all material respects" and its summary of main differences — which fails to mention any of the modifications made by the Régie since 2001 — tends to suggest that FERC's judgement was based on Règl. 659 rather than on the current version of the *Tarifs et conditions.*

Furthermore, it should be pointed out that, according to Order 890, any non-jurisdictional utility that does benefit from a so-called safe-harbor tariff has a mandatory obligation to amend it in conformity with Order 890. This does not appear to be the situation of TransÉnergie.

It thus appears that TransÉnergie satisfies FERC's reciprocity provision on a bilateral basis with neighbouring systems, whether by agreement (prong 2) or by waiver (prong 3). If this is true, then the obligatory modification of the OATT mentioned in para. 191 of Order 890 would not apply to TransÉnergie.[38]

> **191.** We will also retain Order No. 888's three alternative provisions for satisfying the reciprocity condition, i.e.: a non-public utility that owns, controls, or operates transmission and seeks transmission service from a public utility must either satisfy its reciprocity obligation under a bilateral agreement, seek a waiver of the OATT reciprocity condition

[37] FERC, Docket Nos. ER97-851-012, ER97-851-013 and ER97-851-015, H.Q. Energy Services (U.S.) Inc., Order Accepting Updated Market Power Analysis, May 26, 2005 (111 FERC ¶ 61,255).

[38]

> from the public utility, or file a safe harbor tariff with the Commission. **Thus, for non-public utilities that choose to use the safe harbor tariff, its provisions must be substantially conforming or superior to the revised pro forma OATT in this Final Rule. A non-public utility that already has a safe harbor tariff must amend its tariff so that its provisions substantially conform or are superior to the revised pro forma OATT if it wishes to continue to qualify for safe harbor treatment.** As the Commission stated in Order No. 888-A, a non-public utility may limit the use of its voluntarily offered safe harbor reciprocity tariff only to those transmission providers from whom the non-public utility obtains open access service, as long as the tariff otherwise substantially conforms to the pro forma OATT. **We reiterate that these reciprocity requirements apply equally to all non-public utility transmission providers, including those located in foreign countries**. [bold added]

5.1.2 Third-party benefits

As mentioned above, H.Q. Energy Services (U.S.) Inc. holds a Market Based Rate authorization, which was obtained in part based on the conformity of TransÉnergie's open access tariff then in effect with the *pro forma* tariff of Order 888. HQES may thus have an interest in ensuring that TransÉnergie's tariff be modified to meet the requirements of Order 890.

Should that be the case, however, it can be expected that HQES would request that TransÉnergie so modify its tariff. It is not up to either TransÉnergie or the Régie to proactively look after the interests of individual affiliated or unaffiliated companies.

5.1.3 Improving Québec's open access regime

It thus appears that, for the moment at least, TransÉnergie is under no direct or indirect obligation to modify its tariff in conformity with Order 890. However, the issues addressed in the rulemaking proceeding that led to this Order — the potential shortcomings of open access transmission tariffs like TransÉnergie's — are potentially of great concern to the Régie.

5.2 Background

In order to properly situate Order 890 in the evolution of FERC's regulation of transmission providers, it is useful to review briefly the events that preceded it.

Order 890 is the Final Order in a ratemaking proceeding entitled, « Preventing Undue Discrimination and Preference in Transmission Service ». This proceeding was the first thoroughgoing review of Order 888, the order that created open access transmission service in the United States. A partial review was undertaken in the proceeding concerning Regional Transmission Organizations (docket RM99-2), which led to Order 2000.

5.2.1 Order 888

The key driver behind the events described below was the adoption by the U.S. Congress of the Energy Policy Act of 1992 (EPAct). This landmark legislation mandated FERC to create conditions which would allow a competitive market in electricity generation to flourish while allowing the states to decide whether to allow customer choice at the retail level. At the same time, the new law recognized that drastic changes in the way the transmission system is managed would be fundamental to the establishment of such a market.

At the heart of FERC's efforts to create a competitive wholesale power market in the U.S. is Order 888, issued in 1995. Order 888, the result of a rulemaking process entitled *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*, was predicated on the understanding that the primary impediment to the development of a fully competitive market in electric energy was the ability of vertically integrated utilities to use their control over their transmission systems to hinder transactions that were not in their interests (or not in the interests of their marketing subsidiaries or affiliates). Order 888 required utilities to offer open access to their transmission systems, at non-discriminatory rates and conditions, and required "functional separation" (at a minimum) between their transmission and energy marketing functions.

FERC judged that such functional unbundling would be adequate to create confidence on the part of other users of the transmission system that they were being treated fairly and that the transmission operator could not unduly favour its own marketing affiliates at the expense of other users. At the same time, FERC favoured, but did not require, the creation of Independent System Operators (ISO). An ISO is a non-profit organization that controls and operates, but does not own, a transmission system.

In rejecting demands that vertically integrated utilities be broken up, FERC took a calculated risk — that these halfway measures would be good enough to allow competition to take root.

5.2.2 Order 2000

Order 888 did in fact result in an explosion of restructuring activity, but it gradually became clear that vertically integrated utilities were still able to use their control over transmission lines to their own advantage. In response, FERC began in 1999 the rulemaking process which led to the issuance of Order 2000.

In Order 2000, FERC acknowledged that Order 888 was not entirely successful, and that there remain significant barriers and impediments to fully competitive electricity markets. The Order strongly favoured the creation of "regional transmission organizations" (RTOs), regional bodies that would control and operate the transmission systems of the utilities located within their territories, while remaining independent of control by any company that generates or sells power. The intent was to ensure that the transmission system — the most critical element to a truly competitive market — could not be used to favour the interests of its owners and their affiliates.

5.2.3 Order 890

Following Order 2000, it gradually became clear that RTO's were not likely to develop in most parts of the United States, and so would not constitute a viable remedy to the problems identified with respect to the open access transmission regime. In May 2006, FERC initiated a major rulemaking proceeding to revise the Open Access Transmission Tariff required under Order 888, which eventually resulting in the filing of some 6,500 pages of comment by almost 300 parties. The final rule, Order 890, was issued in February 2007. FERC described the need for this process in the following words:

> **26.** Although Order No. 888 has been successful in many important respects, the need for reform of the Order No. 888 *pro forma* OATT has been apparent for some time. **In 1999, the Commission held, in adopting Order No. 2000, that the *pro forma* OATT could not fully remedy undue discrimination because transmission providers retained both the incentive and the ability to discriminate against third parties, particularly in areas where the *pro forma* OATT left the transmission provider with significant discretion.** The Commission made a similar finding in Order No. 2003, holding that opportunities for undue discrimination continue to exist in areas where the *pro forma* OATT leaves transmission providers with substantial discretion. The NOPR reaffirmed these findings, preliminarily concluding that **opportunities for undue discrimination continue to exist in the provision of open access transmission service**[39].

[39] Order 890, para. 26, p. 22.

The main reforms set forth in Order 890 include:

- mandatory procedures for calculating Available Transmission Capacity, in order to reduce the possibility of undue discretion in favour of the transmission providers' affiliates,
- coordinated, open, and transparent transmission planning required on both a local and regional level,
- a number of measures were included to reduce barriers for intermittent resources, such as wind power, and
- penalties were increased, in order to strengthen compliance.

At the same time, many of the fundamental elements of Order 888 were retained, including:

- functional separation as an alternative to divestiture of generating facilities,
- FERC's exclusive jurisdiction over the rates, terms and conditions of unbundled retail transmission in interstate commerce, but not over bundled retail transmission,
- Native Load protection, and
- the types of transmission service offered.

In the following sections, where FERC's comments are self-explanatory, we will simply cite relevant passages from Order 890.

5.3 Problems identified with respect to the Order 888 OATT and reforms adopted

While the underlying purpose of Order 888 was to allow third parties' to use utilities' transmission grids in the same way as the utilities themselves use them, FERC acknowledged in Order 890 that opportunities for undue discrimination continue to exist. Similar findings had been made in Order 2000 and in Order 2003.

Discriminatory behaviour of various types had been identified by commenters, including:

- Inability to challenge a denial of transmission service on a timely basis, even if the OASIS showed Available Transmission Capacity,

- Instances where competitors had been granted transmission access, even though OASIS showed zero Available Transmission Capacity,
- Abusive use of discretion to favour the transmission provider's merchant function,
- Lack of transparency in requesting, scheduling and interrupting service

FERC concluded that the wide discretion available to transmission providers under the OATT, combined with their incentive to discriminate, creates real opportunities for discrimination under the OATT, and that the only appropriate avenue for resolving these problems was through a rulemaking, rather than through case-by-case decisions:

> 42. It is thus clear to us that, notwithstanding the Commission's efforts in Order No. 888, opportunities to engage in undue discrimination can and will persist unless the existing *pro forma* OATT is reformed. We therefore exercise our broad remedial authority today to limit these remaining opportunities for undue discrimination. The Commission concludes that any additional costs incurred by transmission providers to implement the reforms required in this Final Rule are fully justified by the need to ensure open, transparent and non-discriminatory access to transmission service. **We also believe it is appropriate to adopt these reforms by rulemaking, rather than rely on complaints filed by transmission customers or other parties. Case-by-case application of the reforms adopted in this Final Rule would be inappropriate since the most fundamental problems addressed here arise from deficiencies in the *pro forma* OATT itself, not simply the implementation of the *pro forma* OATT by a few transmission providers.** Also, we decline to establish a one-year review period for the reformed *pro forma* OATT, as EPSA recommends.[40]

5.3.1 Lack of transparency

FERC found that the *pro forma* OATT failed to create sufficient transparency, and that this lack of transparency undermines confidence and impedes enforcement. It took a number of steps to increase transparency with respect to ATC calculations, planning processes, and other matters, including the designation of network resources.

> <u>*Problems identified*</u>
>
> **51.** The Commission concludes that inadequate transparency requirements, combined with inadequate compliance with existing OASIS regulations, increases the opportunities for undue discrimination under the *pro forma* OATT and makes instances of undue discrimination more difficult to detect. We find that the reforms we adopt in this Final Rule

[40] Bold type in this and subsequent citations from Order 890 has been added by the author.

will improve transparency in the OATT, reduce opportunities for undue discrimination, and increase our ability to detect undue discrimination.

Reforms

88. Increases in transparency to lessen the opportunities to discriminate and reduce transaction costs. In addition to the increased transparency we require regarding the calculation of ATC and transmission planning, we increase the transparency of transmission service provided under the *pro forma* OATT in several other respects. For example, we require transmission providers and their network customers to use the transmission providers' OASIS to request designation of a new network resource and to terminate the designation of an existing network resource. In addition, we require transmission providers to modify their OASIS so that requests to designate and terminate a network resource can be queried, allowing all parties access to such information. We also require transmission providers to post a list of their current designated network resources and all network customers' current designated network resources on their OASIS. Finally, we require transmission providers to post on OASIS all their business rules, practices and standards that relate to transmission services provided under the *pro forma* OATT.

5.3.2 Transmission planning

FERC imposed mandatory open planning processes to ensure that transmission planning does not favour affiliated generators over others. The planning processes are judged under nine criteria: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, congestion studies and cost allocation for complex projects.

Problems identified

57. The Commission concludes that reforms are needed to ensure that transmission infrastructure is evaluated, and if needed, constructed on a nondiscriminatory basis and is otherwise sufficient to support reliable and economic service to all eligible customers. …

61. The decline in transmission investment and increase in transmission congestion underscore our concerns over inadequate planning provisions of the existing *pro forma* OATT. The existing *pro forma* OATT, as indicated above, contains very little specificity regarding how transmission planning should be conducted, how customers' needs are incorporated into that process, and what information is publicly available regarding the transmission providers' assumptions, criteria and data used in the planning process. **These inadequacies are sufficiently severe, standing alone, to merit reform of the OATT.** However, they are of even greater concern given the current state of the transmission grid. With inadequate levels of investment in the grid and increasing transmission congestion, customers' ability to access alternatives to the transmission provider's resources is limited. It is therefore imperative for the Commission to ensure that the planning process under each transmission provider's OATT is sufficient to prevent undue discrimination and transparent enough to detect any remaining instances of undue discrimination. We have done so in the reforms adopted and explained in section V.B.

424. The existing *pro forma* OATT does not counteract these incentives in the planning area because there are no clear criteria regarding the transmission provider's planning obligation. **Although the *pro forma* OATT contains a general obligation to plan for the needs of their network customers and to expand their systems to provide service to point-to-point customers, there is no requirement that the overall transmission planning process be open to customers, competitors, and state commissions. Rather, transmission providers may develop transmission plans with limited or no input from customers or other stakeholders. There also is no requirement that the key assumptions and data that underlie transmission plans be made available to customers.**

425. Taken together, this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning. Without adequate coordination and open participation, market participants have no means to determine whether the plan developed by the transmission provider in isolation is unduly discriminatory. This means that disputes over access and discrimination occur primarily after-the-fact because there is insufficient coordination and transparency between transmission providers and their customers for purposes of planning.[41] …

Reforms

426. In order to provide for more comparable open access transmission service, limit the potential for undue discrimination and anticompetitive conduct, and satisfy its statutory responsibilities under section 217 of the FPA, **the Commission proposed to amend the *pro forma* OATT to require coordinated, open, and transparent transmission planning on both a local and regional level. Each public utility transmission provider would be required to submit, as part of its compliance filing in this proceeding, a proposal for a coordinated and regional planning process that complies with the following eight planning principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, and congestion studies.** In the alternative, transmission providers could make a compliance filing in this proceeding describing their existing coordinated and regional planning processes and showing that they are consistent with or superior to that required in the Final Rule.

435. In order to limit the opportunities for undue discrimination described above and in the NOPR, and to ensure that comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, the **Commission concludes that it is necessary to amend the existing *pro forma* OATT to require coordinated, open, and transparent transmission planning on both a local and regional level**. …

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[41] In our discussion of enforcement issues at section **Error! Reference source not found.** of this Final Rule, we note specific situations in which transmission providers have agreed to resolve staff allegations that they engaged in OATT violations involving transactions with affiliates. While these specific situations may not directly relate to discrimination in planning, they nevertheless document the continuing incentive of transmission providers to favor themselves and their affiliates in the provision of transmission service.

440. We also make clear that transmission owning members of ISOs and RTOs must participate in the planning processes adopted in this Final Rule. In order for an RTO's or ISO's planning process to be open and transparent, transmission customers and stakeholders must be able to participate in each underlying transmission owner's planning process. This is important because, in many cases, RTO planning processes may focus principally on regional problems and solutions, not local planning issues that may be addressed by individual transmission owners. These local planning issues, however, may be critically important to transmission customers, such as those embedded within the service areas of individual transmission owners. Consequently, the intent of the Final Rule will not be realized if only the regional planning process conducted by the RTOs and ISOs is shown to be consistent with or superior to the Final Rule. To ensure full compliance, individual transmission owners must, to the extent that they perform transmission planning within an RTO or ISO, comply with the Final Rule as well. …

441. The Commission also expects all non-public utility transmission providers to participate in the planning processes required by this Final Rule. A coordinated, open, and transparent regional planning process cannot succeed unless all transmission owners participate. …

5.3.3 Need for a consistent and transparent method of measuring ATC

FERC will now require transmission providers to explicitly indicate the methodologies used for calculating firm and non-firm Available Transmission Capacity, to ensure that ATC calculations are not used to subtly discriminate against competitors.

Problems identified

62. Another area in which transmission providers have significant discretion under the *pro forma* OATT is the calculation of ATC. While Order No. 888 obligated each public utility to calculate the amount of transfer capability on its system available for sale to third parties, the Commission did not standardize the methodology for calculating ATC, nor did it impose any specific requirements regarding the disclosure of the methodologies used by each transmission provider.[42] As a result, there are a variety of ATC calculation methodologies in use today and very few clear rules governing their use. Moreover, there is often very little transparency about the nature of these calculations, given that many transmission providers have filed only summary explanations of their ATC methodologies in Attachment C to their OATTs.

63. In the NOPR, the Commission noted that, although the industry has sought to pursue greater consistency in ATC calculations through existing NERC processes, these efforts to date have been largely unsuccessful. The Commission expressed its preliminary determination that the lack of a consistent, industry-wide methodology for calculating ATC

[42] Order No. 888 at 31,794 n.610.

gives transmission providers the ability and the opportunity to unduly discriminate against third parties. The Commission therefore proposed a number of reforms to the process of calculating ATC to provide clarity and transparency to users of the grid.

68. We find that the lack of a consistent and transparent methodology for calculating ATC gives transmission providers the ability and opportunity to unduly discriminate in the provision of open access transmission service. There are few clear rules respecting ATC calculation, and transmission providers retain unnecessarily broad discretion in this area. **This resulting discretion is a significant problem because calculation of ATC, which varies greatly depending on the criteria and assumptions used, may allow the transmission provider to discriminate in subtle ways against its competitors.** On systems where transmission capacity is congested, this lack of consistency, coupled with a lack of transparency, is of heightened importance and has led to recurring disputes over whether the transmission provider is exercising its discretion to discriminate against its competitors. This discretion also hampers the detection of undue discrimination and, thereby, undermines the Commission's ability to enforce the general requirement in Order No. 888 that transmission service be provided on a not unduly discriminatory basis.

Reforms

83. Consistency and transparency of ATC calculations. The Commission affirms the finding in the NOPR that the lack of a consistent, industry-wide methodology for calculating ATC, and the lack of adequate transparency in ATC calculations, increases the potential for undue discrimination and also makes undue discrimination more difficult to detect. The lack of consistent standards can facilitate undue discrimination by giving a transmission provider the discretion, and hence the ability and opportunity, to favor itself and its affiliates over third parties in how it calculates and allocates ATC. In this Final Rule, we give the industry specific guidance regarding the calculation of ATC and establish a firm deadline to develop certain requirements to make more consistent the ATC calculation process and the process of exchanging data between transmission providers about ATC. In addition, we amend *pro forma* OATT requirements as well as our OASIS regulations to increase the transparency in how ATC is calculated.

207. The Commission adopts the NOPR proposal to require industry-wide consistency of all ATC components and certain definitions, data, and modeling assumptions. The Commission also will require each transmission provider to include in Attachment C to its OATT detailed descriptions for calculating both firm and non-firm ATC, consistent with the requirements of this Final Rule. The purpose of increasing the consistency and transparency of ATC calculations is to reduce the potential for undue discrimination in the provision of transmission service, specifically by reducing the opportunity for transmission providers to exercise excessive discretion. We find that the amount of discretion in the existing ATC calculation methodologies gives transmission providers the ability and opportunity to unduly discriminate against third parties. In order to minimize this discretion, the Final Rule requires that all ATC components (i.e., TTC, ETC, CBM, and TRM) and certain data inputs, data exchange, and assumptions be consistent and that the number of industry-wide ATC calculation formulas be few in number, transparent and produce equivalent results. The Commission finds that these reforms will facilitate development of a more coherent and uniform determination of ATC.

323. The Commission adopts the NOPR proposal to increase transparency regarding ATC calculations by requiring each transmission provider to set forth its ATC calculation methodology in its OATT. Each transmission provider must, at a minimum, include the following information in Attachment C to its OATT. It must clearly identify which of the NERC-approved methodologies it employs (e.g., contract path, network ATC, or network AFC). It also must provide a detailed description of the specific mathematical algorithm the transmission provider uses to calculate firm and non-firm ATC for the scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule), and planning horizon (beyond the operating horizon). In addition, transmission providers must include a process flow diagram that describes the various steps that it takes in performing the ATC calculation. Furthermore, transmission providers must set forth a definition of each ATC component (i.e., TTC, ETC, TRM, and CBM) and a detailed explanation of how each one is derived in both the operating and planning horizons. **Requiring transmission providers to file a statement of their ATC calculation methodology along with a process flow diagram and more detailed definitions of ATC components in Attachment C of the OATT will provide greater transparency to transmission customers and assist in identifying any discrepancies that may arise in ATC determinations.** These new requirements will assist in alleviating any appearance of discrimination in the determination of ATC.

5.3.4 Discriminatory pricing of energy imbalances

FERC will now require Bonneville-style three-tier imbalance pricing, both for generators and for loads, in which imbalance charges are based on incremental cost and escalate as the imbalance increases. Above ± 1.5% or more of the programmed transfer, settlement is made at 90% / 110% of incremental cost, and above ± 7.5% it is settled at 75% / 125% of the transmission provider's actual incremental cost. Intermittent resources, however, are exempt from this third tier.

TransÉnergie's energy imbalance charges are considerably more severe: 50% / 150%, for all imbalances of ± 1.5% or more of the programmed transfer.

Problems identified

71. In general, transmission customers complain about the level and scope of energy and generator imbalance charges that are levied under the *pro forma* OATT and under individual interconnection agreements. Customers complain that energy imbalance charges are excessive and not related to the actual costs incurred by transmission providers. They also argue that the inconsistency between these charges in different control areas is unnecessary, and that other means of compensating the transmission provider, such as return-in-kind, should be considered. Generators likewise complain that generator imbalance charges are excessive, that transmission providers refuse to credit generators with the revenues resulting from imbalance penalties that are collected, and that transmission providers prevent unaffiliated generators from purchasing or self-supplying generator imbalance services. In addition, owners of intermittent resources complain that generator imbalance charges, which are imposed to provide an incentive for generators to schedule accurately, are inappropriate given their lack of control and ability to cure deviations.

72. The Commission agrees that imbalance charges should provide appropriate incentives to keep schedules accurate without being excessive. We also find that consistency in imbalance charges, both between and among energy and generator imbalances, is preferable to the wide variety of imbalance provisions in place today. All imbalances have the same net effect on the transmission system in that they require other generation to be ramped up or down to compensate for the imbalance. As such, the Commission adopts two *pro forma* OATT provisions (Schedule 4 for energy imbalances and Schedule 9 for generator imbalances) based on a tiered structure similar to the imbalance provision used by Bonneville, as described further below. Such an approach recognizes the link between escalating deviations and potential reliability impacts on the system while keeping imbalance charges closely related to incremental costs. The Commission finds, however, that intermittent resources should be exempt from the highest-tier deviation band. We also require transmission providers to credit to all non-offending transmission customers the revenues they collect in excess of incremental costs.

Reforms

85. … Energy and Generator Imbalance Charges. We find that energy and generator imbalance charges we have previously accepted are excessive, too varied, and otherwise unrelated to the cost of providing the service and, therefore, we reform energy and generator imbalance pricing. We adopt tiered *pro forma* OATT energy and generator imbalance provisions similar to those in use by Bonneville and exempt intermittent resources from the highest deviation band. In these new provisions, imbalance charges are based on incremental cost and escalate as the imbalance increases. Any deviations from these provisions must be consistent with or superior to the *pro forma* OATT as modified by this Final Rule and must meet the following criteria: the charges must (1) be related to the cost of correcting the imbalance, (2) be tailored to encourage accurate scheduling behavior, such as by increasing the percentage of the adder as the deviations become larger, and (3) account for the special circumstances presented by intermittent generators, such as by waiving the higher ends of the deviation penalties.

636. The Commission noted that Bonneville has adopted an energy imbalance pricing approach based on a three-tiered deviation band that appears workable for both energy imbalance service and generation imbalance service. Under this approach, imbalances of less than or equal to 1.5 percent of the scheduled energy (or two megawatts, whichever is larger) would be netted on a monthly basis and settled financially at 100 percent of incremental or decremental cost at the end of each month. Imbalances between 1.5 and 7.5 percent of the scheduled amounts (or two to ten megawatts, whichever is larger) would be settled financially at 90 percent of the transmission provider's system decremental cost for overscheduling imbalances that require the transmission provider to decrease generation or 110 percent of the incremental cost for underscheduling imbalances that require increased generation in the control area. Imbalances greater than 7.5 percent of the scheduled amounts (or 10 megawatts, whichever is larger) would be settled at 75 percent of the system decremental cost for overscheduling imbalances or 125 percent of the incremental cost

for underscheduling imbalances. <u>Intermittent resources are exempt from the third-tier deviation band</u> and pay the second-tier deviation band charges for all deviations greater than the larger of 1.5 percent or two megawatts.

663. In order to increase consistency among transmission providers in the application of imbalance charges, and to ensure that the level of the charges provides appropriate incentives to keep schedules accurate without being excessive, the Commission adopts in the *pro forma* OATT imbalance provisions similar to those implemented by Bonneville. …

702. As stated in the NOPR, the Commission finds that inadvertent energy is not comparable to energy and generation imbalances and, therefore, we will continue to allow inadvertent energy to be treated differently from energy and generation imbalances.

5.3.5 Methods for evaluating requests for long-term firm point-to-point service

Concerned about situations where requests for firm long-term service were rejected because of just a few constrained hours. To ensure that third party users enjoy access to similar to that provided to Native Load, FERC created a new category of "conditional firm" point-to-point service to address the situation where firm service can be provided for most, but not all, hours of the period requested.

<u>*Problems identified*</u>

73. In the NOPR, the Commission examined whether existing methods for evaluating requests for long-term firm point-to-point service continue to be just and reasonable. When a transmission provider considers a new resource to serve native load, the transmission provider does not eliminate an otherwise economic option because the resource may not be deliverable during a few hours of the year. **For transmission customers, however, the transmission provider evaluates whether service can be granted in every hour of the year that is modeled and, if not, it informs the customer that service cannot be provided out of existing transfer capability**. Only if the transmission customer agrees to pay for facilities studies does the transmission provider evaluate redispatch options, including whether they are less expensive than the upgrade costs. The Commission therefore proposed to reform the existing *pro forma* OATT planning redispatch obligation, or, in the alternative, to add a conditional firm service to the *pro forma* OATT. As proposed by the Commission, conditional firm would have been a long-term service allowing the transmission provider to give a lower curtailment priority than firm to the transmission customer during a pre-specified number of hours.

78. The Commission believes it is necessary to modify the manner in which transmission providers assess point-to-point service requests to eliminate the potential for undue discrimination in transmission service. We find that both techniques – planning redispatch and conditional firm service – are currently used under certain circumstances by transmission providers to serve native load and, therefore, that transmission customers should have comparable services in order to avoid undue discrimination, facilitate the provision of long-term transmission service and provide customers with greater flexibility in choosing resources to meet their needs. We expect that both options will help integrate new generation more quickly. This can be particularly beneficial to renewable generation resources, such as wind, that can be constructed more quickly than the transmission upgrades necessary to deliver their power on a firm basis over the long-run.

Reforms

86. Improvements to Point-to-Point Service. The Commission concludes that the existing methods for evaluating requests for long-term firm point-to-point service are no longer just, reasonable, and not unduly discriminatory. The existing *pro forma* OATT allows the transmission provider to deny a request for long-term point-to-point service if that service is not available in a single hour of the period studied. We find that this approach is not comparable because, when a transmission provider considers a new resource to serve native load, the transmission provider does not eliminate an otherwise economic option because the resource may not be deliverable in a few hours of the year. To remedy this problem, the Commission adopts a "conditional firm" component to long-term point-to-point service that addresses the situation where firm service can be provided for most, but not all, hours of the period requested. We also reform the existing requirements for the provision of redispatch service to ensure that they are of greater use to transmission customers and more consistent with reliability planning and operation of the system.

5.4 Discussion and recommendations

As we have seen in section 5.1, there appears to be no direct obligation on the part of either HQT or the Régie to modify the *Tarifs et conditions* in response to Order 890. If HQP or Hydro-Québec's « wholly owned indirect subsidiary » HQ Energy Services (U.S.) Inc. wishes that HQT modify its tariff documents, they will communicate this to TransÉnergie and/or to the Régie, as would any other third party.

However, as we have seen in section 5.3, Order 890 is the result of a process that began with FERC's recognition that the *pro forma* tariff of Order 888 is inadequate to ensure non-discriminatory transmission access. As such, it is of direct concern to the Régie, which has promulgated a transmission tariff for HQT which relies to a great extent on that *pro forma* tariff.

Thus, regardless of the extent to which HQT sees to the need to modify its tariff in light of Order 890 and regardless of the extent to which HQES or any other third party wishes it to do so, one can see in Order 890 an invitiation to the Régie to carry out its own process to determine to whether or not similar changes are required in its regulation of transmission of electricity in Québec.

As noted in para. 42 of the Order, quoted above, FERC chose to proceed by rulemaking rather than by case-by-case determination « since the most fundamental problems addressed here arise from deficiencies in the *pro forma* OATT itself, not simply the implementation of the *pro forma* OATT by a few transmission providers. » Furthermore, FERC cited the comments of several parties to the effect that their dependance on transmission providers for transmission service, combined with the absence of timely or effective ways to challenge determinations by transmission providers, prevented them from making their concerns known in the ordinary course of business.[43] Fior this reason, simploy referring to the extent or absence of formal complaints filed is not adequate to demonstrate that all is well.

Insofar as the Régie finds that some or all of the flaws in the Order 888 OATT identified by FERC are also present in HQT's *Tarifs et conditions,* it would appropriate for it to enquire further into difficulties or concerns that may be experienced by HQT's transmission unaffiliated clients.

The Régie has already invited these clients to participate in a working group with respect to the short-term rates and discounts, described above in section 4. In concert with its other efforts to increase third-party usage of HQT's transmission system, I recommend that the Régie solicit comments from current and potential users of HQT's system, as well as other interested parties, with respect to the reforms set out in Order 890, whether in the context of a formal rulemaking-type proceeding or by some other means that the Régie deems appropriate.

6 Cost allocation methodology

In D-2006-66, the Régie decided to base the cost allocation for generation-related transmission assets (équipements de transport associés à la production) on both capacity and energy, stating :

> La pratique nord-américaine réfère à la possibilité de répartir les coûts de transport en énergie et en puissance lorsque les coûts des équipements de production sont répartis sur cette base. Selon cette approche, une part des coûts de transport est présumée être encourue <u>pour desservir de façon fiable l'appel de puissance moyen des clients tout au long de l'année, soit la portion énergie</u>, et l'excédent de ces coûts est présumé encouru pour satisfaire l'appel de puissance à la pointe. Les méthodes de ce type sont généralement établies à partir de la méthode du facteur d'utilisation du réseau. (p. 15, emphasis added)

[43] Order 890, paras. 27-38.

It went on to specify that :

> Pour la détermination des composantes puissance et énergie du coût de service du Transporteur, la Régie retient le facteur d'utilisation déterminé à partir de l'énergie totale et de la pointe coïncidente, incluant l'interconnexion Churchill Falls. (p. 16) (emphasis added)

Thus, the Régie stated clearly that the allocation of the cost of certain assets should be based on the total amount of energy transmitted.

However, the capacity/energy breakdown of the cost of service for the test year 2008 presented by HQT shows that, for generation-related transmission assets such as « postes élévateurs » and « lignes de raccordements », in which almost 60% of the costs are to be allocated to energy, only 1.72% of the cost of service is allocated to point-to-point service, and the remainder to Native Load. For assets whose costs are allocated on the basis of capacity alone, this percentage is practically identical — 1.63%.

In contrast, based on HQT's forecasts, total point-to-point energy transfers in 2008 will amount to over 15 TWh,[44] which represents more than 8% of the total energy to be transmitted by HQT in 2008.[45]

In order to understand this apparent discrepancy, it is useful to return once again to the modifications to FERC methodology made by the Régie in D-2002-95, in this case with respect to Direct Assignment Facilities (DAFs, or *Installations d'attribution particulière*).

Direct Assignment Facilities are defined in the FERC's *pro forma* tariff (and in TransÉnergie's reg. 659, which was in force from 1997 until 2002) as :

> Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff.

The costs of Direct Assignment Facilities are borne directly by the transmission customer, and thus are excluded from the transmission provider's ratebase. In the world of the *pro forma* tariff, generation-related transmission assets (GRTAs, or *équipements de transport associés à la production, ÉTAP*) would thus normally have been treated as DAFs.

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[44] Estimated from HQT-11, doc. 2, p. 5, Tableau 1.

[45] HQD data from R-3644-07, HQD-2, doc. 1, p. 5, Tableau 1.

After considerable debate in R-3401-98, however, the Régie decided to eliminate the concept of DAFs from TransÉnergie's *Tarifs et conditions,* and to include all high-voltage lines in HQT's ratebase, regardless of their functional role.

The Régie's decision in D-2006-66 to include an energy component in allocating the costs of GRTAs (ÉTAP) flows to a great extent from this choice. This decision recognizes that GRTAs differ from other components of the transmission system in that their size does not depend on the system peak, but rather on the generator's installed capacity. Similarly, decisions as to the optimal capacity for interconnections depend on estimates of the expected levels of surplus power to be exported, as well as the capacity of the receiving system. Taking energy transfers into account in cost allocation and ultimately in ratemaking is one way to acknowledge the unique role of generator leads and interties (interconnections) in TransÉnergie's system.

In D-2002-95, the Régie chose to accept, « pour la présente décision », HQT's proposal to allocate all costs based on the annual peak. It tooks pains, however, to mention that this decision was not definitive, but was subject to revision following completion of a full cost allocation study, which was to be completed within one year.

> Toutefois, étant donné le degré insuffisant de précision de l'étude produite par le transporteur, <u>la Régie ne peut conclure de façon définitive sur le caractère adéquat ou non de l'approche du transporteur dans une perspective à moyen et à long terme</u>. La Régie juge nécessaire de disposer, pour ce faire, d'une étude d'allocation des coûts effectuée suivant les règles de l'art de la tarification tout comme cela est pratique courante pour établir les tarifs dans le domaine gazier au Québec.
>
> La Régie ordonne au transporteur de déposer, dans un délai maximum d'un an après la parution de la présente décision, une étude d'allocation des coûts incluant les trois étapes susmentionnées et reflétant les préoccupations de la Régie. (D-2002-95, p. 212) (emphasis added)

At the same time, the Régie asked that special attention be paid to generation-related transmission assets and interties:

> La Régie considère que les fonctions, telles que détaillées dans la pièce HQT-10, document 2, constituent une base de départ raisonnable aux fins d'allocation des coûts, eu égard aux caractéristiques du réseau du transporteur. Néanmoins, la preuve au dossier fait ressortir <u>la nécessité d'une attention particulière de certaines installations, tels que les équipements associés aux centrales de production et les interconnexions</u>. (Ibid.) (emphasis added)

This special attention to generation-related equipment and interties is necessary because these facilities appear to be exceptions to the general rule that transmission networks are sized to meet their peak demand.

In the section of D-2006-66 concerning cost allocation, the Régie for the first time specified that the costs of GRTAs should be allocated in part based on total energy.

> La Régie porte une attention particulière à la notion d'équipement de transport associé à la production en raison des caractéristiques propres au réseau, notamment son étendue géographique, le rôle particulier de certaines lignes et la nature essentiellement hydraulique du parc de production. Ainsi, si les centrales n'avaient pas été construites, les équipements de transport associés, dont une très grande partie des lignes THT, n'auraient pas été requis. Le rôle de ces équipements est d'intégrer la production électrique des centrales vers les centres de consommation, ce qui explique que leur flux électrique soit, pour l'essentiel, à sens unique. (D-2006-66, p. 11) (emphasis added)
>
> Selon la Régie, la finalité du réseau est d'assurer le transport de l'électricité, de façon fiable à tous les utilisateurs, et ce durant toutes les heures de l'année. En raison de l'importance des équipements associés à la production dans le réseau du Transporteur et de la nature de la production qu'ils acheminent, la Régie conclut à l'inclusion d'une composante énergie dans la répartition des coûts des équipements de transport associés à la production. L'énergie transitée dessert aussi bien les besoins de pointe que ceux des autres périodes de l'année. Pour déterminer la composante énergie, la Régie privilégie la méthode du facteur d'utilisation qui alloue à l'énergie une part des coûts égale au facteur d'utilisation mesuré en fonction de la pointe du réseau. Cette méthode prend également en compte une composante puissance permettant de refléter les coûts supplémentaires encourus en pointe pour desservir les clients.
>
> Cette approche reflète la mission du Transporteur et les caractéristiques essentielles du réseau de transport. Pour la détermination des composantes puissance et énergie du coût de service du Transporteur, la Régie retient le facteur d'utilisation déterminé à partir de l'énergie totale et de la pointe coïncidente, incluant l'interconnexion Churchill Falls. La Régie retient comme facteur de répartition les pourcentages de 61 % pour la composante énergie et 39 % pour la composante puissance. (Ibid., pp. 15-16) (emphasis added)

Thus, for the first time, the Régie recognized that energy, as opposed to capacity, is an important determinant in transmission cost allocation. Based on the statement quoted above from D-2002-95, there is thus reason to believe that it will eventually also be taken into account in setting rates as well.

With this decision, the Régie rejected the position argued strongly by HQT to the effect that the costs of all functions of the transmission system, including those related to generating stations, should be allocated based on peak capacity alone.[46] It relied instead on an alternate scenario prepared by HQT, at the Régie's request, which allocated GRTAs between capacity and energy based on the capacity factor.[47]

In making this allocation, HQT's alternate scenario in R-3549-04 phase 2 took into account only the energy associated with long-term firm point-to-point reservations. It justified this choice on the basis that only long-term point-to-point reservations can influence system planning.

However, the vast majority of the assets the costs of which are being allocated under this methodology were planned neither for long-term nor for short-term point-to-point service, but for the use of the integrated utility Hydro-Québec. Furthermore, even if they had been built for long-term service, the fact that clients now prefer instead to use short-term service in no way changes the cost causation of these assets, the way those costs were incurred, or the way they should be allocated.

The Régie, in D-2006-66, did not explicitly address this question. However, in describing HQT's position, it used bold type in a way that could be read to suggest its agreement with the Transmission Provider's position, even though it does not explicitly identify this as the position of the Régie:

> Le Transporteur répartit les composantes de son coût de service entre la charge locale et le service de point à point de long terme. **Cette répartition entre les services fermes de long terme est adéquate puisque seuls ces services sont pris en compte aux fins de la planification du réseau. Seuls ces services sont à la source de dépenses significatives d'investissement pour le Transporteur.**

This interpretation is supported by the note to the Régie's Table 1 (page 21), which indicates that point-to-point data are based on long-term service only.

It is, however, difficult to reconcile this approach —allocating costs based only on energy transmitted under long-term point-to-point reservations — with the explicit statement quoted earlier that :

> Pour la détermination des composantes puissance et énergie du coût de service du Transporteur, la Régie retient le facteur d'utilisation déterminé <u>à partir de l'énergie totale</u> et de la pointe coïncidente, incluant l'interconnexion Churchill Falls.

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[46] R-3549-04 phase 2, HQT-3, doc. 1.

[47] R-3549-04 phase 2, HQT-3, doc. 7.

It is also difficult to reconcile with the full explanation from pages 15 and 16 of the decision, quoted above.

In this passage, the Régie concluded that the allocation should be based in part on total energy because the GRTAs would not be needed if the underlying generating stations had not been built, and because the energy transmitted over them is used not only during peak but throughout the year.

Clearly, not all of this energy is delivered via long-term reservations. Much of it is transferred to HQD, either as patrimonial or post-patrimonial energy. As for the rest, as HQT has mentioned many times, short-term reservations account for an ever-greater share of these exports.

Furthermore, in proposing the addition of article 12A.2 to the *Tarifs et conditions* in R-3605-06, HQT made clear that future generating stations may not necessarily rely on firm long-term reservations for point-to-point service either. Thus, HQT explained the difference between option i (based on a firm long-term reservation) and option ii (based on short-term reservations) as follows :

> Dans le cas de l'article 12A.2 ii) par contre, le propriétaire de la centrale s'engage à recourir aux services de transport de point à point à court terme.[48]

Since new generating stations will not necessarily take long-term reservations and since their integration costs should be allocated in part on the basis of *total energy*, the calculation of total energy must include that transmitted under short-term as well as long-term reservations. To do otherwise would systematically underestimate the costs caused by the underlying generating stations.

Indeed, having excluded the energy transmitted under short-term reservations, the cost allocation presented in HQT-12, doc. 2 suggests that the point to point service is excessively profitable. According to Table 8, the costs allocated to the point to point service are only $38.4 million, whereas the expected revenue is $163 million.[49]

If and when the rate structure is eventually reevaluated on the basis of the cost allocation, as called for in D-2002-95, this under-allocation, if allowed to go uncorrected, will inevitably lead to calls to reduce point-to-point rates — and increase charges to Native Load — accordingly. The result will be to impose a a disproportionate share of the fixed costs of GRTAs on Native Load.

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[48] R-3605-06, HQT-13, doc. 10, p. 34.

[49] HQT-13, doc. 1, p. 11, Tableau 4.

In my view, the Régie's explanation, quoted at length above, of why total energy must be included in cost allocation is convincing. To be consistent with this view, the Régie should henceforth require that energy-related allocation be based on total energy transmitted, whether it is done so under a long-term or short-term tariff.

7 Summary of findings and recommendations

7.1 Hourly point-to-point tariffs

The list of point-to-point services offered by TransÉnergie should be modified to distinguish between peak and off-peak hourly periods, with rates sets according to the AEP method. This would be methodologically appropriate and would constitute an effective step to respond to the decline in point-to-point revenues.

The Régie should promptly determine whether or not s. 49, para. 1, subparagraph 11 of the *Act sur the Régie de l'énergie* prevents it from establishing different point-to-point rates, or different discounts, for transactions originating within or outside of Quebec.

In closing, it should be noted once again that short-term rates and discount policy are deeply interrelated. Should the Régie accept our proposal to set peak and off-peak hourly rates according to the standard AEP method, the advantages and disadvantages of discounts will have to be re-evaluated.

7.2 Modalities of the compte d'écart point-to-point revenues

The Régie should reconsider its decision in D-2007-08 to include long-term customers in the disposition of the *compte d'écart*. Given the close similarity between long-term and short-term service recognized by the Régie, I recommend including long-term service in calculating the *compte d'écart,* and excluding it from the distribution.

If the Régie chooses to maintain the retroactive modification of long-term pricing, it should, to be consistent, base that correction on the actual (as opposed to forecast) relation between native load and long-term point-to-point needs. In other words, it should take into account HQD's actual (not forecast) loads. This would have the additional benefit of providing an incentive to HQD to reduce its peak loads in real time. Currently, as HQD's contribution for each year has already been set based on projected loads, there is no such incentive.

7.3 The implications of FERC Order 890 for transmission regulation in Québec

It appears that TransÉnergie does not benefit from a FERC safe-harbour tariff, and thus is under no positive obligation to modify its tariff in response to Order 890.

We are not aware of the nature of any bilateral arrangements it may have with neighbouring ISOs, or the extent to which they may create obligations of this type.

If H.Q. Energy Services (U.S.) Inc. or any other Hydro-Québec affiliate requires tariff modifications to maintain its Market Based Rate authorization, it should formally request such modifications of TransÉnergie and/or of the Régie.

While TransÉnergie appears to be under no direct obligation to modify its tariff in conformity with Order 890, the issues addressed in the rulemaking proceeding that led to this Order — the potential shortcomings of open access transmission tariffs like TransÉnergie's — are potentially of great concern to the Régie.

FERC has found that its existing *pro forma* OATT could not fully remedy undue discrimination because transmission providers retained both the incentive and the ability to discriminate against third parties, particularly in areas where they enjoy significant discretion.

Key areas identified for reform include:

- Lack of transparency
- Transmission planning
- Measuring of ATC
- Pricing of energy imbalances, with exemption from punitive charges for intermittent renewables
- Methods for evaluating requests for long-term firm point-to-point service

The Régie has already invited HQT's current and potential customers to participate in a working group with respect to the short-term rates and discounts, described above in section 4. In concert with its other efforts to increase third-party usage of HQT's transmission system, I recommend that the Régie solicit comments from current and potential users of HQT's system, as well as other interested parties, with respect to the reforms set out in Order 890, whether in the context of a formal rulemaking-type proceeding or by some other means that the Régie deems appropriate.

7.4 Cost allocation methodology

In D-2006-66, the Régie recognized that energy is an essential element in the allocation of the costs of generation-related transmission equipment and interties, because generation-related transmission assets (GRTAs) would not be needed if the underlying generating stations had not been built, and because the energy transmitted over them is used not only during peak but throughout the year. However, it indicated, without explanation, that the measure of the energy component should be limited to energy transmitted under firm long-term point-to-point service.

Clearly, not all of this energy is delivered via long-term reservations. Much of it is transferred to HQD, either as patrimonial or post-patrimonial energy. As for the rest, as HQT has mentioned many times, short-term reservations account for an ever-greater share of these exports.

Furthermore, the vast majority of the assets the costs of which are being allocated under this methodology were planned neither for long-term nor for short-term point-to-point service, but for the use of the integrated utility Hydro-Québec. Even if they had been built for long-term service, the fact that clients now prefer instead to use short-term service in no way changes the cost causation of these assets, the way those costs were incurred, or the way they should be allocated.

Indeed, having excluded the energy transmitted under short-term reservations, it is not surprising that the cost allocation presented in HQT-12, doc. 2 suggests that the point-to-point service demonstrates excessive profitability. According to Table 8, the costs allocated to the point to point service are only $38.4 million, whereas the expected revenue is $163 million.

In my view, the Régie's explanation, quoted at length above, of why total energy must be included in cost allocation is convincing. To be consistent with this view, the Régie should henceforth require that energy-related allocation be based on total energy transmitted, whether it is done so under a long-term or short-term tariff.

APPENDIX A

R-3401-98

HYDRO-QUÉBEC'S REVISED APPLICATION

FOR THE MODIFICATION OF RATES

FOR THE TRANSMISION OF ELECTRIC POWER

TESTIMONY OF

PHILIP RAPHALS,

PETER BRADFORD

AND ELLIS O. DISHER

ON BEHALF OF THE RNCREQ

February 7, 2001

CHAPTER TWO

2. Context

Before entering into the substance of Hydro-Québec's application to modify its transmission tariff (reg. 659), it is important to review the context in which it was introduced. As we shall see in section 2.1, obtaining power marketer authorization (PMA) from the Federal Energy Regulatory Commission (FERC) for Hydro-Québec's American subsidiary H.Q. Energy Services (U.S.) Inc. (HQUS) was the driving force behind the adoption of this tariff. In section 2.2, we will review the criteria which govern the attribution of PMAs by FERC. Finally, in section 2.3, we will discuss the relevance of FERC's policies for the present application.

2.1. Hydro-Québec's adoption of an open access transmission tariff

The energy policy promulgated by the Québec government in the fall of 1996 announced for the first time that Hydro-Québec would adopt a transmission tariff. It did so in the following terms:

> The *Act respecting the Régie de l'énergie* makes a specific provision enabling the Régie to set or modify tariffs and conditions under which electricity is transmitted, upon the request of Hydro-Québec. This provision makes reference to wheeling activities and extends the jurisdiction of the Régie to these activities. Hydro-Québec will take advantage of this provision.
>
> The initiative taken here by the government will make it possible to respect the reciprocity requirement formulated by the Federal Energy Regulatory Commission, in its April 1996 order. At that time the FERC stipulated that before foreign regions could have access at market prices and on an equal footing with competing American companies, they must first offer equivalent access to their own grids. The provisions included in the *Act respecting the Régie de l'énergie* make the setting-up of such a service possible, thus opening the door for Hydro-Québec to deal on the American market as an electricity trader.[1] (emphasis added)

The relationship between the transmission tariff and HQUS' PMA application to the FERC was made even clearer in the order-in-council by which the Government of Québec approved HQ's first open access transmission tariff (reg. 652). The government chose to exempt the order from prior publication,[2] and justified this exemption in the following terms:

> — the new regulatory framework for wholesale electric transmission in the United States will come into force on 1 January 1997;

[1] Government of Québec, *Energy at the Service of Québec: A Sustainable Development Perspective* (1996), p. 57.

[2] Under art. 12 of the *Regulations Act*, prior publication of a draft regulation can be dispensed with when the urgency of the situation so requires.

— potential sales of Hydro-Québec to the United States will be vulnerable to complaints from the competition if the Corporation does not comply with the new regulatory framework by filing with the "Federal Energy Regulatory Commission" an application for authorization to sell electricity at market prices and a bylaw establishing the conditions and rates of wholesale electric transmission service approved by the Government;

— Hydro-Québec will be able to profit by new sales opportunities to the Unites States as soon as it may avail itself of the conditions of the new American regulatory framework;

— it is expedient for the Government to approve as soon as possible Hydro-Québec bylaw number 652 establishing the conditions and rates of wholesale electric transmission service;3 (emphasis added)

Two months later, on February 14, 1997 Hydro-Québec's Board of Directors replaced this tariff with reg. 659, after FERC denied a PMA to Powerex (B.C. Hydro's marketing affiliate), despite that company's adoption of a transmission tariff very similar to reg. 652. In its decision, FERC made it clear that reciprocity would only be granted if the Canadian utility adopted a tariff "consistent with or superior to" the *pro forma* tariff prescribed for all utilities under FERC jurisdiction in Order 888.[4]

The new tariff, reg. 659, was then approved by Cabinet on March 5, 1997; once again, it was exempted from prior publication, for reasons very similar to those quoted above.[5] That same day, HQUS resubmitted its application to FERC. In its application, it stated that:

> Functionally, jurisdictionally and procedurally, the Régie closely resembles the Federal Energy Regulatory Commission.[6]

It stated further that:

> By design, the non-rate terms of Hydro-Québec's Revised Tariff are virtually identical in all substantive respects to the pro forma tariff and include the provisions adopted by the Commission to ensure open access, comparable transmission service to transmission customers.[7]

This statement is supported by a redline version of reg. 659, showing all textual differences between reg. 659 and the pro forma tariff (Exhibit 7).

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[3] Order in Council 1559-96, 11 December 1996, *Gazette officielle du Québec,* December 31, 1996, vol. 129, no. 10, p. 1248.

[4] FERC, British Columbia Power Exchange Corporation, *Order Rejecting Market-Based Rates Without Prejudice*, Docket ER97-556-000, Jan. 1, 1997.

[5] Order in Council 276-97, 5 March 1997, *Gazette officielle du Québec,* March 12, 1997, vol. 128, no. 54, p. 5487.

[6] FERC, *Revised application of H.Q. Energy Services (U.S.) Inc.*, Docket No. ER97-851-000, March 5, 1997, page 2.

[7] *Ibid.,* p. 5.

FERC accepted reg. 659 as adequate "mitigation" of Hydro-Québec's transmission market power on May 9, 1997,[8] and granted the PMA on November 12, 1997.[9]

2.2. Power marketer authorization

As early as 1989, FERC began to recognize that, under certain conditions, it could loosen its regulatory control over prices for wholesale electricity sales without opening the door to monopoly power. Thus, FERC has granted certain companies the right to buy and sell "bulk" electricity without obtaining prior regulatory approval — in other words, to engage in transactions at market-based rates — once it was convinced that they couldn't exercise monopoly power.

At first, this so-called "energy marketer status" was granted only to independent marketers that did not own generation or transmission facilities, had no monopoly service territory and were not affiliated with any such company.[10] In 1993, FERC decided to grant similar status to marketers affiliated with independent power producers (IPPs), as long as they had neither transmission nor a monopoly service territory.[11] More broadly, it would allow such marketers to transact at market-based rates, as long as neither the marketer nor its IPP affiliate had the ability to exercise monopoly control or "market power."

The following year, in its landmark *Heartland* decision,[12] FERC defined the criteria it would apply to the much broader category of marketers affiliated with a utility having a monopoly service territory and/or generation or transmission assets. The criteria established by FERC in *Heartland*, which it still applies today, are that such a marketer must demonstrate that neither it nor its affiliates can exercise market power in either generation or transmission.

Generation market power occurs when a firm owns or controls a significant percentage of generating capacity in the target market or in areas directly interconnected to it.[13] Traditionally, FERC has used "hub-and-spoke" analysis to look at the market share of the affiliated companies for total resources (installed capacity) and uncommitted resources

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[8] FERC, *Order Directing Further Information and Analysis and Deferring Action on Market-Based Rates,* Docket No. ER97-851-000, May 9, 1997.

[9] FERC, *Order Accepting for Filing Proposed Market-Based Rates,* Docket No. ER97-851-000, Nov. 12, 1997. This order was challenged before the U.S. Court of Appeal by the Grand Council of the Crees (of Québec); the appeal was rejected on a matter of standing, without adjudication of the substantive arguments raised (The Grand Council of the Crees (of Quebec) and New England Coalition for Energy Efficiency and the Environment, v. FERC, United States Court of Appeals, D.C. Circuit, No. 98-1280, Jan. 11, 2000).

[10] FERC, *Citizens Power & Light Corp.,* 48 FERC 61,120 (1989).

[11] FERC, *Enron Power Marketing, Inc.*, 65 FERC 61,305 (1993).

[12] FERC, *Heartland Energy Services Inc*., 68 FERC 61,223 (1994).

[13] Energy that is committed under long-term contract to non-affiliated companies is excluded from this analysis.

(surplus capacity) in each "first-tier" market (those markets that are directly interconnected with it). It is increasingly clear, however, that this tool is inadequate — it was recently described by Commissioner William L. Massey as an "anachronism."[14] According to Massey, FERC must redefine its standards for evaluating market power, and should do so in a rulemaking or other generic proceeding.[15] Massey also believes that participation in a Regional Transmission Organization (RTO) should be a condition for market-based rates.[16]

Transmission market power refers to the ability of the marketer or an affiliated company to hinder its competitors from accessing the target market through its control of the transmission system. This could take the form of denying transmission service outright, or of imposing discriminatory rates or conditions.

Since the adoption of Order 888 in 1996, FERC considers that the remedy for transmission market power is for the transmission-owning company affiliated to the marketer to adopt an open access tariff that sets out the terms, conditions and prices for transmission and that guarantees access to all competitors on a non-discriminatory basis. This tariff must be equivalent or superior to the pro forma tariff attached to Order 888. While the adoption of such a tariff is obligatory for all "jurisdictional utilities," there is no such obligation for Canadian utilities or for municipal utilities or co-ops in the U.S. that are not subject to FERC's jurisdiction. However, the reciprocity clause (s. 6) ensures that only non-jurisdictional utilities which have themselves adopted an open access tariff may take advantage of the access rights created by the *pro forma* tariff.

Order 888 was later clarified by Orders 888-A and 888-B. FERC's understanding of "equivalent or superior" is further expressed in the long series cases decided since then in which it has indicated the extent to which it will accept variations from the pro forma tariff proposed by utilities under its jurisdiction, as well as by non-jurisdictional entities seeking to take advantage of Order 888's reciprocity provisions.

2.3. Relevance of **pro forma tariff** *for the Régie*

Given the present context, in which the Régie is called upon to modify a transmission tariff designed by a foreign regulator, there is no Québec or Canadian record to turn to for insight into the meaning or intent of its at times complex provisions. These same provisions have, however, been debated in depth in proceedings before the FERC, and that Commission's orders — which, over time, have articulated, explained, clarified and enforced these very provisions — taken together represent a highly coherent body of jurisprudence elucidating

[14] William L. Massey, "Three Messages from Volatile Electric Markets," EBA Mid-Year 2000 Program, Washington, D.C., Nov. 17, 2000.

[15] Massey, concurring, in FERC, *Order Accepting for Filing Revised Rate Tariffs and Codes of Conduct,* Docket No. ER00-3691-000, 93 FERC 61,193, Nov. 21, 2000.

[16] Ibid. This same view was expressed by several intervenors in the RTO NOPR. In its Order 2000, FERC did not adopt this position, but stated rather that the issue should be addressed on a case-by-case basis.

these provisions and the concepts that underlie them. These orders are essential sources of reference and interpretation for this complex document and, by extension, for Hydro-Québec's reg. 659.

At the same time, it is important to recognize that FERC and the Régie operate under very different legislative mandates. Order 888, and the *pro forma* tariff it contains, were the direct result of the adoption by the U.S. Congress of the Energy Policy Act of 1992, as stipulated in the following passages from the introduction to Order 888:

> A goal of the Energy Policy Act was to promote greater competition in bulk power markets by encouraging new generation entrants, … and by expanding the Commission's authority under sections 211 and 212 of the FPA to approve applications for transmission services. [note omitted][17]
>
> …
>
> As stated by the Commission, in recognition of the Congressional goal in the Energy Policy Act of creating competitive bulk power markets:
>
>> Our goal is to facilitate the development of competitively priced generation supply options, and to ensure that wholesale purchasers of electric energy can reach alternative power suppliers and vice versa. …
>
> As discussed infra, based on the mounting competitive pressures in the industry and rapidly evolving markets, we have concluded that section 211 alone is not enough to eliminate undue discrimination.[18]
>
> In what follows [the body of Order 888], we set out the changes necessary to remedy undue discrimination and to ensure a fair transition to a more competitive regulatory regime.[19] (emphasis added)

No equivalent goals have been set out in the Régie's constitutive legislation or in other binding or non-binding instruments of the Québec government, nor has the Régie adopted such principles on its own.[20]

Finally, we have seen that Hydro-Québec's intention to meet FERC's PMA criteria was the driving force behind its decision to adopt an open access transmission tariff in the first place, and in its design. To the extent that this enters into conflict with other legislative, regulatory

[17] Order 888, pp. 29-30.

[18] *Ibid.*, pp. 34-35. Quote from Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking, 59 FR 35274 (July 11, 1994), FERC Stats. & Regs., Proposed Regulations P32,507 at 32,866 (Stranded Cost NOPR).

[19] Ibid., p. 51.

[20] In R-3405-98, concerning general principles related to transmission tariffs, the RNCREQ asked that the Régie reflect on such questions, and in particular whether or not it should adopt the principles underlying Order 888. In D-98-88, however, the Régie chose not to include these questions in R-3405-98.

and policy goals unique to Québec, the Régie may have to make sigificant tradeoffs. To do so, it will need to understand how the issues addressed in this hearing are understood by the FERC. Only a careful review of FERC rulings will allow the Régie to predict or foresee the effect, if any, of a given modification of reg. 659 on the PMA, and hence on Hydro-Québec's access to the American market.[21]

In this regard, several assertions made by Hydro-Québec in its evidence are somewhat surprising. In response to a request from the Régie to provide, for each proposed modification to reg. 659, the *raison d'être* of the original provision in FERC's pro forma tariff, Hydro-Québec stated that it had not undertaken any study or analysis of the reasoning that guided the FERC in establishing the *pro forma* tariff. It simply states that, in 1997, it had "adapted the pro forma to the Québec context," and that it now wishes to "update it and improve its adaptation to the Quebec context."[22] It reiterated this same response when asked by the Régie to provide the *raison d'être* or purpose of the provisions of reg. 659 that it now wishes to change.[23] Hydro-Québec thus appears not to be concerned whether or not the modifications it proposes, or those proposed by other participants, might affects its subsidiary's PMA.

Similarly, Hydro-Québec has expressed little concern for the implications of FERC's RTO Order (Order 2000), despite the fact that it suggested, as noted above, that RTO membership might eventually be a necessary condition for obtaining a PMA. In its brief to FERC concerning the RTO NOPR, TransÉnergie argued that it "already satisfies the minimum characteristics and functions that the Commission's [sic] has proposed under the RTO NOPR,"[24] an affirmation that was called into question by a number of intervenors.[25]

Asked by the RNCREQ whether Hydro-Québec would once again undertake structural modifications to maintain its access to U.S. markets in the event that FERC found it to be not in conformity with Order 2000, Hydro-Québec merely responded that it "had not examined this hypothetical question."[26] The Motion to Intervene presented by the New Brunswick

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[21] In its 1998 decision on B.C. Hydro's Wholesale Transmission Services, the British Columbia Utilities Commission (BCUC) expressed considerable concern as to the effects its decision might have on Powerex' PMA. BCUC, In the matter of B. C. Hydro and Power Authority, Wholesale Transmission services, Decision, April 23, 1998, pp. 38-41.

[22] HQT-13, doc. 1, R90.1. Unless otherwise noted, any quotations from Hydro-Québec's evidence are our translation.

[23] HQT-13, doc. 1.1, R32.1.

[24] FERC, Docket No. RM99-2-000, Initial Comments of TransÉnergie, Aug. 23, 1999, pp. 1-2.

[25] FERC, Docket No. RM99-2-000, Reply Comments of the Grand Council of the Crees (of Quebec), Greenpeace Canada, Sierra Club of Canada, Mouvement au Courant, the Centre d'analyses de politiques énergétiques and New England Coalition for Energy Efficiency and the Environment, undated; Reply Comments of Project for Sustainable FERC Energy Policy (doc. 19991006-0456). The first required characteristic of an RTO is independence of market participants (FERC, Order 2000, p. 152). As a division of an integrated utility which is an active participant in bulk power markets, it is hard to see on its face how TransÉnergie could meet this requirement.

[26] HQT-13, doc. 14, R5.4.

Power Corp. in this instance stated clearly that Hydro-Québec is involved in discussions with neighbouring utilities for the direct purpose of forming an RTO. In its response, however, Hydro-Québec took the trouble to insist that this issue is unrelated to the present file.

In light of the above, we urge the Régie to take cognizance of FERC's perspective on the various issues raised in this hearing, before arriving at its own conclusions, based on its own legislative, regulatory and policy context. As these contexts are very different from those in the U.S., its conclusions may well differ from those made by FERC.