BEFORE THE

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF:

BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan

Evidence Filed By Robert M. Fagan

Synapse Energy Economics

22 Pearl Street

Cambridge, MA 01730

On Behalf Of:

Sierra Club (BC Chapter), BC Sustainable Energy Association, And Peace Valley Environment Association

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Attachments

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Robert M. Fagan. I am a Senior Associate at Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, Massachusetts, 02139.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I am an energy economics analyst and mechanical engineer with 20 years of experience in the energy industry. My work has focused primarily on electric power industry issues, especially economic and technical analysis of competitive electricity markets development, electric power transmission pricing structures, and assessment and implementation of demand-side resource alternatives. I hold an M.A. from Boston University in Energy and Environmental Studies and a B.S. from Clarkson University in Mechanical Engineering. Details of my experience are provided in my resume as Attachment 1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Sierra Club of Canada (British Columbia Chapter), British Columbia Sustainable Energy Association, and Peace Valley Environment Association (SCCBC, *et al*.).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to examine three related issues pertaining to BC Hydro's 2006 Integrated Electricity Plan (IEP) and the 2006 Long Term Acquisition Plan (LTAP), and especially two F2006 Call elements. These are: 1) the $3/MWh "firming" premium used to evaluate tenders that chose to deliver hourly firm rather than the baseline monthly firm energy resource; 2) the nature of the shortfall liquidated damages (LD) clause in the Electricity Purchase Agreements (EPA); and 3) the operational costs of wind integration as examined on other systems and for consideration in British Columbia.

II. SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The $3/MWh hourly firming premium is an inappropriate adjustment to tendered bid prices at the evaluation stage. BC Hydro's large hydro storage system allows for intra-month buffering such that no incremental opportunity costs are seen from delivery of firm energy scheduled monthly from wind turbine generation (WTG), rather than scheduled hourly, for the same amount of energy. Including this price adjustment at the evaluation stage sends an incorrect price signal, and could result in a sub-optimal selection of tenders. The firming premium should be eliminated from future energy Calls.

The shortfall liquidated damages provision has two important effects: 1) it uneconomically skews the actual purchased costs of wind energy upward, as the presence of the LD clause likely leads WTG Call providers to incorporate this artificial risk into their pricing; and 2) it could lead to BC Hydro rejecting some cost-effective WTG-based projects. The LD clause represents an artificial risk because BC Hydro is not necessarily at risk to purchase more (or sell less) energy externally just because a given WTG generator does not meet 90% of its firm energy amount for a given month. The LD clause should be reconsidered for future energy Calls, and could be restructured to cover a multiple month period, a seasonal or even an annual period, rather than a single month period; or the bandwidth could be increased beyond 10%.

System-wide costs to integrate wind turbine generation are highly power-system-specific, and they cannot be easily imputed for BC based on existing studies. BC Hydro should conduct further, detailed technical studies to evaluate the effect of wind turbine generation operation on its system in both the near term and over the longer term, respecting and anticipating the evolution of wind turbine generation, transmission system and control technologies. Costs for WTG integration in the BC Hydro system are likely to be at or close to zero, especially for the initial period when overall wind penetration in BC as a percentage of installed capacity is low. The reasons relate primarily to the significant storage and exceptional load following capability of the large hydropower resources on the system.

III. HOURLY FIRM ENERGY PRICE ADJUSTMENT

Q. WHAT DO YOU ADDRESS IN THIS SECTION?

A. I examine the $3/MWh “firming” premium applied to certain F2006 Call energy suppliers’ levelized energy bid prices if they chose to provide an hourly firm energy schedule, instead of a monthly firm energy schedule. The premium was applied as a tendered bid price adjustment in the evaluation phase of the F2006

Call, and will not be considered as an actual energy payment adjustment when F2006 Call resources commence operation.

Q. WHAT IS THE CONCEPTUAL BASIS FOR THE HOURLY FIRM ENERGY PRICE ADJUSTMENT?

A. The conceptual basis is the notion that accurately accounted-for and delivered hourly firm energy has explicit additional value compared to that same firm energy accounted for and delivered on a monthly basis to the BC Hydro system. As noted by BC Hydro, "The hourly firm option is intended to incent bidders to provide a higher-value "capacity rich" product, if available, by providing a $3/MWh evaluation credit adjuster for such projects."[1]

Q. WHAT IS THE QUANTITATIVE BASIS FOR THE HOURLY FIRM ENERGY PRICE ADJUSTMENT OF $3 PER MWH?

A. The basis for the $3/MWh premium is a proxy intra-day system capacity cost, estimated as the levelized cost of Revelstoke unit 5. The choice of this proxy is supported by the following excerpt from BC Hydro's 2005 REAP Supplemental F2006 Call Evidence of July 8, 2005, from the direct testimony of Mary Hemmingsen[2]:

> "The basis for the additional value provided by a project that provides firm energy on an hourly resolution is the levelized cost of Revelstoke Unit #5, inclusive of forgone system benefits to BC Hydro, a proxy for BC Hydro's cost of incremental intra-day system capacity." (Page 7, lines 31-34)

[1] 2005 REAP, Exhibit B-11, Direct Testimony of Mary Hemmingsen, p.7, which is cited and discussed at 2006 IEP Exhibit B-10, BC Hydro Response to BCUC IR 2.379.1, attaching 2005 REAP BC Hydro Response to BCUC IR 3.104.1.

[2] *Id*.

Further, Exhibit B[3] of Ms. Hemmingsen's testimony lists "Tender Evaluation Criteria and Methodology – Key Elements", dated July 8, 2005. The following is from page 10 of that Exhibit:

> "Key Element:
> This adjustment applies only to Large Projects. A bidder may elect the hourly firm option (as opposed to monthly firm), in which case an adjustment of $3/MWh will be applied to recognize the benefit to BC Hydro of that election."
>
> Rationale:
> The hourly firm credit provides a evaluation benefit to bidders that can deliver a firmer energy product (i.e. hourly, rather than monthly). The adjustment amount is based on the levelized cost of Revelstoke Unit #5, inclusive of foregone system benefits to BC Hydro.
>
> Comparison with Selected Jurisdictions:
> Among the selected jurisdictions, no specific adjustments were provided for in the evaluation methodology for hourly firm delivery."

Q. DID ANY OF THE OTHER JURISDICTIONS EXAMINED BY BC HYDRO PROVIDE A SIMILAR HOURLY FIRMING PREMIUM?

A. No. As noted in the Tender Evaluation Criteria and Methodology table in Appendix B of Ms. Hemmingsen's testimony, no specific adjustments were provided for in other jurisdictions' methodologies for hourly firm delivery relative to monthly firm delivery of the same energy.[4]

Q. DID BC HYDRO PREPARE DETAILED CALCULATIONS OF THE $3/MWH PREMIUM?

A. Yes. Attachment 2 to this testimony contains a BCUC information request and response (BCUC IR 2.379.1 Attachment 1) originally provided as part of the 2005 REAP proceeding. It illustrates how the $3/MWh value was derived.

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[3] 2005 REAP, Exhibit B-11, Testimony of Mary Hemmingsen, Exhibit B, pdf p.47, *et seq*.
[4] *Op Cit*., page 10.

Q. DOES THE $3/MWH FIRMING PREMIUM REPRESENT AN APPROPRIATE EVALUATION ADJUSTMENT VALUE FOR TENDERS THAT CAN PROVIDE HOURLY FIRM ENERGY?

A. No. There is one primary and one secondary reason the $3/MWh firming premium represents an arbitrary assignment of value to resources that can provide hourly firm energy, to the detriment (at the evaluation stage) of resources that cannot. These reasons are related to i) the type of system operated by BC Hydro, specifically the significant water storage capabilities that give BC Hydro significant intra-month flexibility in dispatching its resources; and ii) the fact that the existing BC Hydro system exists and is operated within a cost-based regulatory system and not a market system for retail consumers.

Q. HOW DOES THE WATER STORAGE CAPABILITY OF THE BC HYDRO SYSTEM AFFECT THE VALUE OF THE FIRMING PREMIUM?

A. The hourly firming value is inaccurately expressed as BC Hydro's cost of intra-day capacity, as stated by Ms. Hemmingsen. It is more accurately expressed as BC Hydro's energy-based opportunity cost of *not* having access to a predictable hourly delivery schedule for a F2006 Call resource, one that does not provide hourly firm energy, such as certain wind turbine generators. That opportunity cost can be expressed as the extent to which BC Hydro is not able to earn as much revenue from surplus energy sales (or has to spend more to purchase energy if it is in shortage) within a given month because of the presence of F2006 Call resources that are not scheduled hourly, in comparison to F2006 Call resources that would provide an equal amount of monthly firm energy but follow hourly delivery schedules.

In other words, the premium assumes that on average there is an effective $3/MWh opportunity cost *within* a given month tied to all monthly firm energy received from Call resources that cannot choose the firm hourly delivery; and no such opportunity cost for Call resources that can commit to hourly delivery schedules within the same month.

For resources that cannot make an hourly delivery commitment – such as WTG resources – such an opportunity cost might be present on some power systems, but not on BC Hydro's system. Its storage and ramping capacity provides sufficient intra-month buffering capability to handle both hourly load variation and varying output from wind resources without disrupting the overall pattern of extra-Provincial sales or purchases within a given month.

Q. WHAT EVIDENCE DO YOU HAVE THAT BC HYDRO'S SYSTEM CONTAINS SUCH SUFFICIENT INTRA-MONTH BUFFERING CAPABILITY?

First, BC Hydro describes its reservoir system as able to store water for several years. While this does not necessary imply water will be stored for that long, it does imply that on significantly shorter time scales (than year-to-year) a buffering capability exists; indeed, that buffering capability is a fundamental characteristic of storage hydro systems. Operation is not likely to be significantly effected *within a given month* if the same amount of F2006 Call firm energy is delivered to the system on an hourly schedule, or is delivered on a monthly schedule, especially when considering a monthly schedule that reflects the pattern of wind speed distribution over a month.

Second, BC Hydro's system is capable of significant hour-to-hour operational changes. Its ramping capability is very high. Attachment 3 of this testimony summarizes the hour-to-hour changes in BC Hydro load, BC Hydro exports and imports over the two-year period from 2004 through 2005, and also (by simple derivation) BC Hydro's generation portfolio ramping capability. This exhibit illustrates – not unexpectedly given the hydro foundation of the portfolio – a capability to change generation output by as much as thousands of MW per hour, and thus reliably follow a wide range of gross load variation, or net load variation that incorporates the effect of wind generation variability.

Q. WHAT IS THE ACTUAL OR PROJECTED INTRA-MONTH OPPORTUNITY COST ASSOCIATED WITH F2006 CALL MONTHLY FIRM ENERGY FROM CALL RESOURCES THAT CAN'T PROMISE HOURLY DELIVERY, RELATIVE TO CALL RESOURCES THAT DO CHOOSE THE HOURLY SCHEDULING OPTION?

A. There is no computation or presentation of information by BC Hydro that describes the intra-month relative opportunity cost. I assert that that value is either zero or much closer to zero than it is to $3/MWh because the storage capabilities of the BC Hydro system are large enough to allow water storage for several years[5]. Furthermore, under realistic scenarios of monthly firm energy

[5] See, for example, Section 7.7.2, "Optimizing Reservoir Operation" from BC Hydro's 2007/2008 Revenue Requirements Application (RRA Exhibit B-5-1, p.7-35), which states "For hydroelectric projects with some

delivery by a wind resource, the quantity is likely to be distributed over the course of the month, and not lumped into, say, a few days. This implies a pattern of overall energy delivery to BC Hydro that would likely lead to effectively similar demands on the hydro reservoir system compared to a dispatchable, or hourly schedulable, resource. Operationally, the significant difference between the resources is the hourly or daily predictability; however, as noted earlier, the relative opportunity cost is not proportional to hourly variations in delivery because of the buffering capability of the hydro resource.

Thus, provision of an equal quantity of monthly firm energy delivered either on an hourly basis or more flexibly over the course of a month (e.g., such as would be seen with wind turbine generation) would result in BC Hydro likely having the same ability to meet surplus capacity sales obligations or to purchase off-system energy in similar patterns. On any given day or week within the month the operation of the reservoir system may be slightly different depending on the exact pattern of delivery of F2006 Call resources, but the overall market-related opportunity costs would be the same because the overall difference in operation – within the month - would be negligible.

Q. HOW DOES THE COST-BASED REGULATORY ENVIRONMENT AFFECT THE VALUE OF THE FIRMING PREMIUM?

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discretionary storage, water can be stored for later use. Therefore, a decision to release water (generate electricity) incurs an opportunity cost equal to the market value that the water would provide if it was used at a later time. BC Hydro has several unique reservoirs that are very large and can store water for several years. Therefore, the decision of when to use the water in the reservoir must consider this long time frame (i.e., anytime between the next hour and the next 3-4 years)".

A. Under a cost-based regulatory regime, the intra-day value of capacity is dependent on the availability and cost of the resources of the entire system. The marginal value of a single new capacity resource (such as Revelstoke 5) is not representative of actual system-wide intra-day capacity opportunity costs.

Specifically in the BC Hydro system, F2006 Call resource providers are not operating within a market system where a particular marginal resource value is necessarily a relevant benchmark for opportunity costs, such as is planned in some competitive RTO structures in the Eastern US.[6] The Revelstoke 5 computation is useful to inform estimates of levelized costs for the next capacity unit planned for the system, but the computational result is not applicable as an actual opportunity cost metric associated with energy provision. In BC, energy is provided and charged for in a regulatory environment that looks at system-wide costs.

Similarly, the "value-based approach" noted in BCUC IR 2.379.1 Attachment 1 (included here as Attachment 2 to this testimony) is also tied only to Revelstoke 5. That approach reviews the value of the increased energy available from installation of Revelstoke 5. This also does not represent an appropriate system-wide valuation of opportunity costs.

Q. WHAT DO YOU RECOMMEND IN REGARDS TO THE $3/MWH FIRMING PREMIUM?

[6] For example, pending capacity markets in the PJM and New England regions tie prices to the cost of a new peaking unit.

A. I recommend the premium be eliminated from the evaluation process for any future energy Calls, based on the evidence provided above.

IV. DELIVERY SHORTFALL LIQUIDATED DAMAGES

Q. WHAT DO YOU ADDRESS IN THIS SECTION?

A. In this section I address the "Delivery Shortfalls" section of the liquidated damages (LD) provisions included as Section 12.2 of the Large Project Electricity Purchase Agreement (EPA). I consider its impact on wind turbine generators' provision and pricing of Call energy.

Q. PLEASE SUMMARIZE THE PROVISIONS OF SECTION 12.2 OF THE LARGE PROJECT ELECTRICTY PURCHASE AGREEMENT.

A. Section 12.2 of the Large Project EPA describes the liquidated damages that will apply to F2006 Call suppliers who deliver less than 90% of the monthly firm energy for that month (i.e., "Delivery Shortfalls" liquidated damages).

F2006 Call suppliers elect a certain quantity of energy to be supplied as "firm" energy within the month. All other energy supplied will be treated as "nonfirm" energy, either Tier 1 or Tier 2, and paid a rate lower than the baseline rate. I understand the Tier 1 non-firm energy rate to be $8/MWh lower than the contracted firm energy rate and the Tier 2 non-firm energy rate to be equal to the lesser of the Tier 1 non-firm price or an amount equal to 70% of the average of the daily non-firm Mid-C off-peak index prices in the applicable month.[7]

[7] This is reflected in the Standard Form Electricity Purchase Agreement for Large Projects, Appendix 3, Energy Price. This is also based on the non-firm Tier 1 power pricing provisions of the 2005 REAP Negotiated Settlement Agreement, included as Appendix 1 to the BCUC's Order No. G-103-05, all of

Liquidated damages are equal to the "LD Factor" multiplied by the difference between a) 90% of the monthly firm energy amount and b) the actual delivered eligible energy. Thus, liquidated damages will only apply if there is a shortfall that is more than 10% of the contracted monthly firm energy.

The LD Factor is tied directly to a "Mid-C Index" price, which is comprised of the weighted hourly average of two daily Mid-C price benchmarks for each of on-peak and off-peak hours. The Mid-C price is used as a benchmark pricing metric for bilateral energy transactions in the Pacific Northwest of the US and the broader Western US, BC and Alberta region. The LD Factor is also tied to the Call provider's bid price, adjusted for transmission losses and escalated based on the CPI. In essence, the LD Factor attempts to capture, on average over a month, the differential value of firm energy not supplied by the Call supplier at the Call price, and instead supplied by BC Hydro at the Mid-C price.

Also, the LD provision can only be a positive quantity. If a Call provider is short firm energy in a month when Mid-C prices are lower (on average) than the Call price, no credit is given to the Call provider recognizing the opportunity gained by BC Hydro in not having to purchase at the higher Call price in that month for the shortage amount.

Lastly, excess energy above the monthly firm amount does not get credited at a rate tied to Mid-C prices. While a WTG supplier bears the LD risk, there are no provisions in the EPA to allow an "upside" to payments reflecting the value of excess (or non-firm) energy during times when the Mid-C price is high

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which was included as Appendix A to BC Hydro's "Report on the F2006 Call for Tender Process Conducted by BC Hydro", August 31, 2006.

and/or when surplus wind energy is available. That energy is paid at Tier 1 or Tier 2 non-firm prices, significantly lower than the firm energy price. Thus, BC Hydro has exposed WTG suppliers to a market risk associated with Mid-C pricing, but has not provided for any market-based reward mechanism.

Q. HOW WOULD THE SHORTFALL LIQUIDATED DAMAGES PROVISION AFFECT A HYPOTHETICAL WIND TURBINE GENERATION PROVIDER OF CALL ENERGY?

A. A WTG may not be able to accurately predict (within 10%) the amount of energy that can be supplied in any given month, although a multi-month, seasonal or annual prediction is highly likely to be more accurate, perhaps within the 10% band. Unlike other potential providers such as those using fossil fuels, the inability to accurately predict (for a given month, within 10%) WTG output is not due to the fault of the supplier, but rather is based on the inherent uncertainty and unpredictability of wind speed distribution over a given month. All energy generated above the monthly firm amount is still sold to BC Hydro, but at a discount of at least $8/MWh, based on the Tier 1/ Tier 2 non-firm pricing provisions.

Thus, the ultimate effect of the presence of the LD clause is that a WTG provider would likely tender an overall higher energy price for WTG-based Call energy because they either 1) need to incorporate the potential punitive impact of the LD clause in order to account for LD payouts to BC Hydro, or 2) avoid LDs by more conservatively tendering a lower amount of firm energy (from the same size and cost resource) and thus accept a relatively steep $8/MWh (or more) discount on more of the energy provided by the wind turbine generation.

Q. WHAT EFFECT DOES THE PUNITIVE IMPACT OF THE LD CLAUSE HAVE ON WTG PROVIDERS AND WTG SUPPLY PRICES IN GENERAL?

A. The punitive LD clause has two important effects: 1) it uneconomically skews the actual purchased costs of wind energy upward, as the presence of the LD clause leads WTG suppliers to incorporate this artificial risk into their firm energy quantity election and thus their pricing; and 2) it could lead to BC Hydro rejecting some cost-effective WTG-based projects.

The combination of these two effects could lead to BC Hydro paying more for the last increment or increments of Call energy than it may otherwise need to pay. A rejected tender or tenders may actually have been able to bid a lower-priced offer than the highest-price accepted tender if the LD clause as currently structured and applicable to WTG Call energy was not included in the EPA, or was modified to reflect WTG's inherent forward-looking output uncertainty.

Q. DO THE SHORTFALL LIQUIDATED DAMAGES PROVISIONS PROPERLY REFLECT THE COST TO BC HYDRO IF ACTUAL DELIVERED ENERGY FROM WTG PROVIDERS IS LESS THAN 90% OF TENDERED FIRM ENERGY AMOUNTS?

A. Not necessarily. The LD clause represents an artificial risk, as noted earlier, because BC Hydro is not necessarily at risk to purchase more (or sell less) energy externally just because a given WTG generator does not meet 90% of its firm energy amount for a given month.

There will likely be months in which firm energy is delivered at the contracted amount, and considerable non-firm energy is also sold to BC Hydro, at a discount. This allows for a "carryover" of excess energy into the next month that helps to buffer the effect of any shortfalls that may arise in that next month. Also, because of the presence of non-firm energy from other Call suppliers, including other WTGs, it is likely that BC Hydro actually receives more energy in any given month than just the total Call "firm energy" amount.

Thus it is unlikely that BC Hydro actually has to increase its purchases or reduce it sales to external regions on a one-for-one basis proportionate to the firm shortage amounts in order accommodate the lower level of WTG firm energy supply.

For reasons provided in the section of this testimony addressing the firming premium, BC Hydro's buffering capability due to its large hydro storage coupled with non-firm energy from Call suppliers reduces its intra-year risk of needing to purchase more (or sell less) energy from (to) the external market. Therefore, the extent of potential need for liquidated damages from WTG suppliers to cover a shortfall of monthly delivered energy is likely overestimated and thus the LD clause particulars are more severe than necessary.

Q. WHAT DO YOU RECOMMEND IN REGARDS TO THE SHORTFALL LD CLAUSE?

A. I recommend that the shortfall LD clause as currently structured be reconsidered for the next BC Hydro energy call.

At least four options exist for restructuring the LD clause: 1) it could be restructured to address firm energy shortages over an incrementally greater interval, such as multi-month (2 months) or seasonal (3 month), especially for Call suppliers (like WTGs) who are inherently unable to accurately predict *monthly* output in far-forward time frames such as months or years but can more accurately predict output over lengthier periods; 2) it could be restructured to apply on an annual basis for WTG providers; 3) it could be eliminated altogether for WTG providers; or 4) the 10% bandwidth factor could be raised.

A fair LD clause can likely lead to WTG election of greater shares of firm energy from a given WTG plant, less exposure to non-firm discount prices, and a reduced overall bid price; all the while limiting BC Hydro's exposure to increased opportunity costs of external sales or purchases. A fair LD clause is needed to mitigate the risk that an independent power producer that relies on purchased fuel might, in the absence of the LD clause, curtail deliveries below its monthly firm commitment merely because its fuel price is relatively high.

V. OPERATIONAL COSTS OF WIND INTEGRATION

Q. WHAT DO YOU ADDRESS IN THIS SECTION?

A. In this section I describe the way incremental operational costs sometimes associated with wind turbine generation operation on a power system have been considered in other North American regions.

Q. WHAT DO YOU MEAN BY THE "OPERATIONAL COSTS OF WIND INTEGRATION"?

A. The operational costs of wind integration are the incremental costs associated with operating a power system that includes variable output WTG resources. Specifically, these costs are the ancillary service costs associated with ensuring reliable system operation, including regulation/frequency response, load following and contingency reserve ancillary services, and near-term (i.e., day-ahead timeframe) scheduling and unit commitment impacts.

Q. ARE OPERATIONAL COSTS OF WIND RESOURCE INTEGRATION ACCOUNTED FOR IN BC HYDRO'S F2006 CALL FOR TENDER?

A. Not directly. There are no explicit estimates provided by BC Hydro of the operational costs of integrating wind energy into the BC Hydro system. Thus, the evaluation of resources considered in the F2006 Call for Tenders does not directly account for the operational costs of wind integration. BC Hydro addresses related temporal issues such as the use of a delivery time adjustment[8] to recognize the time value of delivered energy relative to baseline annual energy; and further, adjustments to the bid prices are given for green credits, hourly firming, interconnection/transmission costs, and greenhouse gas obligations. However, there is no direct incorporation of the impacts a wind generation project may have on the costs to operate the BC Hydro generation and transmission system.

[8] Standard Form, Large Project EPA, Appendix 3, Section 3.4.

Q. HAS BC HYDRO CALCULATED THE OPERATIONAL COSTS TO INTEGRATE WIND RESOURCES IN BRITISH COLUMBIA?

A. No. British Columbia Transmission Corporation's (BCTC's) consultant[9] produced a series of reports on wind integration, but the reports were primarily qualitative and did not quantify the operational costs of wind integration for the BC system. The consultant's last report[10] did note that wind integration is not expected to present significant technical challenges in BC, given the Province's extensive reliance on large hydro resources, which provide a large installed capacity base and exhibit good load following attributes.[11]

Q. WHAT ARE THE COSTS TO INTEGRATE WIND IN OTHER REGIONS?

A. The cost to integrate wind is highly region-specific. A number of integration cost studies have been performed and an abbreviated summary of those results are presented in Attachment 4. A review of these studies indicates that incremental costs associated with provision of ancillary services and day-ahead unit commitment and scheduling for systems with incremental wind generation range from a low of zero to highs of up to US$10-11/MWh, with one outlier reporting at US$18/MWh. However, most of the studies report values in the low single digits, i.e., under US$5/MWh in total for ancillary service costs.

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[9] Electric Systems Consulting, ABB Inc.

[10] Wind Farm Integration in British Columbia – Stages 3: Operational Impact, Electric Systems Consulting, ABB Inc., Issued March 4, 2005, revised March 28, 2005. Available on the BCTC website at http://www.bctc.com/the_transmission_system/engineering_reports_studies/.

[11] See for example in the ABB Stage 3 report cited above the *Conclusions and Recommendations* section (p29) and the *Impact on the BC System* section, especially the load following and frequency control section (p23).

Q. ARE THE COSTS PRESENTED IN THESE STUDIES DIRECTLY COMPARABLE TO EACH OTHER, OR DIRECTLY APPLICABLE TO BRITISH COLUMBIA?

A. Not in general. In particular, most of the studies are of systems that do not have the level of hydro resources that BC has. Also, the system-wide characteristics and the wind penetration assumptions (i.e., WTG as a percentage of installed capacity base) vary tremendously across these studies. The assumptions for wind forecast accuracy range from "none" to "state-of-the–art" to "perfect" forecasting. Wind penetration assumptions can range from just a few percent to as much as 30% of installed capacity. Another consideration is the coincidence of wind patterns with load patterns, and this can vary widely between systems and even within or across systems (e.g., New York's offshore wind potential in its higher-cost downstate zone is more aligned with its load patterns than upstate New York wind patterns are with their zonal load patterns)[12].

In short, it is difficult to generalize from other regions' studies or experience when estimating the range of costs to reliably integrate incremental wind generation, especially when comparing hydro-based systems to systems that are more heavily reliant on fossil fuel generation technologies. Finally, the costs will be strongly affected by the temporal and spatial characteristics of the wind resource projects throughout a system.

Q. GIVEN THESE CAVEATS, ARE THESE STUDIES OF VALUE TO BC?

[12] GE Energy Consulting. The Effects Of Integrating Wind Power On Transmission System, Planning, Reliability, And Operations Report On Phase 2: System Performance Evaluation. Prepared for The New York State Energy Research And Development Authority, March 2005.

A. Yes. Collectively, they demonstrate the wide range of costs and show that actual region-specific costs will indeed depend immensely on the assumptions. They represent a body of knowledge of how wind generation operation can incrementally effect system operation, and the range of costs of such effects.

Q. CAN YOU ESTIMATE IN GENERAL TERMS WHERE BC HYDRO IS LIKELY TO FALL IN THE RANGE OF THESE STUDIES?

A. Yes, although detailed modeling studies would be required to estimate the actual range. In my judgment, incremental operational costs for wind integration in the BC Hydro system are likely to be or fall close to zero, which is the bottom of the range presented by the studies summarized in Attachment 4, especially for an initial period when overall BC wind penetration as a percentage of installed capacity is low. The reasons have been discussed previously, but they relate primarily to the significant storage and exceptional load following capability of the large hydropower resources on the system.

Q. DO YOU RECOMMEND FURTHER STUDY BY BC HYDRO ON THE COSTS TO INTEGRATE WIND INTO THE BC HYDRO SYSTEM?

A. Yes. BC Hydro should conduct further, detailed technical studies to evaluate the effect of WTG operation on its system in both the near term and over the longer term, respecting and anticipating the evolution of WTG, transmission system and control technologies and incorporating lessons learned and analytical approaches used in other jurisdictions.[13] Such studies should include assessments at increased levels of WTG penetration, such as 5%, 10%, 20%, and higher (as noted in Attachment 4, European system studies assess penetration levels at as high as 30%; and some European systems, for example Denmark and Germany, exhibit wind penetration levels that at times equal or exceed 100% of energy requirements[14]). In particular, the studies should carefully review the technical capabilities of the BC Hydro system to respond to any required increases in regulation, load following, or other ancillary services. The studies should also address the way in which wind forecasting tools can reduce near-term uncertainties of WTG operational output, and consider the spatial and temporal diversity associated with WTG operation at multiple sites around the Province.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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[13] See, for example, IEEE Power and Energy Magazine, November/December 2005 Issue, multiple articles on "Working with Wind, Integrating Wind into the Power System"; and "Wind Power in Power Systems", Thomas Ackermann, Royal Institute of Technology, Stockholm, Sweden, Editor. John Wiley and Sons Ltd., 2005.

[14] Presentation by Thomas Ackermann at Utility Wind Integration Group "A Short Course on the Integration and Interconnection of Wind Power Plants Into Electric Power Systems", presented in Providence, Rhode Island, September 2006.

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SUMMARY

Mechanical engineer and energy economics analyst with 20 years experience in the energy industry. Activities focused primarily on electric power industry issues, especially economic and technical analysis of transmission pricing structures, wholesale electricity markets, and assessment and implementation of demand-side alternatives.

In-depth understanding of the complexities of, and the interrelationships between, the technical and economic dimensions of the electric power industry in the US and Canada, including the following areas of expertise:

- Wholesale energy and capacity provision under market-based and regulated structures.
- Extent of competitiveness of existing and potential wholesale market structures.
- Transmission use pricing, encompassing congestion management, losses, LMP and alternatives, financial and physical transmission rights; and transmission asset pricing (embedded cost recovery tariffs).
- Physical transmission network characteristics; related generation dispatch/system operation functions; and technical and economic attributes of generation resources.
- RTO and ISO tariff and market rules structures and operation.
- FERC regulatory policies and initiatives, including those pertaining to RTO and ISO development and evolution.
- Demand-side management, including program implementation and evaluation; and load response presence in wholesale markets.
- Building energy end-use characteristics, and energy-efficient technology options.
- Fundamentals of electric distribution systems and substation layout and operation.
- Energy modeling (spreadsheet-based, GE MAPS and online DOE-2 residential).
- State and provincial level regulatory policies and practices, including retail service and standard offer pricing structures.
- Gas industry fundamentals including regulatory and market structures, and physical infrastructure.

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. 2004 – Present. Senior Associate
Responsibilities include consulting on issues of energy economics, analysis of electricity utility planning, operation, and regulation, including issues of transmission, generation, and demand-side management. Provide expert witness testimony on various wholesale and retail electricity industry issues. Specific project experience includes the following:

- Evaluation of pollutant emission reduction plans and the introduction of an open access transmission tariff in Nova Scotia.
- Evaluation of the merger of Duke and Cinergy with respect to Indiana ratepayer impacts.
- Review of the termination of a Joint Generation Dispatch Agreement between sister companies of Cinergy.
- Assessment of the potential for an interstate transfer of a DSM resource between the desert southwest and California, and the transmission system impacts associated with the resource.
- Analysis of various transmission system and market power issues associated with the proposed Exelon-PSEG merger.
- Assessment of market power and transmission issues associated with the proposed use of an auction mechanism to supply standard offer power to ComEd native load customers.
- Review and analysis of the impacts of a proposed second 345 kV tie to New Brunswick from Maine on northern Maine customers.

Tabors Caramanis & Associates, Cambridge, MA 1996 -2004. Senior Associate.

- Provided expert witness testimony on transmission issues in Ontario and Alberta.
- Supported FERC-filed testimony of Dr. Tabors in numerous dockets, addressing various electric transmission and wholesale market issues.
- Analyzed transmission pricing and access policies, and electric industry restructuring proposals in US and Canadian jurisdictions including Ontario, Alberta, PJM, New York, New England, California, ERCOT, and the Midwest. Evaluated and offered alternatives for congestion management methods and wholesale electric market design.
- Attended RTO/ISO meetings, and monitored and reported on continuing developments in the New England and PJM electricity markets. Consulted on New England FTR auction and ARR allocation schemes.
- Evaluated all facets of Ontario and Alberta wholesale market development and evolution since 1997. Offered congestion management, transmission, cross-border interchange, and energy and capacity market design options. Directly participated in the Ontario Market Design Committee process. Served on the Ontario Wholesale Market Design technical panel.
- Member of TCA GE MAPS modeling team in LMP price forecasting projects.
- Assessed different aspects of the broad competitive market development themes presented in the US FERC's SMD NOPR and the application of FERC's Order 2000 on RTO development.

- Reviewed utility merger savings benchmarks, evaluated status of utility generation market power, and provided technical support underlying the analysis of competitive wholesale electricity markets in major US regions.
- Conducted life-cycle utility cost analyses for proposed new and renovated residential housing at US military bases. Compared life-cycle utility cost options for large educational and medical campuses.
- Evaluated innovative DSM competitive procurement program utilizing performance-based contracting.

Charles River Associates, Boston, MA, 1992-1996. **Associate**. Developed DSM competitive procurement RFPs and evaluation plans, and performed DSM process and impact evaluations. Conducted quantitative studies examining electric utility mergers; and examined generation capacity concentration and transmission interconnections throughout the US. Analyzed natural gas and petroleum industry economic issues; and provided regulatory testimony support to CRA staff in proceedings before the US FERC and various state utility regulatory commissions.

Rhode Islanders Saving Energy, Providence, RI, 1987-1992. **Senior Commercial/Industrial Energy Specialist**. Performed site visits, analyzed end-use energy consumption and calculated energy-efficiency improvement potential in approximately 1,000 commercial, industrial, and institutional buildings throughout Rhode Island, including assessment of lighting, HVAC, hot water, building shell, refrigeration and industrial process systems. Recommended and assisted in implementation of energy efficiency measures, and coordinated utility DSM program efforts.

Fairchild Weston Systems, Inc., Syosset, NY 1985-1986. Facilities Engineer. Designed space renovations; managed capital improvement projects; and supervised contractors in implementation of facility upgrades.

Narragansett Electric Company, Providence RI, 1981-1984. Supervisor of Operations and Maintenance. Directed electricians in operation, maintenance, and repair of high-voltage transmission and distribution substation equipment.

EDUCATION

Boston University, M.A. Energy and Environmental Studies, 1992
Resource Economics, Ecological Economics, Econometric Modeling

Clarkson University, B.S. Mechanical Engineering, 1981
Thermal Sciences

Additional Professional Training
Completed coursework in Solar Engineering; Building System Controls; and Cogeneration at Worcester Polytechnic Institute and Northeastern University (1984, 1988-89).
Completed Illuminating Engineering Society courses in lighting design (1989).
Utility Wind Integration Group, Short Course on Integration and Interconnection of Wind Power Plants Into Electric Power Systems (2006).

SUMMARY OF TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

TESTIMONY

Maine Joint Legislative Committee on Utilities, Energy and Transportation. Testimony before the Committee in support of an Act to Encourage Energy Efficiency (LD 1931) on behalf of the Maine Natural Resources Council, February 9, 2006. The testimony and related analysis focused on the costs and benefits of increasing the system benefits charge to increase the level of energy efficiency installations by Efficiency Maine.

Nova Scotia Utilities and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of Air Emissions Strategy Capital Projects. Filed Jaunary 30, 2006. The testimony addressed the application for approval of installation of a flue gas desulphurization system at NSPI's Lingan station and a review of alternatives to comply with provincial emission regulations.

New Jersey Board of Public Utilities. Direct and Surrebuttal Testimony filed before the Commission addressing the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations (the proposed merger), BPU Docket EM05020106. Joint Testimony with Bruce Biewald and David Schlissel. Filed on behalf of the New Jersey Division of the Ratepayer Advocate, November 14, 2005 (direct) and December 27, 2005 (surrebuttal).

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission addressing the proposed Duke – Cinergy merger. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 42873, November 8, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Ameren's proposed competitive procurement auction (CPA). Testimony filed on behalf of the Illinois Citizens Utility Board in Dockets 05-0160, 05-0161, 05-0162. Direct Testimony filed June 15, 2005; Rebuttal Testimony filed August 10, 2005.

Illinois Commerce Commission. Direct and Rebuttal Testimony filed before the Commission addressing wholesale market aspects of Commonwealth Edison's proposed BUS (Basic Utility Service) competitive auction procurement. Testimony filed on behalf of the Illinois Citizens Utility Board and the Cook County State's Attorney's Office in Docket 05-0159. Direct Testimony filed June 8, 2005; Rebuttal Testimony filed August 3, 2005.

Indiana Utility Regulatory Commission. Responsive Testimony filed before the Commission addressing a proposed Settlement Agreement between PSI and other parties in respect of issues surrounding the Joint Generation Dispatch Agreement in place between PSI and CG&E. Filed on behalf of the Citizens Action Coalition of Indiana, Consolidated Causes No. 38707 FAC 61S1, 41954, and 42359-S1, August 31, 2005.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission in a Fuel Adjustment Clause (FAC) Proceeding concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E, and related issues of PSI lost revenues from inter-company energy pricing policies. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 38707 FAC 61S1, May 23, 2005.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 41954, April 21, 2005.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Eastern Maine Electric Cooperative, Inc.'s Petition for a Finding of Public Convenience and Necessity to Purchase 15 MW of Transmission Capacity from New Brunswick Power and for Related Approvals. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2005-17, July 19, 2005.

State of Maine Public Utilities Commission. Testimony filed before the Commission on an Analysis of Maine Public Service Company Request for a Certificate of Public Convenience and Necessity to Purchase 35 MW of Transmission Capacity from New Brunswick Power. Testimony filed jointly with David Schlissel and Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2004-538 Phase II, April 14, 2005.

Nova Scotia Utilities and Review Board (UARB). Testimony filed before the UARB on behalf of the UARB staff, In The Matter of an Application by Nova Scotia Power Inc. for Approval of an Open Access Transmission Tariff (OATT). Filed April 5, 2005. The testimony addressed various aspects of OATTs and FERC's *pro forma* Order 888 OATT.

Texas Public Utilities Commission. Testimony filed before the Texas PUC in Docket No. 30485 on behalf of the Gulf Coast Coalition of Cities on CenterPoint Energy Houston Electric, LLC. Application for a Financing Order, January 7, 2005. The testimony addressed excess mitigation credits associated with CenterPoint's stranded cost recovery.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-2002-0120, et al., Review of the Transmission System Code (TSC) and Related Matters, Detailed Submission to the Ontario Energy Board in Response To Phase I Questions Concerning the Transmission System Code and Related Matters, October 31, 2002, on behalf of TransAlta Corporation; and Reply Comments for same, November 21, 2002. Related direct and reply filings in response to the Ontario Energy Board's "Preliminary Propositions" on TSC issues in May and June, 2003.

Alberta Energy and Utilities Board. Testimony filed before the Alberta Energy and Utilities Board, in the Matter of the Transmission Administrator's 2001 Phase I and Phase II General Rate Application, no. 2000135, pertaining to Supply Transmission Service charge proposals. Joint testimony filed with Dr. Richard D. Tabors. March 28, 2001. Testimony filed on behalf of the Alberta Buyers Coalition.

Ontario Energy Board. Testimony filed before the Ontario Energy Board, RP-1999-0044, Critique of Ontario Hydro Networks Company's Transmission Tariff Proposal and Proposal for

Alternative Rate Design, January 17, 2000. Testimony filed on behalf of the Independent Power Producer's Society of Ontario.

MAJOR PROJECT WORK – BY CATEGORY

Electric Utility Industry Regulatory and Legislative Proceedings

For the staff of the Nova Scotia Utility and Review Board, conducted an economic analysis of the proposed installation of flue gas desulphurization equipment by Nova Scotia Power, Inc., and alternatives to the installation, to conform to Nova Scotia provincial emission regulations. (2005-2006)

For the staff of the Nova Scotia Utility and Review Board, analyzed a proposed Open Access Transmission Tariff by Nova Scotia Power, Inc. (2005)

For the Maine Office of Public Advocate, analyzed multiple aspects of the proposed installation of a second 345 kV tie line between Maine and New Brunswick. The analyses focused on the impacts to Northern Maine electric consumers. (2005)

Electric Utility Industry Restructuring

For the Citizens Action Coalition of Indiana, analyzed the proposed merger between Duke and Cinergy, with a focus on global protections available for PSI ratepayers and the allocation of projected merger cost and savings. (2005)

For the Citizens Action Coalition of Indiana, analyzed the termination of the Joint Generation Dispatch Agreement between Cincinnati Gas and Electric and PSI with a focus on PSI ratepayer impacts. (2005)

For TransAlta Energy Corporation, developed an issues and information paper on recent Ontario and Alberta market development efforts, focusing on the likely high-level impacts associated with day-ahead and capacity market mechanisms considered in each of those regions. (2004)

For a wholesale energy market stakeholder, participate in New England and PJM RTO markets and market implementation committee meetings, review and summarize material, and advocate on behalf of client on selected market design issues. (2004) Performed similar activities for separate client in New England. (2001)

For a group of potential generation investors in Ontario, analyzed the government's proposed wholesale and retail market design changes and produced an advocacy report for submission to the Ontario Ministry of Energy. The report emphasized, among other things, the importance of retaining a competitive wholesale market structure. (2004)

For a large midwestern utility, supported multiple rounds of direct and rebuttal testimony to the US FERC by Dr. Richard Tabors on the proposed start-up of LMP markets in the Midwest ISO utility service territories. Testimony substance included PJM-MISO seams concerns, FTR allocation options, grandfathered transactions incorporation, FTR and energy market efficiency impacts, and other wholesale market and MISO transmission tariff design issues. Testimony also included quantitative analysis using GE MAPS security-constrained dispatch model runs. (2003-2004)

For the Independent Power Producers Society of Ontario, with TCA Director Seabron Adamson, developed a position paper on resource adequacy mechanisms for the Ontario electricity market. (2003)

For TransAlta Energy Corp., provided direct and reply testimony to the Ontario Energy Board on the Transmission System Code review process. Analyzed and reported on transmission "bypass" and network cost responsibility issues. (2002-2003)

For a commercial electricity marketer in Ontario, with TCA staff, analyzed Ontario market rules for interregional transactions, focusing primarily on the Michigan and New York interties, and assessed the current Ontario electricity market policy related to "failed intertie transactions". (2002)

For ESBI Alberta Ltd., then Transmission Administrator (TA) of Alberta, served as a key member of the TCA team exploring congestion management issues in the Province, and providing guidance to the TA in presenting congestion management options to Alberta stakeholders, with a particular focus on new transmission expansion pricing and cost allocation issues. (2001)

For a coalition of power producers and marketers in Alberta, filed joint expert witness testimony with Dr. Tabors on the nature of certain transmission access charges associated with supply transmission service. (2001)

For a prospective market participant, served as a core member of the project team that developed summary reports on the New York, New England and PJM wholesale electricity spot market structures. The reports focused on market structure fundamentals, historical transmission flow patterns, forecasted transmission congestion and costs, transmission availability and FTR valuation and market results. (2001)

For the ERCOT ISO, served as a key TCA team member helping to develop and assemble a set of protocols to guide the principles, operation and settlement of the forthcoming Texas competitive wholesale electricity market. (2000)

For the Independent Power Producer's Society of Ontario, served as expert witness and filed evidence with the Ontario Energy Board supporting an alternative transmission tariff design, and critiquing Ontario Hydro Networks Company's (OHNC) proposed rate structure. Also a member of OHNC's Advisory Team on net versus gross billing issues and a leading proponent of a progressive, embedded-generation-friendly tariff structure. (1999-2000)

For a large midwestern utility, designed transmission tariff and wholesale market structures consistent with the proposed establishment of an Independent Transmission Company paradigm for transmission operations. (1999-2000)

For a coalition of independent power producers and marketers in Alberta, helped develop evidence submitted by Dr. Tabors and Dr. Steven Stoft with the Alberta Energy and Utilities Board supporting an alternative to ESBI's proposed transmission tariff. The evidence critiqued the fairness and efficiency of ESBI's proposed tariff, and offered a simple alternative to deal with Alberta's near-term southern supply shortage. (1999)

For Enron Canada Corp., provided ongoing technical support and policy advice during the tenure of the Ontario Market Design Committee (MDC). Presented material on congestion pricing before the committee, and submitted technical assessments of most wholesale market development issues. (1998-1999)

Member of the Ontario Wholesale Market Design Technical Panel. The panel's responsibilities included refinement of the wholesale market design as specified by the Market Design Committee, and specification of the market's initial operating requirements. Also served on two sub-panels: bidding and scheduling; and ancillary services. (1998-1999)

For Enron Canada Corp, assessed the generation markets in Ontario and Alberta and recommended policies for maximizing competitive market mechanisms and minimizing stranded cost burdens. Authored reports on stranded costs in Ontario, and on the legislated hedges structure in Alberta. (1997 - 1998)

For an independent power producer, assessed New England markets for electricity and assisted in valuation of generation assets for sale. (1997)

In support of testimony filed by CCEM (Coalition for Competitive Electric Markets) with the FERC, assessed alternative transmission pricing and wholesale market structures proposed for the NY, NE and PJM regions. The filings proposed market mechanisms to produce competitive wholesale electric energy markets and zonal-based transmission pricing structures. (1996-1997)

Electric Utility Mergers and Market Power Analysis

For the New Jersey Ratepayer Advocate, provided jointly sponsored expert testimony (with Bruce Biewald and David Schlissel) on the potential market power effects of the proposed Exelon-PSEG merger. (2005-2006)

For the Citizens Utility Board (Illinois), provided direct and rebuttal testimony on potential market power and transmission impacts and other issues associated with ComEd's proposal to procure standard offer power through a market-based auction process. (2005)

For the Citizens Utility Board and other clients (Illinois), provided direct and rebuttal testimony on issues associated with Ameren's proposal to procure standard offer power through a market-based auction process. (2005)

In support of FERC-filed testimony by Dr. Richard Tabors, conducted a detailed examination of the accessibility of transmission service for wholesale energy market participants on the American Electric Power and Central and Southwest transmission systems. This included evaluating all transmission service requests made over the OASIS for the first six months of 1998 for the two utility systems, and a subsequent, more detailed assessment of AEP's transmission system use during all of 1998. (1998-1999)

For a US western electric utility, served as a member of the team that conducted detailed production cost modeling and strategic market assessment to determine the extent or absence of market power held by the client. (1998)

For an independent power producer, supported FERC-filed testimony on market power issues in the New York State energy and capacity markets. This included detailed supply-curve assessment of existing generation assets within the New York Power Pool. (1997)

Worked with a local economic consulting firm for a Western State public agency in conducting an analysis of the projected savings of a series of proposed electric and gas utility mergers. (1997)

For a southwestern utility company, supported CRA in conducting an analysis of the competitive effects of a proposed electric utility merger. For a northwestern utility company, analyzed the competitive effects of a proposed electric utility merger. (1995-1996)

For the Massachusetts Attorney General's Office, conducted a study of the potential for market power abuse by generators in the NEPOOL market area. (1996)

DSM Competitive Procurement and DSM Evaluation

For the Natural Resources Council of Maine, analyzed the costs and benefits of increasing the system benefits charge (SBC) in Maine to increase efficiency installations by Efficiency Maine. Testimony before the Maine Joint Legislative Committee on Energy and Utilities. (2006)

For Southern California Edison (SCE), working as a sub-contractor to Sargent and Lundy, analyzed the potential for an interstate transfer of a DSM resource between the desert southwest and California. For the same project, also analyzed transmission impacts of various alternatives to replace power supply from the currently closed Mohave generation station for SCE. (2005)

For two separate large New England utilities, conducted impact evaluations of large commercial and industrial sector DSM programs. (1994-1996)

For a New England utility, worked on the project team developing a set of DSM evaluation master plans for incentive-type and third-party-contracting type DSM programs (1994)

For EPRI, wrote an overview of the status of DSM information systems and the potential effects of an increasingly competitive utility environment. (1993)

For two separate large New England utilities, helped to develop competitive procurement documents (DSM RFPs) for filing before the Massachusetts Department of Public Utilities. (1993, 1994)

For a midwestern utility, conducted a trade ally study designed to determine the influence of trade allies on the market for energy efficient lighting and motor equipment. (1992-1993)

DSM Implementation

Conducted detailed site visits and suggested efficiency improvement strategies for over 1,000 commercial, industrial and institutional buildings in Rhode Island. Performed end-use energy analysis and coordinated implementation of improvements. Worked with local utility DSM program personnel to educate building owners on DSM program opportunities. (1987-1992)

Energy Modeling

For various clientele, worked closely with the TCA GE MAPS modeling group on various facets of security-constrained dispatch modeling of electric power systems across the US and Canada. Specific tasks included assisting in designing MAPS model run parameters (e.g., base case and alternative scenarios specification); proposing modeling designs to clients; supporting input data gathering; interpreting model results; and writing summary reports, memos & testimony describing the results. (2002-2004)

For a group of potential electricity supply investors in Ontario, modeled the impact of proposed generation plant phaseout trajectories on investment requirements for new supply in Ontario. (2004)

For the Independent Power Producer's Society of Ontario, conducted a retrospective quantitative analysis of the Ontario market energy and ancillary service prices during the 15 months of the new wholesale market to determine the extent of infra-marginal rents available that could have supported entry for new generation. (2003)

In support of proposals to the US Dept. of Defense for military housing privatization, performed DOE-2 model runs using an online tool; and created a spreadsheet modeling tool to analyze the efficiency and cost effectiveness of new and renovated residential construction for base housing. Performed life-cycle utility cost analysis and prepared energy plans specifying building shell, equipment and appliance efficiency measures at 15 separate Army, Navy, and Air Force installations around the nation. (2001-2003)

For the Independent Power Producer's Society of Ontario, conducted a rate impact analysis of Ontario Hydro Networks Company proposed transmission tariff. (1999-2000)

For the University of Maryland at Baltimore, conducted a life-cycle cost analysis of alternative proposals for district-type thermal energy provision, comparing existing steam delivery systems to new hot-water systems. (1998)

For the UMass Medical Center (Worcester), conducted an energy use and cost allocation analysis of a large hospital complex to assist in choosing among electric and thermal energy supply options. (2000)

For an independent power producer, developed a spreadsheet-based tool to assess the rate impact of a clean coal facility in Maryland compared to alternative gas-fired supply options. (1996-1997)
For a private consulting firm, examined electric end-use and generation capacity information in seven industry energy models and reported the sensitivities of each model to varying levels of input aggregation. (1995)

For a private industrial firm in Virginia, developed a Monte-Carlo simulation-based spreadsheet model to solve a capital budgeting problem involving long-term choice of industrial boiler equipment. (1995)

For a New England utility, developed a spreadsheet model to help determine economic decision-making processes used by energy service companies when delivering third-party procured DSM. (1995)

Petroleum and Natural Gas Industry Analysis
For a private independent power producer, conducted an analysis of the rate impacts of the Warrior Run clean coal (fluidized bed combustion) power plant in Maryland under various assumptions of natural gas prices and environmental regulation scenarios. (1996-1997)

For a British consulting firm, researched and presented findings on the current status of natural gas restructuring efforts in the US and their impact on regional US markets for power generation. (1996)

For a Canadian law firm representing Native Canadian interests, conducted a detailed analysis of natural gas netback pricing for Alberta gas into US Midwest and West Coast markets over a thirty-year period. (1995)

For a US natural gas pipeline consortium, performed an econometric analysis of the demand for natural gas in the state of Florida. (1992-1993)

PAPERS, PUBLICATIONS AND PRESENTATIONS

Interstate Transfer of a DSM Resource: New Mexico DSM as an Alternative to Power from Mohave Generating Station. Jointly authored with Tim Woolf, Bill Steinhurst and Bruce Biewald. To be presented at the 2006 ACEEE Summer Study on Energy Efficiency in Buildings and published in the proceedings. (2006)

SMD and RTO West: Where are the Benefits for Alberta? Keynote Paper prepared for the 9th Annual Conference of the Independent Power Producers Society of Alberta, with Dr. Richard D. Tabors, March 7, 2003.

A Progressive Transmission Tariff Regime: The Impact of Net Billing, presentation at the Independent Power Producer Society of Ontario annual conference, November 1999.

Tariff Structure for an Independent Transmission Company, with Richard D. Tabors, Assef Zobian, Narasimha Rao, and Rick Hornby, TCA Working Paper 101-1099-0241, November 1999.

Transmission Congestion Pricing Within and Around Ontario, presentation at the Canadian Transmission Restructuring Infocast Conference, Toronto, June 2-4, 1999.

The Restructured Ontario Electricity Generation Market and Stranded Costs. An internal company report presented to the Ontario Ministry of Energy and Environment on behalf of Enron Capital and Trade Resources Canada Corp., February 1998.

Alberta Legislated Hedges Briefing Note. An internal company report presented to the Alberta Department of Energy on behalf of Enron Capital and Trade Resources Canada, January 1998.

Generation Market Power in New England: Overall and on the Margin. Presentation at Infocast Conference: New Developments in Northeast and Mid-Atlantic Wholesale Power Markets, Boston, June 1997.

The Market for Power in New England: The Competitive Implications of Restructuring. Prepared for the Office of the Attorney General, Commonwealth of Massachusetts, by Tabors Caramanis & Associates with Charles River Associates, April 1996. R. Fagan was a key member of the team that produced the report.

Estimating DSM Impacts for Large Commercial and Industrial Electricity Users. Lead investigator and author, with M. Gokhale, D.S. Levy, P.J. Spinney, G.C. Watkins. Presented at The Seventh International Energy Program Evaluation Conference, Chicago, Illinois, August 1995, and published in the Conference Proceedings.

Sampling Issues in Estimating DSM Savings: An Issue Paper for Commonwealth Electric. Prepared with G.C. Watkins, Charles River Associates. Report for COM/Electric System, filed with the MA Dept. of Public Utilities (MDPU), April 28, 1995, Docket # DPU 95-2/3-CC-l.

Demand-side Management Information Systems (DSMIS) Overview. Electric Power Research Institute Technical Report TR-104707. Robert M. Fagan and Peter S. Spinney, principal investigators, prepared by Charles River Associates for EPRI, January 1995.

Impact Evaluation of Commonwealth Electric's Customized Rebate Program. With P.J. Spinney and G.C. Watkins. Charles River Associates, Initial and Updated Reports, April 1994, April 1995, and April 1996.1995 updated report filed with the MDPU, April28, 1995, Docket # DPU 95-2/3-CC-I. The initial report filed with the MDPU, April 1, 1994.

Northeast Utilities Energy Conscious Construction Program (Comprehensive Area): Level I and Level II Impact Evaluation Reports. With Peter S. Spinney (CRA) and Abbe Bjorklund (Energy

Investments). Charles River Associates Reports prepared for Northeast Utilities, June and July 1994.

The Role of Trade Allies in C&I DSM Programs: A New Focus for Program Evaluation, Paper authored by Peter J. Spinney (Charles River Associates) and John Peloza (Wisconsin Electric Power Corp.). Presented by Bob Fagan at the Sixth International Energy Evaluation Conference, Chicago, Illinois, August 1993.

Resume dated May 2006.

British Columbia Utilities Commission Information Request No. **3.104.1** Dated: **July 21, 2005** British Columbia Hydro & Power Authority Response issued **August 12, 2005**	Page 1
British Columbia Hydro & Power Authority **2005 Resource Expenditure and Acquisition Plan ("REAP")**	

104.0 Reference: Exhibit B-11, Direct Testimony of Mary Hemmingsen, p. 7

Ms. Hemmingsen's testimony states: "The basis for the additional value provided by a project that provides firm energy on an hourly resolution is the levelized cost of Revelstoke Unit #5, inclusive of forgone system benefits to BC Hydro, a proxy for BC Hydro's cost of incremental intra-day system capacity."

104.1 Please provide a detailed analysis showing the derivation of the levelized cost of Revelstoke Unit #5 as the underpinning for the additional value of hourly firm energy, with examination of the value attributable to forgone system benefits, and transportation to the Lower Mainland.

RESPONSE:

The details of the levelized cost of Revelstoke 5 that was used to underpin the additional value of hourly firm energy are as follows:

For the purpose of estimating the increased value of hourly firm as compared to monthly firm, the expected cost and the foregone system benefits of dedicating facilities to shape the monthly firm energy to hourly firm energy were utilized.

- **For this purpose, Revelstoke 5 was selected as the proxy as it is the next planned incremental capacity on the system that has the capability to increase the combined reservoir operating flexibility and shift energy from monthly firm to hourly firm and dispatchable;**
- **Given the service is to shape and firm energy to an hourly time scale, the costs of providing the service are allocated across all hours of the year.**

Starting from the spreadsheet attachment to BC Hydro's response to BCUC IR 2.85.0:

Revelstoke 5	**$/kW-yr**
Total Cost	**24.9**
Total Benefits	**(27.6)**
Net Cost	**(2.7)**

As identified in the response to BCUC IR 2.85.0, the cost, net of system benefits, of Revelstoke 5 is negative (i.e. identified system benefits outweigh the cost of constructing and operating the unit).

When evaluating an alternative use for any asset, the alternative use must be sufficient to cover the higher of the cost (cost-based approach); or the foregone opportunity value (value-based approach).

From a cost-based approach, BC Hydro used the pure capacity cost of Revelstoke 5 of $24.9/kW-yr. This means that, from a cost standpoint, the shaping service offered would have to cover such cost.

- **This would result in an hourly cost-based benchmark of $2.85/MW-h (i.e. $24,900 / 8,760), when the capacity cost is apportioned across all hours of the year.**

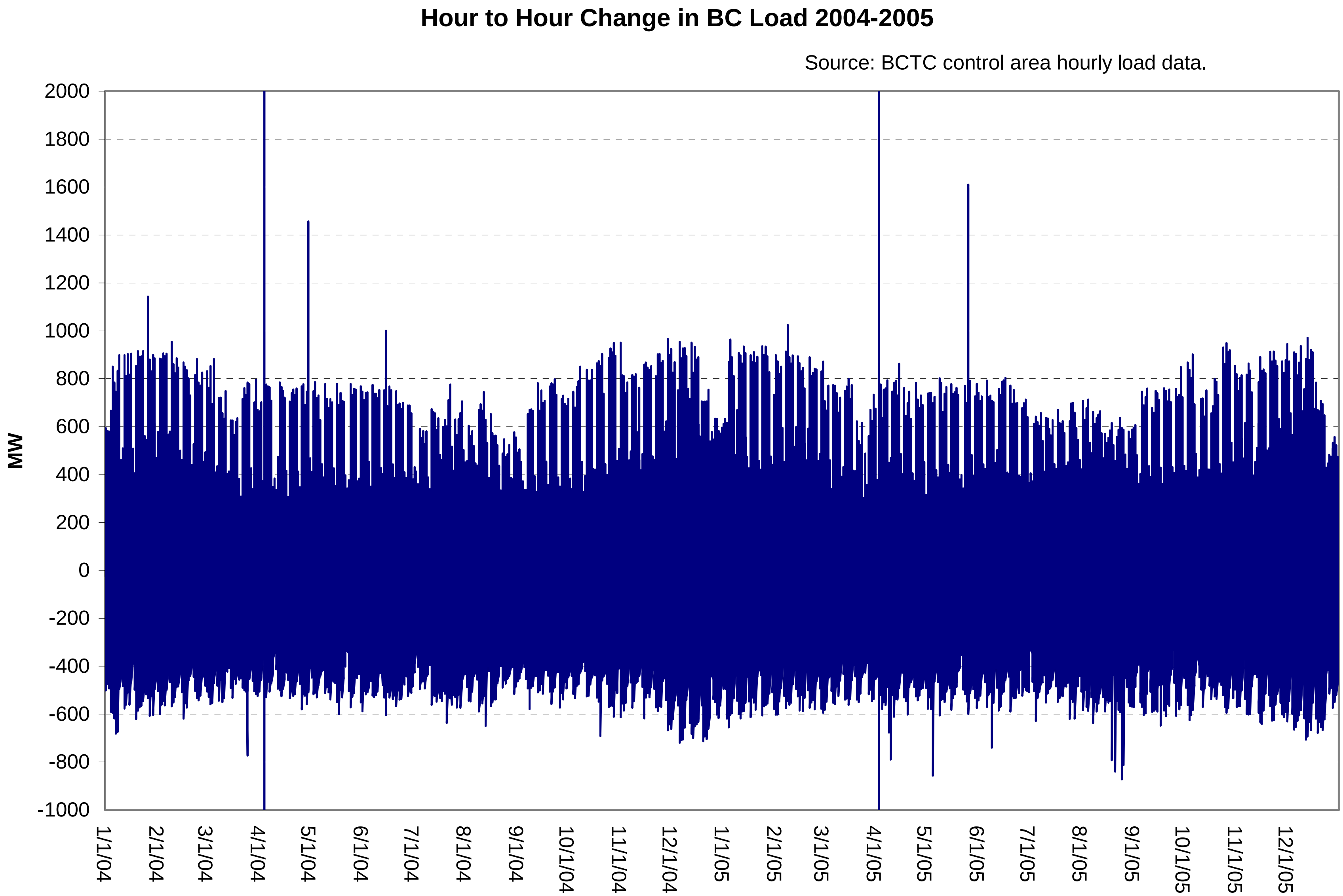
From a value-based approach, and expressly the reference to "inclusive of foregone system benefits", BC Hydro has conservatively identified the initial system benefits of Revelstoke 5 to be $27.6/kW-yr. This means that BC Hydro would have to perceive at least this much value if it were to utilize the plant for another purpose.

- **This would result in an hourly value-based benchmark of $3.15/MW-h (i.e. $27,600 / 8,760), when the system benefits value is apportioned across all hours of the year.**

The minimum that BC Hydro could value Revelstoke 5 if it were to use the resource for alternative purposes would be the maximum of the two calculated values, or, in this case $3.15/MW-h.

For the purposes of this F2006 Call, BC Hydro valued the firm hourly credit at $3.00/MWh recognizing that:

- **the system benefits identified in the response to BCUC IR 2.85.0 were conservative; and**
- **a dispatchable resource, such as Revelstoke 5, will have somewhat more value than a project that provides firm energy on an hourly basis.**



Hour to Hour Change in BC Load 2004-2005
Source: BCTC control area hourly load data.
MW
2000
1800
1600
1400
1200
1000
800
600
400
200
0
-200
-400
-600
-800
-1000
1/1/04
2/1/04
3/1/04
4/1/04
5/1/04
6/1/04
7/1/04
8/1/04
9/1/04
10/1/04
11/1/04
12/1/04
1/1/05
2/1/05
3/1/05
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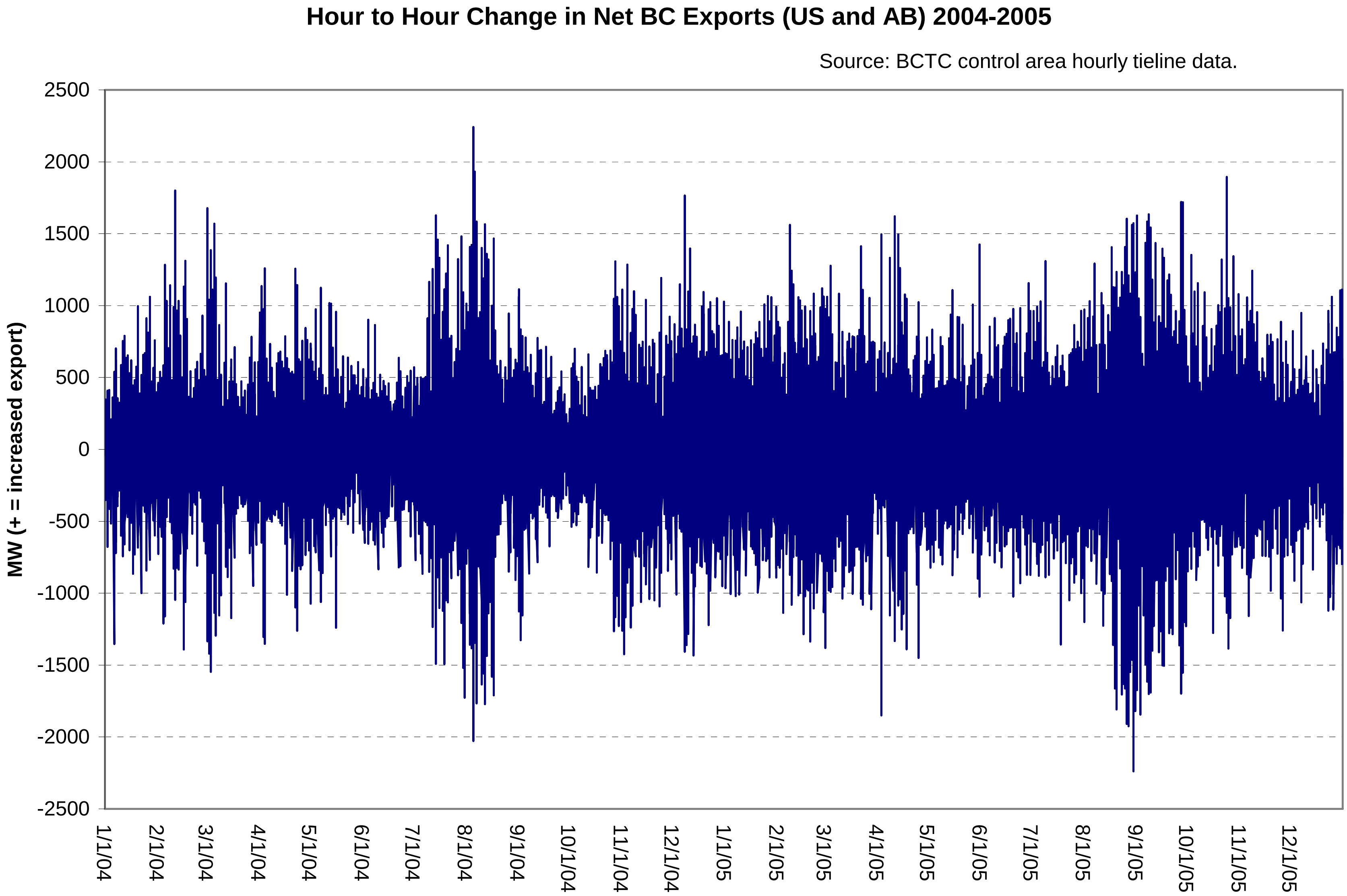
Hour to Hour Change in Net BC Exports (US and AB) 2004-2005
Source: BCTC control area hourly tieline data.
MW (+ = increased export)
2500
2000
1500
1000
500
0
-500
-1000
-1500
-2000
-2500
1/1/04
2/1/04
3/1/04
4/1/04
5/1/04
6/1/04
7/1/04
8/1/04
9/1/04
10/1/04
11/1/04
12/1/04
1/1/05
2/1/05
3/1/05
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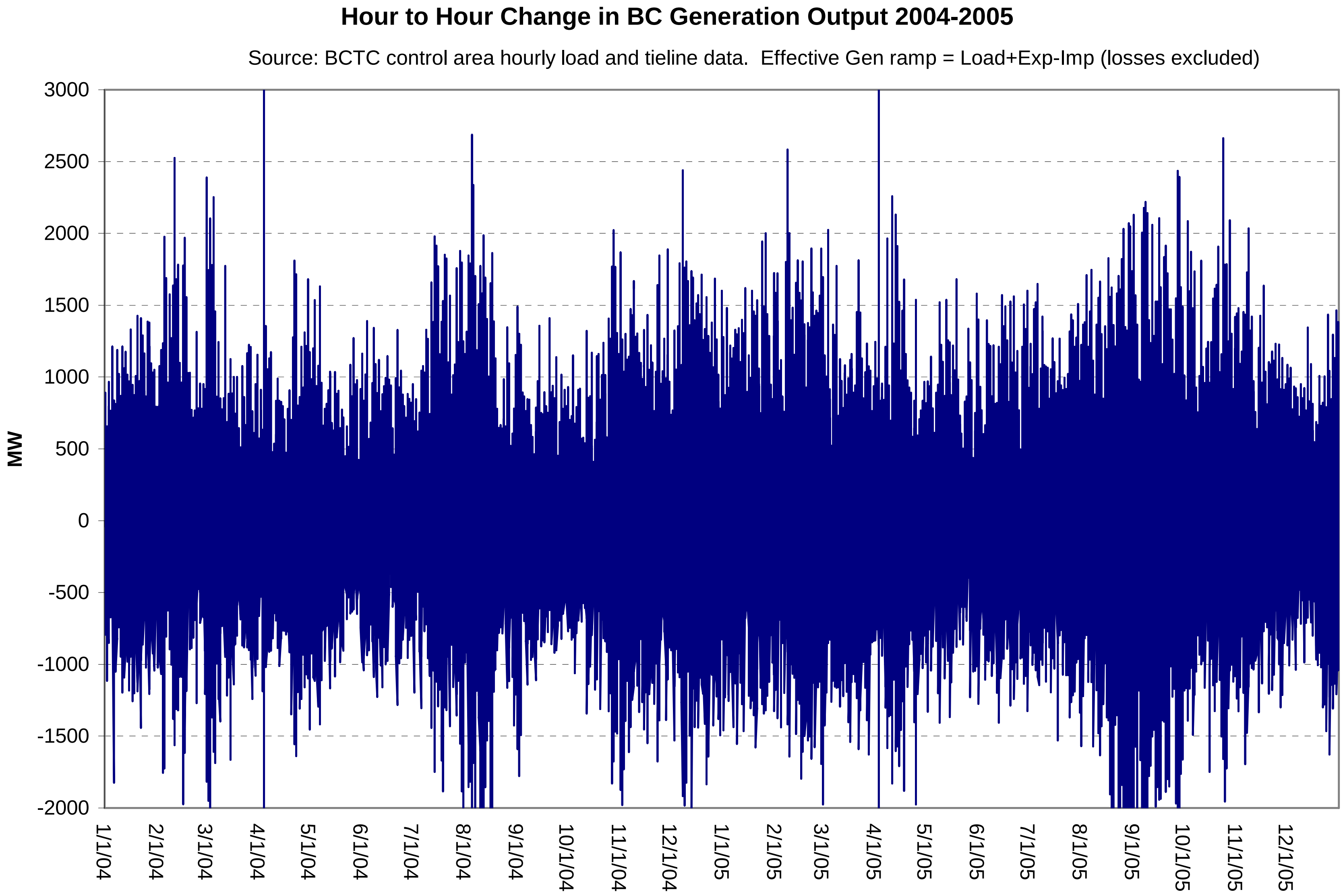
11/1/05
12/1/05



Hour to Hour Change in BC Generation Output 2004-2005
Source: BCTC control area hourly load and tieline data. Effective Gen ramp = Load+Exp-Imp (losses excluded)
MW
3000
2500
2000
1500
1000
500
0
-500
-1000
-1500
-2000
1/1/04
2/1/04
3/1/04
4/1/04
5/1/04
6/1/04
7/1/04
8/1/04
9/1/04
10/1/04
11/1/04
12/1/04
1/1/05
2/1/05
3/1/05
4/1/05
5/1/05
6/1/05
7/1/05
8/1/05
9/1/05
10/1/05
11/1/05
12/1/05

Estimated Operational Costs of Wind Integration

Integration Cost Study or Reference	Date Published	Date Results Applicable	System Wind Penetration Level	Estimated Operational Cost Impact ($/MWH)	Comments
GE for The New York State Research and Development Authority: Phase 2 Study	2005	2008	3,300 MW 10% of NY 2008 Peak	$1.50	Roughly 25% of the system cost reductions between the "no wind" and "actual wind" cases results from the ability to predict the wind ahead of time and reflect its generation in the commitment of the rest of the system. The existing forecast accuracy seems to pick up 90% of that difference, but the remaining 10% is worth about $1.50/MWh of wind generation.
Xcel Energy and the Minnesota Department of Commerce Wind Integration Study	2004	2010	1500 MW (15%)	$4.60	Wind generation exhibits significant and mostly uncontrollable variability on all of the time scales relevant to power system operations – seconds, minutes, hours, days; The ability to predict or forecast wind generation for forward time periods is lower than that for conventional resources, and declines as the forecast horizon moves outward.
NREL: Wind Power Impacts on Electric Power System Operating Costs: Summary and Perspective on Work to Date	2004		See below	See below	
UWIG - XCEL North	2003		280 MW on an 8,000 MW peak system	$1.85	Summing the cost impact results for the components assessed over the three timeframes and using the forecast error range of +/- 50%, the impact of integrating XCEL NORTH's existing 280-MW wind plant is approximately $1.85/MWh of wind generation.
BPA - Eric Hirst	2002		1,000 MW (14,000 MW peak)	$1.47-2.27	
Hirst - theoretical plant in PJM in summer	2002		103 MW on 52,000 MW peak system	$3.30	
Hirst - theoretical plant in PJM in winter	2002		104 MW on 52,000 MW peak system	$0.75	
Pacificorp	2003		20%	$5.50	
Utility Wind Integration Group (UWIG) Utility Wind Integration State of the Art	2006	Not specified, but includes studies with 2008-2010 timeframes.	Wind penetrations of up to 20% of system peak demand	Up to $5.00/MWh	"Fluctuations in the net load (load minus wind) caused by greater variability and uncertainty introduced by wind plants have been shown to increase operating costs by up to about $5/MWH at wind penetration levels up to 20%. The greatest part of this cost is associated with the uncertainty introduced into day-ahead unit commitment due to the uncertainty in day-ahead forecasts of realtime wind production."
LBL Mark Bolinger and Ryan Wiser: Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans	2005	2002	See below	Zero to $11.00	Integration costs are expected to vary by utility and by the level of wind power penetration.
Pacificorp 2003 IRP			24%	$5.60	Based on its own studies of integrating wind into its system, initial $5.6/MWh is split approximately evenly between incremental operating reserves and imbalance costs.
Pacificorp 2004 IRP			14%	$4.50	Costs in 2004 IRP are lower due to lower assumed cost of reserves.
PGE IRP			28%	$10.00	Initial IRP estimate based on the cost of not only integrating wind, but also firming and shaping wind into a "flat" (baseload) product. This adds to the expense, and is arguably not technically necessary because load itself is not flat.
Idaho Power IRP					Did not model integration costs, but does note that the Snake River hydroelectric system affords it considerable flexibility in economically integrating wind, implying that costs are expected to be low.

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Avista IRP 2003			5%	$2-18	Presuming that Avista fears that integration costs will be at or above the upper end of its estimated range, as suggested by the 75 MW (4% of peak load) cap placed on new wind in its 2003 RFP, its cost assumptions appear to be high relative to other available literature estimates.
Avista IRP 2005				$5-11	
PSE 2005 IRP			8%	$4	
Eric Hirst: Integrating Wind Energy with the BPA Power System: Preliminary Study	2002		1,000 MW	1.37-2.17	Roughly speaking, a 1000-MW wind farm might increase (or decrease) the amount of capacity BPA needs online at any time by about 100 MW, depending on the accuracy of the DA wind forecast.
UWIG: Wind Power Impacts on Electric Power System Operating Costs: Summary and Perspective on Work to Date	2004		See below	See below	
BPA			7%	1.47-2.27	
WE Energies			4%	$1.90	
WE Energies			29%	$2.92	
Great River			4%	$3.19	
Great River			16.60%	$4.53	
NREL at EWEA 2006 Conference: Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States	2006		See below	See below	
California RPS Integration	2006		4%	$0.46	Regulation impacts only. Load following impacts "minimal".
XCEL-PSCo	2006		10% / 15% / 20%	$3.72 / 4.97 / 8.87	Cost includes gas storage costs for gas burn for reserves.
AESO Incremental Impact on System Operations with Increased Wind Power Penetration (Ph. I and Ph. II)	2005 / 2006	2004 / Post 2006		No cost data given	Ph. I: Assessed wind at 895 MW (10%), 1,445 MW (15%), 1,994 MW (20%). "Operational performance issues apparent at the 895 MW level…and mitigating measures required to maintain system performance at acceptable levels". Measures include wind forecasting, increasing reserves, increasing transmisison reliabiltiy margins and placing constraints on wind power facilities. Ph. II: Calulated "lost opportunity" wind power curtailments, wind ramp rates, and additional regulating reserve requirements. No cost computation.
Eltra, ISO for western Denmark: Costs of Wind Power Integration into Electricity Grids (Western Denmark)	2004	2006	21% energy, 32% installed capacity from wind	$10 Euro / MWH	
Holttinen 2004: The impact of large scale wind production on the Nordic Electricity System	2004		10% / 20%	1.00 Euro / 2.00 Euro	
Impact of Wind Generation in Ireland: ESB National Grid	2004 /2005 / 2006		1500 MW (15%) 2500 MW (20-25%) 3500 MW (30%)	5.10 / 8.0 / 11.3 Euros	

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SEI: Study on Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity	2004	2010	1300 MW / 1950 MW	0.2 / 0.5 Euro in operating reserve costs	The additional cost of operating reserve is relatively small and likely to be to less than €0.20/MWh in 2010 if there is 1300MW of wind or €0.50/MWh with 1950MW
ILEX Energy Consulting: system costs in UK	2002 / 2003	2010-2020 (costs in 2002 lbs)	20% / 30%	9.3 / 10.8 pounds/MWH	Costs for wind in Scotland and northern England.
Power UK: A shift to wind is not unfeasible	2003		10%/15%/20%	2.38/2.65/2.85 pounds/MWH	Increased reserve costs.
UK Energy Research Center: The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network	2006		20%	£3 - £5/MWh under British conditions	Based on the difference between the contribution to reliability made by intermittent generation plant and the contribution to reliability made by conventional generation plant. This comparison should be drawn between plants that provide the same amount of energy when operated at maximum utilisation. This provides a measure of the cost of maintaining system reliability and is in addition to the direct costs of intermittent plant.
The Carbon Trust Impact Study: UK	2003 / 2004		500 MW wind in UK / 10% wind in UK	0.19-.18 / 1.35-2.25 pounds/MWH	These are extra "balancing costs." Balancing costs differ from Reserve costs in that the latter is contracted for in advance in order to ensure support is available if called upon, while balancing costs are applied as a result of actual system balancing activities and are on the whole charged to those causing the imbalances.
European Wind Energy Association (EWEA): Large scale integration of wind energy in the European power supply: analysis, issues and recommendations (December 2005)	2005			0 Euros to 4 Euros per MWh	Large national studies in UK, Germany and Denmark confirm that system integration costs, under the most conservative assumptions (low gas price compare to the current level, low to zero social benefit of CO2) are only a fraction of the actual consumer price of electricity and are in the order of magnitude of €0 to €4/MWh (consumer level).