REVIEW OF PROPOSED HYDROELECTRIC INCENTIVE MECHANISM

1.0 EXECUTIVE SUMMARY

I, Cliff Hamal, have been asked by Ontario Power Generation, Inc. (OPG) to offer an opinion on the reasonableness of its proposed incentive mechanism to promote the efficient dispatch of hydroelectric generation resources. My review is, in part, a response the Ontario Energy Board (Board) request for a more comprehensive analysis of the interaction of the incentive mechanism with surplus baseload generation (SBG), the benefits for ratepayers, and an assessment of potential alternatives.[1]

The existing Hydroelectric Incentive Mechanism (HIM) was approved by the Board in EB2010-0008, and builds on prior incentives. Going forward, OPG proposes a new calculation it calls the enhanced Hydroelectric Incentive Mechanism (eHIM), with the enhancement involving adjusting for the effect of hydroelectric spill associated with SBG. The proposal calls for a new approach to sharing the benefits associated with the eHIM calculation and also expands the coverage of the incentive mechanism to include the hydroelectric generation that is seeking regulated cost-of-service compensation as part of this rate filing.

The eHIM proposal and supporting analysis is presented in evidence Exhibit E1-2-1. This includes a description of the incentive mechanism, the results of modeling its expected benefits and an assessment of alternatives. I have reviewed that material, conducted a review of the underlying analysis and engaged in detailed conversations with OPG analysts into the mechanics of the associated modeling. My review addresses three issues specifically raised in the Board's Decision: the interaction between the mechanism and SBG, the benefits of the incentive mechanism to ratepayers, and an assessment of alternative approaches for providing incentives. In conducting my analysis, I have relied on my extensive electricity industry experience, which is detailed in the attached curriculum vitae.

[1] Decision with Reasons, March 10, 2011, EB-2010-0008, p. 148.

I conclude that the eHIM proposal is both reasonable and beneficial. The proposed change eliminates the potential for overcompensation due to interactions during SBG conditions, provides appropriate benefits to ratepayers after payment of the incentive, and is the best option in light of expected future conditions in the Ontario market.

2.0 THE eHIM PROPOSAL

Under its regulatory framework, OPG is paid a fixed amount for each MWh of hydroelectric generation; this is a strong incentive to maximize generation. This compensation does not give OPG an incentive to shift its hydroelectric output to hours where system energy costs are high and the energy would be of most value to customers. In fact, time-shifting of generation typically involves efficiency loses and therefore reduces OPG's sales volume (MWh) and revenues. Consumers, however, are better served and have reduced costs if generation can be shifted toward hours when it is most needed, generally on-peak periods when prices are highest, even if that results in efficiency losses at the generator and less energy production. Market price in a fully competitive market provides incentives for this shifting. An additional incentive payment in Ontario holds the promise of giving OPG appropriate incentives to dispatch hydro generation in a manner that provides benefits to customers, while working within the hybrid market design and OPG's regulatory framework.

Under the proposal, OPG will receive an annual incentive payment that is based on the eHIM calculation. The eHIM figure is a direct function of the degree to which the weighted average price of hydroelectric deliveries (HOEP times MWh delivered) exceeds the unweighted average price. Thus, the figure reflects the market value associated with shifting electricity production to high-value hours. This was also true of the existing HIM, but under the proposed enhanced calculation, the effects of SBG-induced spill on the incentive payment component are eliminated. The resulting figure is eHIM. The details of this calculation are provided in Exhibit E1-2-1. OPG proposes that its incentive payment be a percentage of the eHIM figure in order to share in the consumer benefits of time-shifting of generation on a 50/50 basis. Also proposed is the elimination of the revenue requirement offset.

The incentive will apply to all regulated hydroelectric generation: the Newly Regulated facilities and those to which HIM had applied in the past. The Newly Regulated hydroelectric facilities are typically dispatchable and have significant ability to store water and shift energy across time. Their operating characteristics contrast with the previously regulated hydroelectric facilities. Among the units historically covered by HIM, the vast majority of storage capacity was associated with the PGS at Beck which can efficiently time-shift hydroelectric generation on a daily basis, but does not provide longer term storage capacity.

The proposal provides incentives to OPG based on HOEP, where that price reflects the need of the system on an hour-by-hour basis. In using a market price to create an incentive, OPG is given a signal that it can directly incorporate into decision making, in real time, to optimize the use of its facilities. Ontario's hybrid market structure involves a variety of different financial structures for the compensation of generation, including contracts and regulation. Regardless of a supplier's regulatory/contract structure, the HOEP provides the best indication of the value of additional generation to the system and the IESO uses HOEP in its dispatch decisions for that reason. For some of the OPA power contracts, it is HOEP that provides the incentive to operate as requested by the IESO, because mismatches between desired and actual production are settled at the HOEP price. HOEP is also central to the pricing of imports and exports. HOEP provides the most appropriate measure of the value of energy in each hour, and therefore it is the best measure of value to use in decision making for the time-shifting of hydroelectric generation across hours and days.

This approach provides a robust incentive under all market conditions. Whether prices are generally high or low, the incentive remains tied to the difference in prices over the hours in which the generation is shifted. The time-shifting might be within a single day, such as is typical for the PGS, or across multiple days for some of the newly-regulated hydroelectric generation. In either case, the incentive is based on the prices in each hour. Thus, if there is a sufficient price-difference to justify shifting from off- to on-peak in a single day, the eHIM mechanism will reward that shifting regardless of prices on other days or whether the overall level of prices was unexpectedly high or low. In addition, the value to customers is associated with the price difference between the periods over which the generation is shifted. Lastly, the eHIM incentive is relative straightforward to calculate. No complications in changing from the HIM to the eHIM approach are expected. The experience with the existing HIM provides added confidence that eHIM can be employed without problems.

3.0 INTERACTION WITH SBG SPILL

The distinguishing change between eHIM and the prior HIM approach is the treatment of SBG-induced spill. Such spill reduces generation during low-priced hours and without the adjustment contained in eHIM would create a positive effect on the incentive mechanism. Since OPG will be made whole for SBG spill through the SBG Variance Account, this increase is unnecessary. Under the proposal, the effect of spill on eHIM is eliminated directly.

It is important to note that OPG still retains the full incentive to shift generation from off-peak to on-peak hours in hours that might otherwise produce SBG-induced spill. That is because of the manner in which the eHIM incentive and the compensation for SBG-induced spill work together. OPG will have a strong incentive to shift generation to on-peak periods to capture the extra compensation from eHIM. It is only if there are residual SBG problems after OPG has done such shifting that it will be asked to spill. When spilling during this situation, OPG is paid the amount it otherwise would have earned through generation for the spilled water, but it will not get an incentive payment. This assures that OPG will give priority to time-shifting generation.

4.0 BENEFITS TO ONTARIO CUSTOMERS

Customer benefits associated with time-shifting of hydroelectric generation come from lower overall payments for electricity. In a fully competitive market, the benefits of reducing on-peak prices would be substantial because customers pay that price, in one form or another, for all on-peak purchases. In Ontario, the situation is much more complicated and benefits are lower because most generators are paid prices that reflect the sum of operating costs and a fixed payment, where that fixed payment is determined through contract terms or through cost-of – service regulation. HOEP plays an important role in providing incentives and in the process of getting payments, but for the most part generators that appropriately follow dispatch instructions are largely indifferent to the level of HOEP.

Customers in Ontario retain some market price exposure, albeit much less than in other markets, that falls primarily in two areas. Customers make payments to cover the cost of fuel, such as natural gas, to generators that face such costs. When hydroelectric generation is shifted into on-peak hours, fossil generation is reduced and the savings in fuel costs gets passed on to consumers. The other source of benefit results from changes in trade in neighboring regions, both the price at which energy is bought and sold and the trading quantities. Customers capture profits from those sales through the market processes; hydroelectric time-shifting will increase those profits by increasing the export price during the off-peak periods when such sales are frequently transacted.

4.1 OPG Calculation of Benefits

OPG has evaluated these effects using a market forecasting model that includes all generation in the province and neighboring regions. Like many production cost models, it determines the lowest-cost means of meeting demand in each hour and allows for trade between regions. The analysis recognizes that in Ontario, most generators are incented to generate on the basis of HOEP, but actual dispatch is determined on a constrained dispatch analysis with congestion payments made as needed. The various OPA contracts and regulated payment mechanisms are also modeled, including the global adjustment. Additionally, the model accounts for the payments made during SBG to resources that curtail generation. I believe it is a reliable modeling tool for this application and is probably the only practical option for such an analysis.

Costs and benefits are estimated by capturing the difference in outcomes in two different scenarios: the base case and the no incentive-hydroelectric case. The base case reflects operations as is presented in the rate case, including hydroelectric spill to manage SBG and dispatch of hydroelectric assets to maximize consumer benefits. In particular, the hydroelectric units are dispatched in a manner that reflects how a competitive firm would operate when fully exposed to the market price. For the conventional hydro units, storage is used to shift production to the higher priced hours, both within the day and across longer periods of time. At the PGS, the model makes dispatch decisions to pump and generate based on an algorithm that considers whether actions taken in a given hour (either pump or generate) will be profitable after all operating costs are incurred. Specifically, the algorithm assumes that PGS pumps when the market price is such that pumping will be profitable if the sales later in the day were at prices that match those of the prior day. It generates using the pumped water if such generation is profitable relative to the pumping cost of the prior evening. This “look-back” approach uses only historical data (i.e., not forecast) that would be available in each hour when pumping and generating decisions would have to be made. In addition, some of the PGS capacity is reserved for the provision of automatic generation control (AGC).

These results are compared to the no incentive-hydro case, which assumes OPG is maximizing its earnings without any hydro incentive. In this scenario PGS is not operated at all, because it reduces the net hydroelectric generation available for sale. The other hydroelectric facilities are operated to maximum production. This is the output level associated with maximum efficiency, at all times. This means that some units are operated 24 hours a day, and others only part of the day but always at maximum efficiency. When only operating for part of the day, the high HOEP hours are selected. The differences between the two scenarios provide the incremental costs and benefits of the eHIM incentive. The results of this analysis are provided in Exhibit E1-2-1 and are summarized in Table 1.

Table 1: Summary Results of OPG's Analysis of eHIM from Exhibit E1		
	2014 M$	2015 M$
Reduction in payments to gas-fired generators	30	27
Increased GRC costs	(16)	(15)
Increase in export revenues	22	24
Total reduction in customer costs	36	36
eHIM calculation, before X factor	51	58
Percentage incentive retained by OPG ('X')	35%	31%
Expected incentive payment to OPG	18	18
Net customer cost reduction (after incentive payment)	18	18

The first item of note in these figures is that the consumer benefits from time-shifting are less than the unadjusted eHIM calculation ($36 million versus $51 million in 2014). Obviously, if OPG were paid the entire eHIM figure, consumers would not benefit from the time shifting. This is the primary driver for OPG's recommendation that it only be paid a fraction of the unadjusted eHIM figure. A major reason for this eHIM being substantially larger than consumer benefits is that the reduction of spill increases the gross revenue charge (GRC) costs. That is a real cost to ratepayers, although, given that the money is paid to the province—effectively taxpayers—this cost has different implications for ratepayers (who are largely taxpayers) than money that might have been paid for fuel or lost through inefficiencies.

Separate from the above calculation of benefits to consumers is the evaluation of costs to OPG. This is provided in the table below. OPG incurs costs for pumping, GRC and non-energy charges, all of which reduce its net benefits from time-shifting hydroelectric generation.

Table 2: OPG costs incurred from time-shifting at PGS		
	2014 M$	2015 M$
Pumping losses	(3)	(3)
PGS GRC costs	(1)	(1)
Pumping non-energy charges	(3)	(3)
Total OPG costs	(7)	(6)
Expected incentive payment to OPG	18	18
Net benefit to OPG from time-shifting hydro generation	11	12

OPG's proposal that its incentive payment be based on a 50/50 sharing of the calculated customer benefit is easily misinterpreted. It does not mean that OPG and customers benefit equally from the time shifting, for two reasons. First, there are substantial costs incurred by OPG in conducting the time-shifting that are not part of the 50/50 sharing calculation—those costs are offset by the incentive payment, leaving OPG with a substantially lower net benefit. Second, the calculation gives zero credit for ratepayer benefits that are likely to accrue from GRC payments to the province. Including consideration of both of those issues allows for a more direct comparison of the benefit-sharing in the proposal. In 2014, customers would achieve $34 million in benefits ($18 million in net cost reductions plus the $16 million in GRC payments) while OPG would benefit by $11 million ($18 million eHIM payment less the incremental costs of $7 million), and as a result customers receive 3 out of every 4 dollars in benefits from the time-shifting of generation.

4.2 Thoughts on OPG's Analysis of Benefits and Structure of Incentive

There are a number of positive attributes of the proposed system that should benefit both customers and OPG. The payment is straightforward and easily calculated, making this an easy process to adopt. The payment is also directly tied to performance in the marketplace—if actual shifting of generation from low-priced to high-priced periods is not accomplished, positive eHIM is not generated and no payments are made.

These issues are important to understanding the results of the modeling. No forecast is perfect. In my view, the greatest value in the modeling is the insight it provides into the relationship between benefits, costs, eHIM and HOEP. With the payment based on a modest portion of the calculated eHIM, customers should be assured of positive net benefits from the program. This is shown through the analysis. The analysis also shows that there are significant costs to OPG from time-shifting. Without any incentive mechanism OPG will lose money from time-shifting, surely a counterproductive incentive.

The modeling assumes that OPG has an incentive to follow market prices, which would be true if OPG were paid the full eHIM amount. But the proposal is based on payments of only about a third of the eHIM figure. Simply put, the proposed structure does not provide as strong an incentive as would be found in an open market, and the incentive is not completely in line with the amount of time-shifting that is assumed to occur. There are two possible implications of this mismatch.

One might assume that OPG's dispatch is based on the market-exposure incentive assumptions, regardless of the sharing detail in the eHIM. As a provincially-owned and regulated entity, it will consider a variety of factors in operating its system, including not only the direct financial incentive, but also the commitment it has made and the need to satisfy the objectives of its shareholder. And while the incentive is reduced by the sharing percentage, it is still sufficient to provide positive benefits after consideration of its incremental costs. Alternatively, one might question that assumption and conclude that OPG's actions more closely match the specific incentive in the shared eHIM approach. If that were true, OPG would do less time-shifting of hydro energy, with the reductions occurring in the hours with the least price benefits. In this instance, while less time-shifting occurs, the benefits to customers are probably very modest in those hours. There does not seem to be much possibility that this result causes any material problem.

This raises the question of whether the sharing percentage is optimal. The approach adopted by OPG, the equal split of the calculated customer benefit, has the advantage of simplicity and apparent fairness. The recommendation appears reasonable as it falls within a range, where the floor would be the lowest level that still provides OPG benefits after considering its incremental costs and the upper end still provides substantial benefits to customers.

5.0 ALTERNATIVE INCENTIVE MECHANISMS

The Board asked that alternative approaches to creating incentives for the dispatch of hydroelectric generation be considered. Exhibit E1 presents and analyzes four options: the proposed eHIM approach, the earlier HIM methodology, an enhanced Hydroelectric Baseload Forecast (eHBF) mechanism and an incentive mechanism (IM) approach. I review each of these alternatives, both as presented by in Exhibit E1 and with modifications, and conclude that the eHIM approach offers significant advantages.

OPG's analysis of the alternatives holds the operations assumptions constant and evaluates how the payments that would be made under the different approaches. Such analyses are important and insightful, but do not give a full understanding of the implications of each approach because they fail to consider the possibility that a different incentive could produce different outcomes. In this case, however, it is relatively straightforward to consider the potential for changes qualitatively, which I do below, and more detailed analysis is unnecessary. In addition, such analysis can be very involved. I do not consider it necessary or cost-effective to conduct such additional analysis in this instance.

5.1 Staying with the HIM alternative

The major difference between the proposed eHIM and the current HIM approaches, as has been discussed, is that under HIM the contribution SBG-spill makes to the HIM value is not subtracted. Thus, HIM calculations are substantially greater. (Absent any SBG spill, and assuming the same sharing factor, the figures would be the same.) Payment of that amount to OPG would exceed the benefits it provides to customers. One alternative might be to apply an even smaller sharing percentage to the HIM figure in order to get the incentive payment to a point that provides net benefits to customers and an incentive to OPG. This would be an inferior option: the outcome would be influenced by the need for spill which falls outside of OPG's control and the incentive to actually time-shift would be diminished because of the lower percentage. The eHIM approach is simply better.

5.2 The IM option

Under the IM (incentive mechanism) option, OPG would be paid a share of what it would be paid if the hydroelectric generation was sold at HOEP. A purely competitive firm would obviously get 100% of the HOEP payment and adjust its output to maximize this revenue. This is a possible alternative from a market perspective, but clearly Ontario has moved away from the purely competitive market approach. Among the problems with this approach is that there are large revenue uncertainties associated with yearly water flow and fossil fuel prices (which drive market prices for electricity). That option is clearly outside of consideration for an incentive mechanism. Under OPG's proposal, the incentive payment would be 5% of hypothetical market revenues, and would come on top of what it is paid in regulated rates. That moves the incentive payment to a range that might be reasonable for the amount of money at risk for an incentive mechanism.

The biggest problem with this approach is that there is no reason to believe that a 5% payment would give the output that is desired. It is simply too weak of an incentive. That competitive approach that is desired corresponds to giving OPG an incentive of 100% of the price difference. This incentive is only one twentieth of that amount, and will rarely offset the increased costs and lost sales volume that will result from efficiency losses from time-shifting. Substantial money will be paid, because payments are made on 5% of all output, but little time-shifting will be incented. In addition, the incentive payment will be heavily influenced by overall water flows and prevailing market prices. These are both independent of OPG's dispatch of the hydro resources, reducing the effectiveness of the payment in providing an incentive.

5.3 The eHBF option

Under the enhanced Hydroelectric Baseload Forecast (eHBF) approach, most of the output would be covered under cost of service ratemaking. Above a certain baseline level, however, generation would be sold at HOEP. As long as marginal sale decisions are made on the basis of HOEP, it provides the competitive-market incentive for time shifting that is desired. Thus, this option could provide the incentives for dispatch that are very similar to that for a competitive firm.

The challenge in implementing eHBF lies in establishing the baseline amounts and then evaluating whether the amount paid would be cost-effective in providing the desired outcome. I think the difficulties in both of these areas are insurmountable.

OPG proposes that the baseline amount be set using a statistical analysis based on data over the past five years. The hourly baseline amount is equal to the volume for that particular hour that corresponds to the 5^{th} percentile of output. The idea is to choose a benchmark value for each hour that will be below actual levels 19 out of 20 times. The "extra" generation above this level is then sold at HOEP, with OPG benefiting from its ability to shift the generation to higher priced hours. The process of setting the hourly baseline amounts is critical. If it is too high, insufficient generation is subject to HOEP to provide an appropriate incentive. Too low, and the mechanism can produce a windfall to OPG. While five years of hourly data involves more than 40,000 data points, this is not a random sample and all hours are not interchangeable. There is still only one data point for each hour. And there are lots of reasons why there could be variations, based on high-stream-flow years, unusual patterns of dispatch due to market conditions, timing of spring run-off and disturbances in the electric system that result in unexpected hydro demands. And in any event, if stream flow is unexpectedly high or low in the year when the incentive is being used, it will not provide the appropriate incentive. Customers and OPG are reasonably protected from the consequences of outlier variations in stream flow under cost-of-service regulation, but that advantage would be lost under this approach. This approach can also result in unexpected levels of payments due to changes in market prices having nothing to do with the dispatch of hydro resources.

In short, this is a messy, complicated alternative that could result in large changes in the amount of money paid to OPG for reasons having nothing to do with hydro dispatch and an having nothing to do with customer benefits. It is an inferior alternative.

6.0 SUMMARY AND CONCLUSION

I conclude that the eHIM proposal offers the best potential to provide OPG with a reasonable incentive to optimize the dispatch of hydro facilities and to provide net benefits to customers after considering the incentive payment. The incentive is robust from the perspective of OPG in that it provides a sufficiently strong signal under a wide range of market conditions. It is likewise robust from customers' perspective in that there will be net benefits after considering the incentive payment under a similarly wide range of market conditions. The flexibility inherent in the incentive mechanism can accommodate the range of market outcomes better than a static command-and-control approach. Despite focused effort, I have been unable to develop a better alternative approach.

Curriculum Vitae

Cliff W. Hamal

Managing Director & Principal

SUMMARY

Cliff Hamal specializes in economic issues in the electric power and related industries. For over 30 years he has been involved in a wide variety of engagements, as an economic consultant since 1989 and in technical roles involving power system operations in prior years. Mr. Hamal brings to each assignment a deep understanding of the industry, its operations, and the dynamics of its markets. He approaches each engagement openly, allowing the unique circumstances of each situation to determine the analyses and methodologies most likely to provide insights into the relevant issues. He particularly enjoys unique challenges that require tailored solutions. His clients have included vertically integrated electric utilities, unregulated electric generation companies, load serving entities, fuel and pipeline companies, equipment suppliers, a debt rating agency, a hedge fund and the US Department of Justice. He has provided testimony in cases before the Federal Energy Regulatory Commission, federal courts, state public utility commissions, arbitrators and the Ontario Energy Board.

TOPICAL SURVEY OF PRIOR ENGAGEMENTS

Market Design

Support electricity market development, including analysis of rules, development of modifications, evaluation of likely participant behavior, and assessment of strategic implications. Analyze capacity markets and provide recommendations for their development and evolution. Review dispatch algorithms to determine how subtle changes could affect market prices and efficiencies. Develop market rules that address the potential exercise of market power during periods of congestion.

Competitive Strategy

Assess investment opportunities in electricity generation market. Evaluate a new merchant transmission project with unique technical challenges. Analyze the potential for repowering a generation facility. Assist in the establishment of a power marketing organization and the development of its business strategy. Model a large generation portfolio and evaluate divestiture options. Evaluate business opportunities and public policy options for equipment suppliers.

Power Purchase Agreements

Negotiate and renegotiate power purchase agreements. Evaluate contract pricing terms in light of changed market circumstances. Review implications of "good faith" terms on specific circumstances related to changed market circumstances. Review whether changes to force majeure provisions could lower energy costs. Analyze the value of a power contract to assess employee compensation claims.

Investment Analysis

Evaluate the value of power generation facilities for a potential buyer. Analyze partnership opportunities related to projects in development. Evaluate strategic alternatives for managing spent nuclear fuel in the U.S. Evaluate price forecasts and revenue projections for project-financed investments to support credit ratings by Standard & Poor's. Evaluate investment opportunities at existing facilities related to repowering, pollution control upgrades, and other modifications.

Environmental Strategy

Analyze implications of cap-and-trade and carbon tax climate change initiatives. Investigate strategic implications of changing environmental regulations. Provide a comprehensive analysis of the effect on the U.S. economy of policies targeting technologies considered favorable for the environment. Evaluate pollution control equipment upgrades and fuel switching options related to meeting emission standards. Consider implications of new environmental regulations on asset values.

Market Power Analysis

Evaluate market power issues in energy, capacity and ancillary services markets. Evaluate the implication of mergers and asset acquisitions on market power before the Federal Energy Regulatory Commission and the US Department of Justice. Prepare market based rate applications using FERC's market screen and Appendix A methodologies. Evaluate claims of antitrust violations under the Clayton Act.

Market Participant Behavior

Evaluate participant behavior in markets, including bidding patterns and generation unit availability. Analyze participant behavior in real-time, day-ahead, and longer-term energy markets. Evaluate claims of inappropriate market behavior by generators. Evaluate the behavior of a financial participant in energy and financial transmission rights (FTR) markets. Evaluate ancillary services markets regarding the implications of different market structures on participant behavior. Analyze the potential for specific trades to influence reported market prices.

Economic Testimony

Testify regarding damages in cases involving breach of contract. Testify on power contracting issues. Opine on market design issues. Testify regarding cost responsibilities for must run generation in a dispute centering on changes in the electricity market structure. Testify regarding electricity price forecasts. Serve as an arbitrator in an insurance claim matter involving the value of lost electricity generation.

PROFESSIONAL HISTORY

Since 2011	Navigant Economics	1996-2010	LECG
	1200 19th Street, NW, Suite 850	1995-1996	The Tesla Group, Inc.
	Washington, DC 20036	1993-1994	JFG Associates, Inc.
	Direct: 202.481.8303	1989-1993	Putnam, Hayes and Bartlett, Inc.
	Main: 202.973.2400	1983-1989	Westinghouse Electric Corporation
	Fax: 202.973.2401	1981-1983	General Electric Corporation
	cliff.hamal@naviganteconomics.com	1980-1981	Trinidad Lines and Marine Transport Line

EDUCATION

MS (with Distinction), Industrial Administration, Carnegie Mellon University, 1989.

BS (with Honors), Marine Engineering and Marine Transportation, U.S. Merchant Marine Academy, 1980.

TESTIMONY

On behalf of the Association of Power Producers of Ontario, before the Ontario Energy Board, October 1, 2012 and February 25-26, 2013, in the rate proceeding of Hydro One Networks, Inc., EB-2012-031. Subject: Evaluation of export tariff rates.

On behalf of Montana Alberta Tie Ltd. (a subsidiary of Enbridge Inc.), before the Alberta Utilities Commission, June 15 and September 18 and 19, 2012, Proceeding 1633. Subject: The Alberta Electric System Operator's rule modification, Section 203.6, concerning transmission rights following the addition of a merchant transmission interconnection.

On behalf of Ontario Power Generation, Inc., before the Ontario Superior Court of Justice, Canada, August 26, 2011, February 9, 10 and 13, 2012, Court File No.: 03-CV-252820CMZ. Subject: Review of Mishkeegogamang's claim for damages from electricity sales.

On behalf of PacifiCorp, before the U.S. District Court for the District of Oregon, February 22, 2011, Docket No. 09-1012-HZ. Subject: Dispute over pricing in a power purchase agreement concerning generation, transmission, ancillary services and power in the form of hydroelectric pondage.

On behalf of H.Q. Energy Services (U.S.) Inc., before the Federal Energy Regulatory Commission (FERC), September 1, 2010, Docket nos. ER010-787-000, EL10-50-000 and EL10-57-000. Subject: Changes in the forward capacity market in New England.

On behalf of the Narragansett Electric Company (National Grid), before the Rhode Island Public Utilities Commission, December 9, 2009 and March 9, 2010, Docket no. 4111, regarding the Town of New Shoreham Project. Subject: Power price review relevant to the Deepwater offshore wind project.

On behalf of Ontario Power Generation, Inc., before an arbiter under the Canadian Arbitration Act, in 2009, regarding a confidential matter.

On behalf of Ontario Power Generation Energy Trading, Inc., before the FERC, June 19, 2009 (filed June 23, 2009), Docket no. ER08-580-002. Subject: Market power evaluation for market based rate application for the Midwest ISO market.

On behalf of COALSALES II, L.L.C., before the U.S. District Court for the Northern District of Florida, Pensacola Division, August 19, 2008, December 11, 2008 and February 16, 2010, Docket no. 3:06 CV 270/MCR/MD, in the matter of Gulf Power Company v. COALSALES II, L.L.C. Subject: Damages analysis associated with a claimed breach of a coal sales agreement.

On behalf of the U.S. Department of Justice, before the U.S. Court of Federal Claims, report dated August 4, 2008, Docket no. 04-0033C, in the matter of Consolidated Edison Company v. The United States of America. Subject: Analysis of sale prices of coal and nuclear generation units.

On behalf of Ontario Power Generation Energy Trading, Inc., before the FERC, June 19, 2008 (filed June 27, 2008), Docket no. ER08-580-001. Subject: Market power evaluation for market based rate application for the New York ISO market.

In a non-public investigation before the FERC, June 3, 2008, in response to a request for information. Subject: Analysis of financial transmission right (FTR) trading activity.

On behalf of the Ameren Energy Marketing Company, before the FERC, June 12, 2007 (filed June 18, 2007), Docket no. EL07-47-000. Subject: Review and comment on the economic issues raised in a complaint by the Illinois Attorney General concerning the September 2006 auction used to procure wholesale electricity supplies in Illinois.

On behalf of the Narragansett Electric Company, before the U.S. District Court for the District of Massachusetts, Central Division, May 18, 2007, and June 11, 2007, Docket no. C.A. No. 05-40076, in the matter of TransCanada Power Marketing, LTD v. Narragansett Electric Company. Subject: Review of pricing issues in a wholesale power contract and pricing issues in electricity power contracting more generally.

On behalf of The Association of Power Producers of Ontario (APPrO), before the Ontario Energy Board, March 9, 2007, Docket no. MR-0031-R00. Subject: Evaluation of a proposed change in the pricing algorithm in the Ontario electricity market, with the change related to how generator ramp rates are considered in setting prices.

On behalf of American Electric Power Service Corporation, before the FERC, January 29, 2007, Docket no. EC07-56-000. Subject: Evaluation of the competitive effects of the acquisition of the Lawrenceburg Electric Generation Station.

On behalf of American Electric Power Service Corporation, before the FERC, January 19, 2007, Docket no. EC07-49-000. Subject: Evaluation of the competitive effects of the acquisition of the Darby Electric Generation Station.

On behalf of the U.S. Department of Justice, before the U.S. Court of Federal Claims, report dated June 29, 2006, testimony on October 12 and 16, 2007, and declaration dated September 17, 2008, Docket no. 00-697-C, in the matter of Wisconsin Electric Power Company v. The United States of America. Subject: Evaluation of decisions made by the utility in managing spent nuclear fuel at the Point Beach Nuclear Power Plant.

On behalf of Reliant Energy Services, Inc., before the U.S. Superior Court of California for the County of San Diego, May 25, 2006, in the matter of Jerry Egger, et al., v. Reliant Energy Services, Inc. et al., Wholesale Electricity Antitrust Cases I and II. JCCP Case Nos. 4204 and 4205. Subject: Analysis of purchases made by Montana-based utilities in California markets.

On behalf of The United Illuminating Company, before the FERC, January 20, 2006 and February 28, 2006, Docket no. EL05-76-001. Subject: Evaluation of issues in a contract dispute involving cost responsibilities for reliability must-run generators.

On behalf of Reliant Energy Services, Inc. and four individuals, before the U.S. District Court for the Northern District of California, San Francisco Division, October 7, 2005, Docket no. CR 04-0125 VRW, in the matter of United States of America v. Reliant Energy Services, Inc. et al. Designated as an expert in case involving claims of price manipulation and a criminal violation of the Commodity Exchange Act. Subject: The operation of the California electricity market, price artificiality, and the behavior of market participants.

On behalf of American Electric Power Service Corporation, et al, before FERC, September 8, 2005, Docket no. EC05-134-000. Subject: Evaluation of the market power implications of the acquisition of Reliant Energy's Ceredo generation station with respect to capacity and ancillary service markets.

On behalf of Niagara Mohawk Power Corporation, et al, before FERC, July 19, 2005, Docket no. ER96-2585, et al. Subject: Market-based ratemaking application for National Grid USA affiliated companies.

On behalf of American Electric Power Service Corporation, et al, before FERC, June 24, 2005, Docket no. EC05-98-000. Subject: Evaluation of market power implications of the acquisition of the PSEG Waterford generation unit with respect to capacity and ancillary services markets.

On behalf of Ontario Energy Trading International Corp., and Ontario Power Generation, Inc., before the FERC, April 11, 2005, Docket no. ER02-1021-000. Subject: Evaluation of the potential for market power in U.S. markets using pivotal supplier and market share screens.

On behalf of the U.S. Department of Justice, before the U.S. Court of Federal Claims, report dated November 22, 2004, testimony on March 28, 2005 and April 1, 2005, Docket no. 98-488C, in the matter of

Sacramento Municipal Utility District v. The United States of America. Subject: Review of the damages claim made by SMUD associated with alleged breach of contract for the disposal of spent nuclear fuel.

On behalf of National Grid USA, before FERC, November 4, 2004 (revised November 19, 2004), January 10, 2005, January 28, 2005, March 14, 2005, and March 17, 2005, Docket no. ER03-563-030. Subject: Review of the locational capacity market proposal filed by ISO New England with consideration given to market design, participant behavior, the mechanics of implementing the market, and the cost of new generation capacity.

On behalf of Reliant Energy Services, Inc. and four individuals, before the U.S. District Court for the Northern District of California, San Francisco Division, December 10, 2004, Docket no. CR 04-0125 VRW, in the matter of United States of America v. Reliant Energy Services, Inc. et al. Subject: Review of a report concerning the market effects of certain bidding actions by Reliant on California electricity markets in the summer of 2000.

On behalf of New England Power Co. before FERC, December 24, 2003, March 9, 2004, and April 15, 2004, Docket no. EL03-37-000. Subject: Evaluation of the electricity price forecast used for setting a contract termination charge, as well as the determination of variable costs and generation asset sale prices.

On behalf of Koch Power, Inc., before the Harris County, Texas District Court, Cause no. 2001-48858, in the Matter of Tim Beverick v. Koch Power, Inc., provided testimony summary on August 25, 2003. Subject: Evaluation of the potential for savings under a renegotiated power purchase agreement and the contributions of certain individuals to the renegotiation process.

On behalf of Reliant Energy Services, Inc. before the FERC, April 16, 2003, Docket no. EL03-59-000. Subject: Evaluation of the implications of certain trades of forward energy contracts on the overall electricity market.

On behalf of Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc. before the FERC, March 3, 2003, with rebuttal March 20, 2003, Docket nos. EL00-95-069 and EL00-98-058. Subject: Investigation into alleged manipulative practices by market participants in the California electricity markets in the 2000-2001 timeframe.

On behalf of Ontario Energy Trading International Corp., and Ontario Power Generation, Inc. subsidiary, before the FERC, February 14, 2002, Docket no. ER02-1021-000. Subject: Evaluation of the potential for market power in U.S. markets.

On behalf of The New Power Company before the FERC, July 13, 2001 (filed July 17, 2001), Docket no. EL01-105-000. Subject: Evaluation of the capacity credit market in PJM, primarily focusing on market power issues.

On behalf of National Grid USA before the FERC, January 16, 2001, Docket no. EL00-62-005 and EL00-62-013. Subject: Analysis of the incentives for new generation facilities in New England, and in particular the role of the $8.75/kw-month installed capacity deficiency charge.

On behalf of Oklahoma Gas & Electric before the Arkansas Public Service Commission, November 30, 2000, Docket no. 00-326-U. Subject: Analysis of OG&E's potential market power in a restructured, retail open-access environment.

On behalf of National Grid USA and TransCanada OSP Holdings, LTD before the FERC, August 7, 2000, Docket no. EC00-122. Subject: Analysis of the competitive effects of the proposed acquisition of interests in the Ocean State Power generation facility by TransCanada.

On behalf of Central Illinois Light Company and the AES Corporation before the FERC, February 19, 1999, Docket no. EC99-40. Subject: Analysis of competitive effects of the proposed acquisition of Central Illinois Light Company by the AES Corporation.

On behalf of Public Service Electric & Gas Co., before the United States District Court for the Eastern District of Pennsylvania, Docket no. 96-CV1705, in the Matter of Delmarva Power & Light Company and PECO Energy Company v. Public Service Enterprise Group, Inc. and Public Service Electric and Gas Co., March 28, 1997. Subject: Replacement power costs associated with the multi-year forced outage of the Salem Nuclear Station.

SPEECHES & PAPERS

"Solving the Electricity Capacity Market Puzzle: The BiCap Approach," the seminal paper presenting a new market design and incorporated into a website dedicated to capacity market developments, www.BiCapApproach.com, initiated July 4, 2013.

“Realities in the Pricing of Power in Ontario,” in the session, “Realistic options for getting to truer and more effective price signals,” as part of APPrO 2012, Toronto, Canada, November 7, 2012.

“Opportunities in Spent Nuclear Fuel Consolidation,” as part of a workshop sponsored by the United States Nuclear Infrastructure Council, Baltimore, MD, May 31, 2012.

“How can an economist help with complicated technical and political issues?” in the session, “Spent Nuclear Fuel Storage and Repository Options,” for the Institute of Nuclear Materials Management Spent Fuel Workshop XXVII, Arlington, VA, February 2, 2012.

“Five Thoughts on Evolutionary Change,” in the session, “Market Evolution in the Context of the Electricity Market Forum Road Map and the Post-Election Environment,” APPrO 2011, Toronto, Canada, November 16, 2011.

"Spent Nuclear Fuel Management: How centralized interim storage can expand options and reduce costs," with Julie M. Carey and Christopher L. Ring. A study conducted for the Blue Ribbon Commission on America's Nuclear Future, May 16, 2011.

"Nine Trends to Watch in the Renewable Transformation," with Julie M. Carey. *Dialogue*, United States Association for Energy Economics, Volume 18, Number 3 - 2010.

“Capacity Market Design Fundamentals.” Workshop for EUCI’s conference, “Capacity Resources: Issues and Market Dynamics,” Baltimore, MD, October 27, 2010.

“The Impact of Transmission Expansion and New Renewable Generation on the Evolution of FTR Markets.” Panel moderated for EUCI’s conference, “Financial Transmission Rights: Trends and Trajectory,” Arlington, VA, July 19, 2010.

“Managing FTR Credit Risk.” Panel moderated for EUCI’s conference, “Financial Transmission Rights: Where Are We Now?” Washington, DC, July 28, 2009.

“Credit Coverage Requirements for FTR and Virtual Bidding.” Session moderated for EUCI’s conference, “Unsecured Credit: Is it the right policy for RTOs/ISOs?” Alexandria, Virginia, April 29, 2009.

"Force Majeure Risk and Ontario Power Authority's Power Contracts." Whitepaper with Julie M. Carey, on behalf of the Ontario Power Authority, March 31, 2008.

"Financial Accommodation for Force Majeure Events." Whitepaper with Julie M. Carey, on behalf of Ontario Power Authority, January 21, 2008.

"Market Design Choices for Ancillary Services Products," with Cleve Tyler. Presented at the EUCI Ancillary Services Conference, Minneapolis, Minnesota, September 12, 2007.

"Cost-Benefit Analysis In the Evaluation of Market Rule Changes: Comments on MR-00332-R00." Whitepaper on behalf of Ontario Power Generation, Inc., July 12, 2007.

"Adopting a Ramp Charge to Improve Performance of the Ontario Market." Whitepaper with Arun Sharma, on behalf of The Association of Power Producers of Ontario (APPrO), June 21, 2006.

"Shifting Regulatory Oversight of Utility Mergers," with Cleve Tyler, *Innovating for Transformation*, The Energy and Utilities Project, Volume 6, 2006, page 37.

"Allocation of Emission Allowances for the Regional Greenhouse Gas Initiative." Whitepaper regarding an initiative under consideration in mid-Atlantic and Northeastern regions of the United States, written with Alan Madian, September 20, 2005.

"Toward a Capacity Demand Curve Market," with Julie Murphy, *Innovation for the Future*, The Energy and Utilities Project, Volume 5, 2005, page 46.

"LICAP Key Issues." Presented to Commissioners and staff of the Massachusetts Department of Telecommunications and Energy, Boston, Massachusetts, March 28, 2005.
"Market Power Screens." Presented at the Electric Power Supply Association (EPSA) Annual Fall Membership Meeting, Washington, DC, November 10, 2004.

"Ancillary Service Pricing Dynamics." Presented at the EUCI Ancillary Service Conference, Westminster, Colorado, March 13, 2003.

"California's Electricity Markets: Structure, Crisis, and Needed Reforms." Contributor, January 16, 2003.

"Capacity Payment Schedules: A Workable Approach for Resource Adequacy." Presented to the Energy Bar Association, Washington, D.C., December 12, 2002.

"Power Market Panel." Speaker in the Standard & Poor's 2002 Project, Power & Energy Credit Conference, New York, New York, November 13, 2002.

"Market-Based Pricing of Ancillary Services: Market Design Choices, Consequences and Performance." Presented at the EUCI Ancillary Services Conference, Atlanta, Georgia, September 27, 2002.

"Ancillary Service Market Performance During the Summer of 2002." Presented at the EUCI Ancillary Services Conference, Atlanta, Georgia, September 26, 2002.

"Revenue and Risk from the Lender's Perspective." Presented at the Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.

"Preparing for Antitrust Scrutiny." Panel discussion at the Utility Mergers & Acquisitions Conference, Washington, D.C., July 15, 1998.

"Perspectives of Investors and Developers." Presented at the American Education Institute Conference on Power Contracts in affiliation with the United States Energy Association to the Romanian Electric Authority, Washington, D.C., March 19, 1997.

"Risk and Risk Management in Electricity Markets." Presented at the Electric Load Aggregation Conference, Washington, D.C., November 18, 1996.

"Developing Firm Plans During Uncertain Times: Anticipating Change." Presented during a session titled "Integrated Resource Planning and Demand Side Management After Federal Endorsement," to the Institute of Public Utilities, Williamsburg, Virginia, December 15, 1992.

Numerous speeches and training programs regarding nuclear power plant operations, accident analysis, nuclear engineering and related subjects were given to operators and technical engineering personnel from power plants around the world, 1984-1986.

AFFILIATIONS AND PROFESSIONAL QUALIFICATIONS

Member, International Association for Energy Economics.

Member, Non-Attorney Professional, Energy Bar Association.

Mr. Hamal has held U.S. Nuclear Regulatory Commission certification as Senior Reactor Operator; U.S. Department of Energy qualifications as Nuclear Plant Engineer and Nuclear Engineer Officer of the Watch; and U.S. Coast Guard licenses as Third Assistant Engineer and Third Mate.

August 2013