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April 18, 2008

BY COURIER (10 COPIES) AND EMAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
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Toronto, Ontario M4P 1E4
Fax: (416) 440-7656
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Dear Ms. Walli:

Re: Pollution Probe – Intervenor Evidence
EB-2007-0050 – Hydro One – Bruce-Milton Transmission Reinforcement Project

Pursuant to Procedural Order No. 8, please find enclosed intervenor evidence on behalf of Pollution Probe's experts.

Yours truly,

B. Alexander

Basil Alexander

BA/ba

Encl.

cc: Applicant and Intervenors per Procedural Order No. 8

Before the Ontario Energy Board

EB-2007-0050
Hydro One Networks Inc.

Leave To Construct A Transmission Reinforcement Project Between The Bruce Power Facility And Milton Switching Station, All In The Province Of Ontario (Bruce-Milton Transmission Reinforcement Project)

Direct Evidence of

Robert M. Fagan, Synapse Energy Economics
and
Peter J. Lanzalotta, Lanzalotta Associates

Prepared on behalf of Pollution Probe

April 18, 2008

Table of Contents

Section I – Introduction, Description and Purpose of Evidence

Introduction

This evidence is presented in four parts.

First, this introductory section presents the qualifications of the expert witnesses appearing on behalf of Pollution Probe. A brief description of the form and statement of the purpose of the evidence is then provided.

A summary of the evidence is then given, including the recommendations of Mr. Fagan and Mr. Lanzalotta.

Next, an analysis and critique of the Hydro One Networks Inc. (HONI) application is provided. This includes our explanation in support of the use of "interim" measures, on a permanent basis, to reinforce the Southwest Ontario transmission system without the need for constructing a new 500 kV double circuit line between Bruce and Milton.

Last, we conduct an assessment of the use of near term and "interim" measures for reinforcing the transmission system and increasing the transfer capacity away from Bruce for Bruce area generation resources. This assessment includes review of the use of series compensation and generation rejection schemes as reliable approaches to increase the utilization of the transmission system without the need for constructing a new double circuit 500 kV line. This assessment is in support of the recommendations in Section II of our evidence, recognizing that permanent use of series compensation and generation rejection schemes is a reliable and cost effective way of increasing the transfer capacity away from Bruce and allowing for delivery of energy from Bruce area generation in support of the Province's goals as directed by the Minister of Energy.

Qualifications

<u>Peter J. Lanzalotta, Principal, Lanzalotta & Associates LLC</u>

Mr. Lanzalotta is a Principal of Lanzalotta & Associates LLC, which was formed in January 2001. Prior to that, he was a partner of Whitfield Russell Associates, with which he had been associated since March 1982. His areas of expertise include electric utility system planning and operation, electric service reliability, cost of service, and utility rate design. He is a registered professional engineer in the states of Maryland and Connecticut. His prior professional experience is described in the attached appendices.

He has been involved with the planning, operation, and analysis of electric utility systems and with utility regulatory matters, including reliability-related matters, certification of new facilities, cost of service, cost allocation, and rate design, as an employee of and as a consultant to a number of privately- and publicly-owned electric utilities, regulatory agencies, developers, and electricity users over a period exceeding thirty years.

He has been involved in a number of projects focused on electric utility transmission and distribution system reliability. He has worked for many years on behalf of the City of Chicago on electric reliability-related matters, and has been engaged by various government offices and agencies in the states of Delaware, Maryland, New Jersey, and Pennsylvania to help address electric service reliability concerns.

He has presented expert testimony before the Federal Energy Regulatory Commission and before regulatory commissions and other judicial and legislative bodies in 21 states, the District of Columbia, and the Provinces of Alberta and Ontario. His clients have included utilities, regulatory agencies, ratepayer advocates, independent producers, industrial consumers, the federal government, and various city and state government agencies. The proceedings in which he has testified are listed in the attached appendices.

<u>Robert M. Fagan, Senior Associate, Synapse Energy Economics, Inc.</u>

Robert Fagan is a mechanical engineer and energy economics analyst with over 20 years experience in the energy industry. His activities have focused primarily on electric power industry issues, especially economic and technical analysis of transmission pricing structures, wholesale electricity markets, assessment and implementation of demand-side alternatives, analysis of wind resource integration into electric power systems, and various state-level electric regulatory policy issues. His professional experience is described in the appendices.

His work demonstrates an 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.

Description and Purpose of Evidence

The purpose of this evidence is to critically examine HONI's application proposing to build a new Bruce to Milton double circuit 500 kV line. It addresses issues of project need, project alternatives, near term and interim measures, and reliability and quality of service.

The evidence is provided in three major sections, Sections II, III and IV. Section II summarizes our evidence and findings. Section III analyzes and critiques key aspects of the Hydro One Networks Inc. (HONI) application. It also includes recommendations for the Province to install near term and "interim" measures but to not approve the proposed double circuit Bruce to Milton line. The last Section IV provides an assessment of the technical attributes of series compensation and generation rejection as measures to use to improve the utilization of the transmission system without having to construct the proposed new line.

Section II: Summary of Evidence

1. As detailed below and in our evidence, we make the following major conclusions and recommendations:
    a. There is no need to rush approval of the proposed new line now prior to a more deliberate review of the OPA's Integrated Power System Plan. It may be prudent to speedily consider implementation of "interim" reinforcement measures, but not approving the proposed new line now on a fast-track basis will not hinder achievement of the Province's energy goals. Review of the IPSP will instead allow for more careful analysis of the likelihood of Bruce B refurbishment and the options for wind resources in areas outside of the Bruce region.
    b. There is no need to design a transmission system to deliver 100% of available installed capacity in this location (i.e. the Bruce area) 100% of the time, especially given the technical characteristics of wind generation (which operates at substantially less than 100% of capacity most of the time) and given the nature and historical operation of aggregate Bruce nuclear resources (which also historically operated at substantially less than 100% of capacity most of the time).
    c. Use of series compensation and generation rejection will instead allow for the most economical utilization of the existing transmission system. In contrast, if the proposed new line was approved, the system's technical capabilities would be increased so that there would be significant capacity that would only be used rarely. In addition, there is no reliability or economic reason to operate the transmission system at levels so much lower than what its technical capabilities would be (unlike if series compensation and generation rejection were used instead).
    d. The benefits of the proposed line do not appear to outweigh the costs if Bruce B refurbishment does not occur, and, even with refurbishment, the net benefits may be negative depending on the assumptions one makes concerning locked-in energy. In addition, while there appears to be some improvement in the line loss factor due to the proposed line, this improvement is not sufficient to justify the line given its significant cost.
2. The proposed new line is not necessary to deliver the energy and capacity of the existing and planned resources in the Bruce area. Use of a reinforced grid (referred to as "interim" measures by HONI in its application), including series compensation and generation rejection schemes, can serve to reliably and economically deliver energy and capacity from the Bruce region. Such incremental transmission system reinforcement is the most economical approach to increasing transfer capacity from the region in support of the Province's electricity sector goals. While under some exceptional circumstances, a small amount of energy may be available but not deliverable, it is not economically reasonable to construct the transmission system to deliver 100% of all such available energy 100% of the time, particularly since the costs likely outweigh the benefits.
3. HONI's graphical presentation of transmission limits and generation quantities in the Bruce area masks the operational realities of actual available generation. The application

assumes that nuclear and wind resources are at 100% of their maximum continuous [capacity] rating (MCR). However, aggregate resource output or availability is what actually matters in order to deliver energy and capacity from the Bruce area. For example, an examination of the historical output patterns for the Bruce nuclear station's 24 years of operation shows that its aggregate capacity has been much less than 100%. This contrast illustrates why it is misleading to use 100% of the station's MCR when assessing transmission delivery needs. Similarly, output patterns from wind resources (which are fairly well-understood) demonstrate that aggregate output for the entire Bruce area wind resources would likely never approach 100%. In order to assess transmission needs, more reasonable values should be used that are considerably less than this, and such values should account for average annual wind resource capacity factors of 29%.

4. Contrary to HONI claims, it does not appear that the proposed project benefits likely outweigh its cost. Based on HONI's own assessment, the assumptions made about the aggregate capacity factor of the Bruce nuclear station can swing the project benefits from net positive to net negative.

5. HONI's computation of the quantity of undelivered energy is based on non-transparent (i.e. unexplained and untestable) assumptions. Such assumptions include: the capacity factor of aggregate generation at Bruce nuclear station; the capacity factor of aggregate existing or planned wind resources in the Bruce region; and the allowable transmission capacity away from the Bruce area. Information (and lack of information) provided by HONI unfortunately does not allow for independent testing of HONI's estimate.

6. Finally, despite assertions to the contrary, series compensation and generation rejection schemes do not need to be limited to "interim" operation. These measures are proven technologies and operating practices, and they allow for a fuller utilization (and therefore more economical operation) of the transmission system.

Section III: Analysis and Critique of HONI Application

Delivering Bruce Area Nuclear and Wind Energy Without Proposed Line

Using maximum continuous rating (MCR) values for all Bruce area nuclear and wind generation masks the underlying operational realities and overestimates the amount of away from Bruce area transmission capacity required to deliver existing and planned nuclear and wind energy resources.

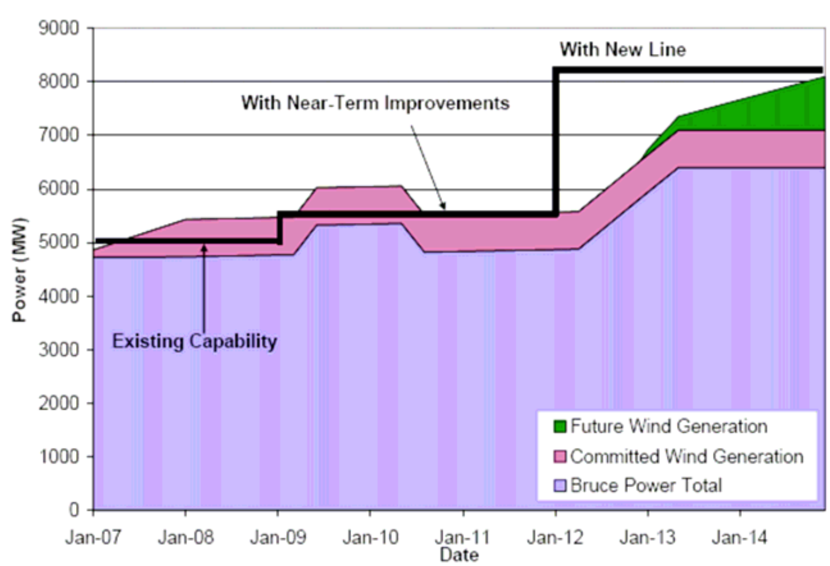
The underlying nature of aggregate resource output for both the nuclear and wind resources in the Bruce area is such that it is highly unlikely, if not almost technically impossible given wind variation, that in aggregate all such resources would be operating at their maximum continuous rating at any one time. However, this is the framework on which Hydro One is presenting its case in favor of the proposed Bruce-Milton 500 kV double circuit.

HONI's application materials on "Transmission Alternatives Considered", e.g. Figure 1, Exhibit B, Tab 3, Schedule 1, page 2 ("Figure 1: Bruce Area Available Generation and Transmission Capacity (2007 – 2014)", reproduced below), distort the operational reality of the Bruce area transmission and resource system by implying that the full MCR rating of Bruce area aggregate generation is always available for energy delivery. This is not the case.

Figure 1. HONI Depiction of Bruce Area Generation and Transmission

double-circuit line directly connecting the Bruce Power Complex to the GTA. The forecast resource capacity and the transmission capabilities associated with the near-term and long-term solutions are shown in Figure 1 below.

Figure 1: Bruce Area Available Generation & Transmission Capacity (2007 – 2014)



Source: OPA

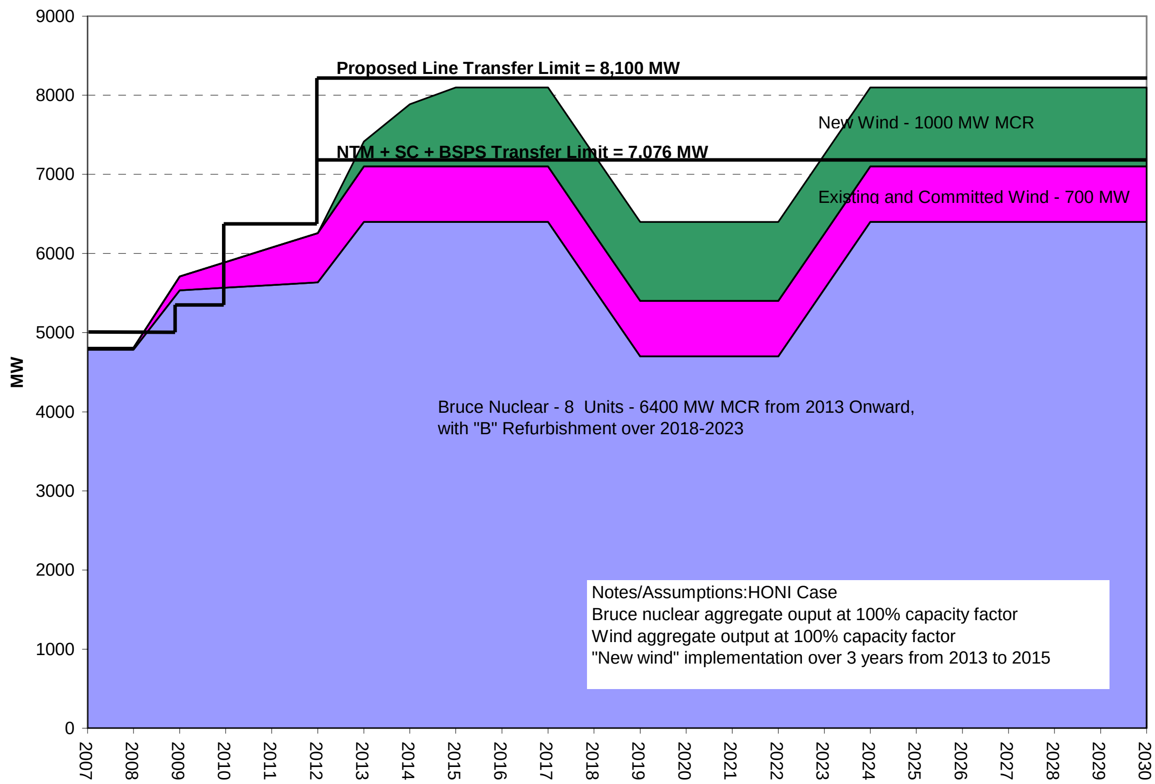
Source: HONI, Exhibit B, Tab 3, Schedule 1, Page 2, Updated November 30, 2007

This particular figure also excludes the increased transmission capacity available with the "interim" arrangements, i.e. the series compensation and generation rejection system alternative. It also depicts the system only to 2015, even though OPA's IPSP goes through 2027.

The 7,000+ MW transfer capability associated with an upgraded transmission system incorporating near-term and "interim" improvements will have the capacity to deliver the output of the Bruce nuclear station, existing and committed wind, and new wind resources with minimal "locked-in" energy effects because at any given time, and over any given period, all "installed capacity" in the Bruce area is unlikely to be available for operation at 100% of MCR.

Looking more carefully at the range of possible generation output illustrates the operational reality of the power system in the Bruce area and demonstrates the sufficiency of the transmission system to deliver energy without the proposed line. The figures below show first HONI's depiction, and then the capacity of the transmission system with near and "interim" improvements with the underlying aggregate Bruce area resources operating at aggregate average capacity factors of 95% for the aggregate Bruce nuclear generation and 50% for the aggregate wind resources in the region.[1] Both figures show the system for the circumstance where Bruce B nuclear station is refurbished, even though this has yet to be established. This high-level snapshot indicates that near-term improvements plus series compensation and use of the Bruce Special Protection System allows for enough capacity to transmit the Bruce area resources when one assumes aggregate capacity factors of 95% for Bruce nuclear (8 units, 6,400 MW MCR) and 50% for wind (existing, committed and future wind = 1,700 MW).

Figure 2. HONI Depiction of Need for Line Using Full MCR Values and Bruce "B" Refurbishment



[1] These two reference points are chosen to illustrate the sensitivity of the transmission need to aggregate supply resource capacity factor assumptions. They are not intended as absolutes. Indeed, based on historical performance, the 95% CF for Bruce nuclear can be considered overly optimistic. Average annual wind capacity values are projected by OPA at 29%, with average summer peak values lower (21%) and winter peak values higher (34%).

Figure 3. Alternative Assumptions: Depiction of Need for Bruce Area Line Using Bruce Nuclear Station Aggregate CF = 95% and Wind Aggregate CF = 50%

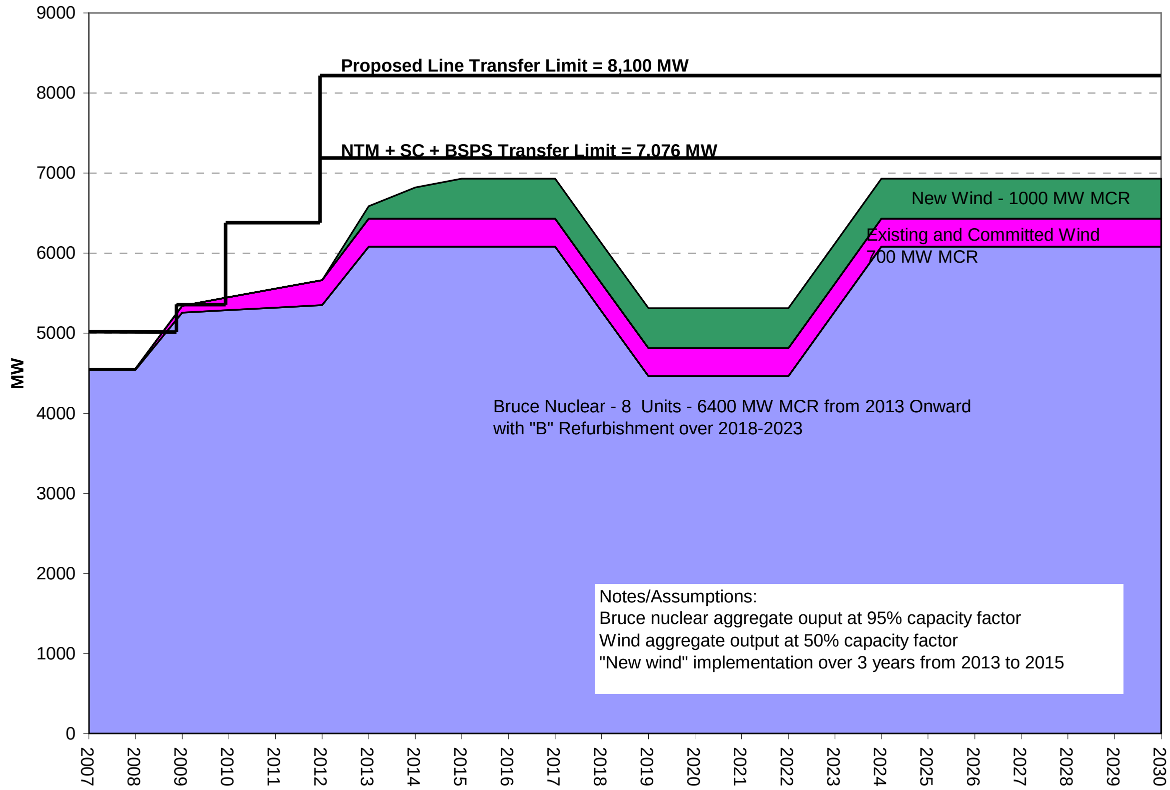


Figure 3 illustrates the importance of capacity factor assumptions when considering the need for the proposed line.

Impact of No or Only Partial Refurbishment of Bruce B Units

If the refurbishment of the Bruce B complex is not done, or is only partially executed – two instead of four units – the proposed line becomes even more uneconomical, as “locked-in” or “undeliverable” energy is estimated by Synapse to be zero in all periods after the shutdown of the first of the four Bruce B units (in 2018, according to HONI). In that circumstance, constructing the proposed line would likely be particularly imprudent, since excessive transmission capacity would result.

The two graphs below illustrate the ability of the reinforced transmission system to deliver the energy from the aggregate Bruce area generation if Bruce B refurbishment does not occur, using the same capacity factor assumptions as in the graph above (Figure 3), and if refurbishment of 2 of the 4 units at Bruce B is undertaken in the 2018-2019 timeframe.

Figure 4 below illustrates the significant drop in Bruce area generation that would occur if Bruce B refurbishment did not occur; and it shows the extent of “excess” transmission capacity that arises under that circumstance. Figure 5 below illustrates that with partial refurbishment at Bruce B (two of the four units), more than adequate transmission capacity exists without the proposed new line.

Figure 4. Bruce Area Operation in the Absence of Refurbishment of the Bruce B Nuclear Station, Using 95% CF (Bruce nuclear) and 50% CF (wind) Assumptions

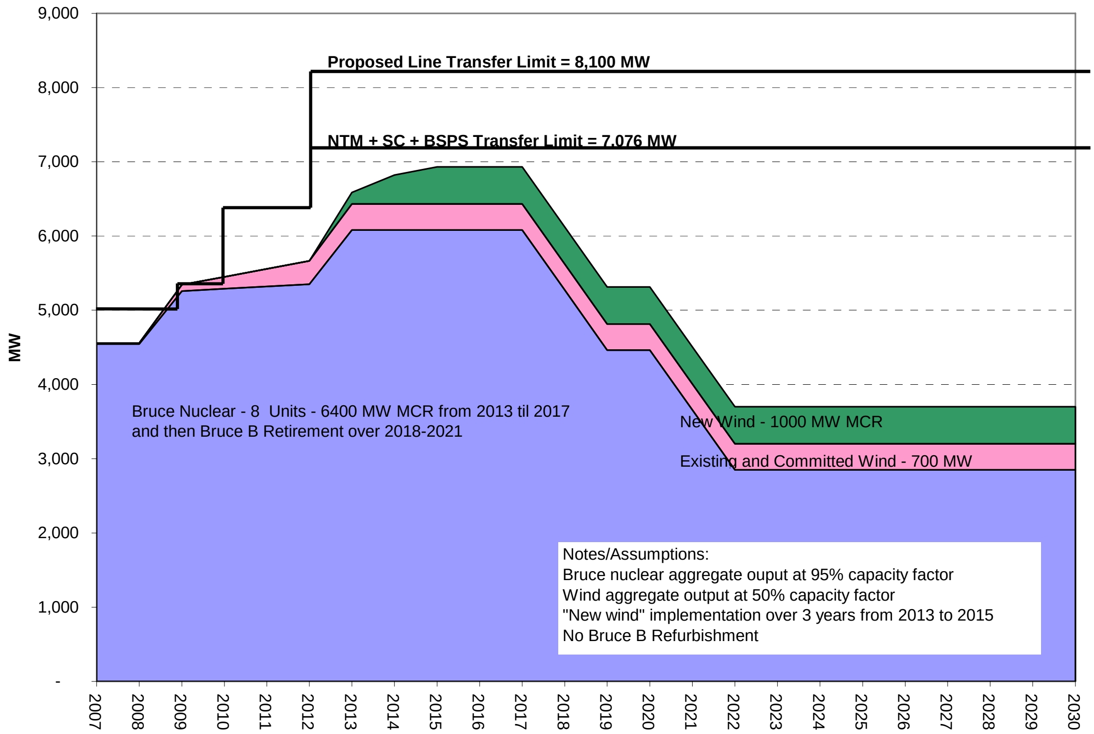
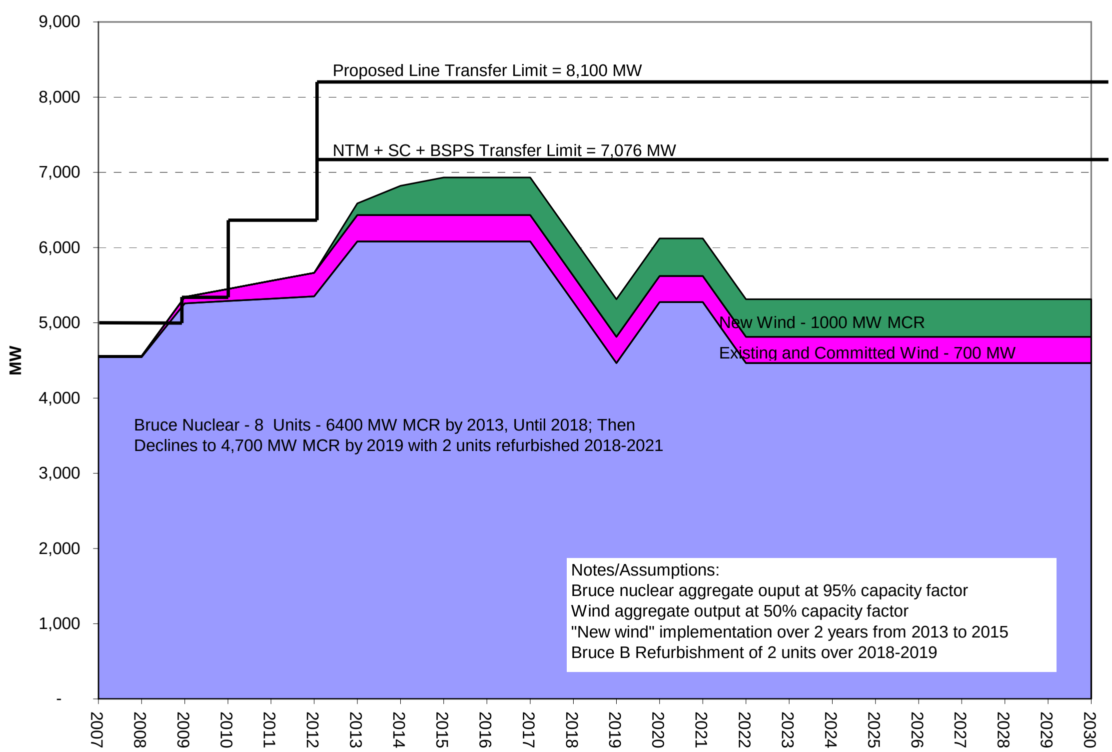


Figure 5. Bruce Area Operation with Partial Refurbishment (2 Units) of the Bruce Nuclear Station Using 95% CF (Bruce nuclear) and 50% CF (wind) Assumptions



Sensitivity of Bruce Area Aggregate Capacity Factor Assumptions to Perceived Need for Proposed Line

As the graphs in the previous section show, using less than a 100% capacity factor for Bruce area aggregate generation highlights the sensitivity of that assumption to the need for more transmission capacity away from the Bruce area.

Using reasonable assumptions for operational conditions on the aggregate output of Bruce nuclear and Bruce wind resources at any given time, the amount of transmission available without the proposed line is adequate to deliver output of eight nuclear units (6,400 MW MCR) and 1,700 MW (rated capacity) of wind with likely little undelivered energy.

The table below illustrates the sensitivity of the capacity factors of the Bruce area generation to the ability of the transmission system to deliver the area's output.

Table 1. Illustration of Effect of Aggregate Capacity Factor on Total Generation and Comparison to Transmission Capability

	Bruce Nuclear	Wind	Total
Nominal MCR - MW - Post 2015, excluding Bruce "B" Refurb Periods	6,400	1,700	8,100
HONI Planning Capacity Factor	100%	100%	100%

Sensitivity of Aggregate Generation to Capacity Factor Assumptions

Aggregate Capacity Factor	Nuclear	Wind
Low	65%	20%
Medium	80%	40%
High	95%	60%

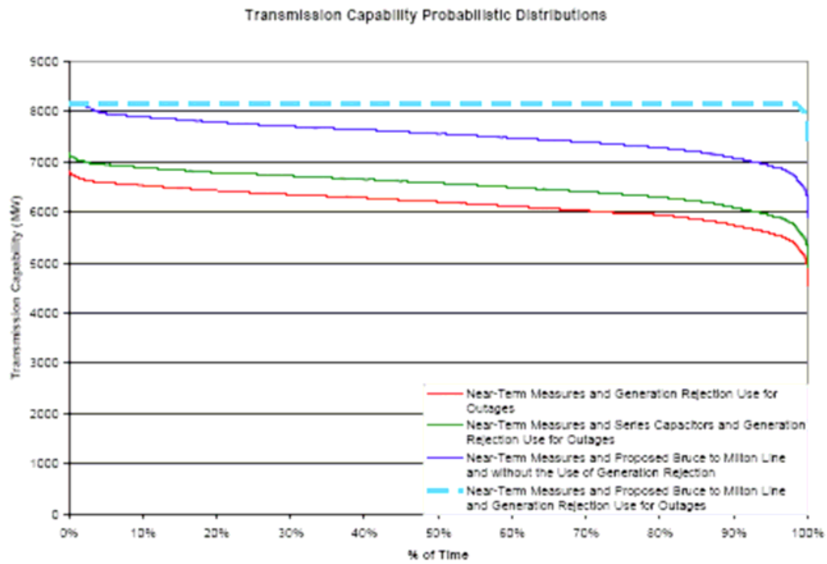
Aggregate Generation Output, MW	Nuclear	Wind	Total
Low	4,160	340	4,500
Medium	5,120	680	5,800
High	6,080	1,020	7,100

Transmission Capability, MW	
Transfer Limit Proposed Line:	8,100
Transfer Limit "Interim" [NTM + SC + BSPS]	7,076
Transfer Limit "Interim" with 600 MW Derate	6,476

In response to Pollution Probe interrogatory No. 47, HONI described the modeling they used to estimate the undelivered energy arising from Bruce area. In that response, HONI presented a probability distribution for the transmission resource in the area (see Figure 6 below) and a probability distribution for transmission system "derating" (Figure 7). In Figure 6, it can be seen that the midpoint of the curve for the series compensation option (using generation rejection) is observed to be approximately 6,600 MW, indicating that HONI believes that half the time, transfer capability will be above this level and half the time it will be below this level, and will always be bounded by the upper limit of 7,076 MW and a lower limit of approximately 5,000 MW.

Figure 6. HONI's Depiction of the Distribution of Transfer Capability Out of Bruce Area

Figure 4



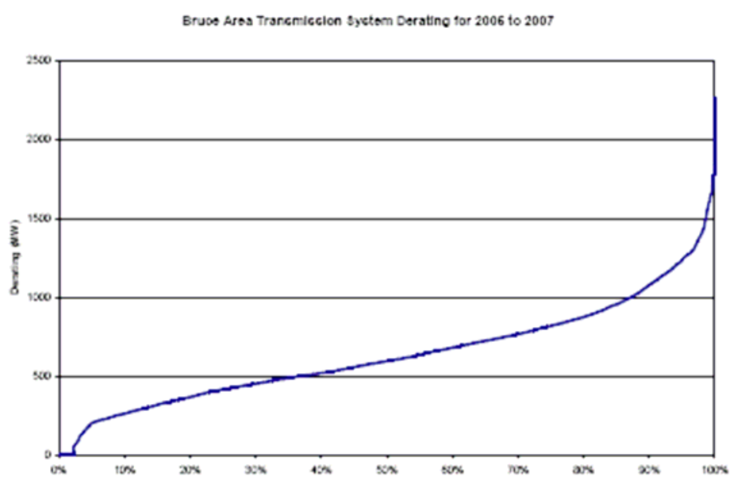
Source: Response to Pollution Probe IR # 47. HONI Exhibit C, Tab 2, Schedule 47, Page 6.

Figure 7. HONI Depiction of the Distribution of "Derating" of the Transfer Capability out of Bruce Area

Table 3 – Normal System Transmission Limits @ NBLIP = 500 MW

Normal System Transmission Limits (MW)	Near-Term Measures	Near-Term Measures + GR (Short-Term Use)	Near-Term Measures + SCAP	New BxM Line
Elements Out-of-Service (use GR)	6821	6821	7176	8160
All Elements In-Service	5976	6821	6776	8160

Figure 1 – Bruce Area Transmission System Derating Data



Source: Response to Pollution Probe IR # 47. HONI Exhibit C, Tab 2, Schedule 47, Attachment A Page 3.

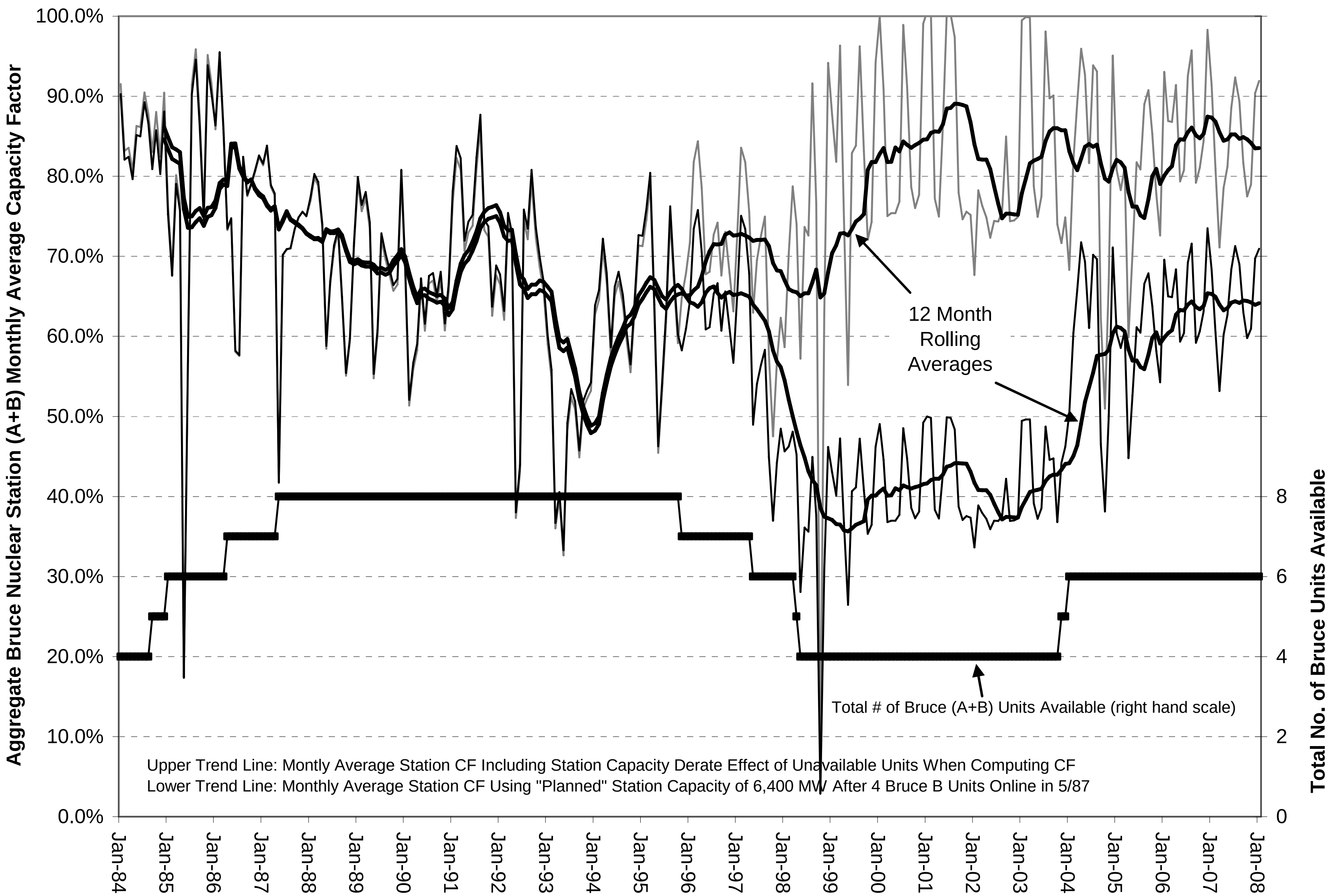
Bruce Nuclear Station Monthly Average Capacity Factors, 1984-2008

Historical capacity factor information for the Bruce nuclear station supports use of capacity factor averages that are certainly lower than 100% of aggregate MCR for the Bruce nuclear station, when assessing transmission need to deliver Bruce area energy.

In response to Pollution Probe interrogatory #1, HONI provided the 24-year history of the output of Bruce nuclear station A and B, from 1984 through January of 2008. As illustrated in Figure 8 below, it is rare that total output *of the entire station* exceeded average capacity factors of 80%. We have used values of 95% to demonstrate the sufficiency of the transmission system without the proposed line (see Figure 3).

For the purpose of evaluating the ability of a reinforced transmission system – one that excludes the proposed new line – to carry Bruce area output, what is most important is aggregate output: the coincident, combined total of all generation in the region, nuclear and wind, accounting for output variation. Individual unit operation is less important. As this graph clearly shows, even during the times when eight units were available for operation at Bruce (1987 through 1995), the station total average monthly capacity factor was often in the sixty to eighty percent range, hitting peak values in the mid-to-high eighties just for a few months, and bottoming out in the thirties and forties for a number of months.

Figure 8. 24-Year History of Bruce Nuclear Station (A+B) Actual Monthly Average Capacity Factor, 1984 - 2008



Use of Installed Wind Capacity Exaggerates Effect of Aggregate Wind Resource on Transmission Needs

Wind plant output assumptions indicate that use of 100% MCR exaggerates the likely aggregate availability of wind resource capacity in the Bruce area.

In response to Pollution Probe interrogatory # 24 and 25, HONI provided information on the average seasonal wind resource capacity factor for existing, committed and new wind resources. Those are shown in the table below.

Table 2. Seasonal Average Capacity Factor for Existing, Committed and New Wind Resources

Existing and Committed Wind

MW	Season	Period	MWh	Ave CF
700	Winter	Peak	144,345	33.90%
700	Winter	Mid-Peak	164,411	33.78%
700	Winter	Off-Peak	382,825	33.83%
700	Summer	Peak	76,556	20.97%
700	Summer	Mid-Peak	113,177	20.67%
700	Summer	Off-Peak	229,709	20.30%
700	Shoulder	Mid-Peak	294,586	32.28%
700	Shoulder	Off-Peak	353,057	31.20%
			1,758,666	28.68%

1000 MW New Wind

MW	Season	Period	MWh	Ave CF
1000	Winter	Peak	206,207	33.90%
1000	Winter	Mid-Peak	234,873	33.78%
1000	Winter	Off-Peak	546,892	33.83%
1000	Summer	Peak	109,366	20.97%
1000	Summer	Mid-Peak	161,681	20.67%
1000	Summer	Off-Peak	328,156	20.30%
1000	Shoulder	Mid-Peak	420,837	32.28%
1000	Shoulder	Off-Peak	504,367	31.20%
			2,512,379	28.68%

Source: Response to Pollution Probe IR Nos. 24 and 25.

The table illustrates a maximum seasonal and period average of 34% during winter peak times.

Peak wind output generally occurs during winter periods. While there will be periods during which aggregate area wind output will exceed the 34% average, a more careful examination of the Bruce area wind output variation during these high wind periods is required. Depending on the output of the Bruce nuclear station during these periods – which is when the potential for the highest aggregate coincident Bruce area generation occurs – there could be a need to curtail some generation that otherwise might be available.

HONI Estimates of Locked-In Energy

"Locked-in energy" (the same as "undelivered energy) in the Bruce area is any energy capable of being generated at either the Bruce nuclear power station or at wind turbine generation stations that connect to the Bruce area transmission system, but is unable to be transmitted because of limitations on the ability of the transmission system to reliably operate in certain hours if it accepted all such energy.

HONI has estimated the annual amount and the annual value of the locked-in energy in the Bruce region in response to interrogatory number 7 of Pollution Probe. As noted in a subsequent section, the comprehensive assumptions used by HONI to estimate locked-in energy are not readily transparent. Tables 3 and 4 show HONI's estimate of the quantity and value of locked-in energy.

Table 3. HONI Estimate of Locked-In Energy, MWh

	Scenario				
Year	A	B	C	D	E
2012	59,545	59,545	6,497	6,497	2,953
2013	1,489,431	1,489,431	608,816	608,816	255,128
2014	2,271,113	2,271,113	1,115,368	1,115,368	495,319
2015	2,573,342	2,573,342	1,340,332	1,340,332	614,178
2016	2,573,342	2,573,342	1,340,332	1,340,332	614,178
2017	2,573,342	2,573,342	1,340,332	1,340,332	614,178
2018	494,611	494,611	175,495	1,340,332	614,178
2019	29,499	29,499	4,680	1,340,332	614,178
2020	29,499	29,499	4,680	102,658	48,451
2021	29,499	29,499	4,680	3,220	1,610
2022	29,499	29,499	4,680	-	-
2023	494,611	494,611	175,495	-	-
2024	2,573,342	2,573,342	1,340,332	-	-
2025	2,573,342	2,573,342	1,340,332	-	-
2026	2,573,342	2,573,342	1,340,332	-	-
2027	2,573,342	2,573,342	1,340,332	-	-
2028	2,573,342	2,573,342	1,340,332	-	-
2029	2,573,342	2,573,342	1,340,332	-	-
2030	2,573,342	2,573,342	1,340,332	-	-
Total 2012 - 2030	30,660,727	30,660,727	15,503,711	8,538,219	3,874,351

Scenario Legend:

A	Including Near Term Measures (NTM)
B	NTM + Expansion of Bruce Special Protection System (BSPS)
C	NTM + BSPS + Series Capacitor Installation (SC)
D	NTM + BSPS + SC + No Refurbisment of Bruce B and No New Nuclear Units
E	Scenario D + Bruce Nuclear Station Ave. CF is 10% lower than OPA estimate

Source: HONI, Exhibit C Tab 2 Schedule 7 Page 3.
In response to Pollution Probe IR #7.

Table 4. HONI Estimate of Value of Locked-In Energy, $2007 Net Present Value

	Locked In Energy Value NPV $2007 Millions				
Year	A	B	C	D	E
2012	3	3	0	0	0
2013	69	69	29	29	12
2014	105	105	52	52	23
2015	120	120	63	63	29
2016	115	115	60	60	28
2017	110	110	58	58	26
2018	20	20	7	55	25
2019	1	1	0	53	24
2020	1	1	0	4	2
2021	1	1	0	0	0
2022	1	1	0	0	0
2023	17	17	6	0	0
2024	82	82	43	0	0
2025	78	78	41	0	0
2026	75	75	39	0	0
2027	72	72	38	0	0
2028	69	69	36	0	0
2029	67	67	35	0	0
2030	64	64	34	0	0
Total 2012 - 2030	1,070	1,070	541	374	169

Source: HONI, Exhibit C Tab 2 Schedule 9 Page 3.
In response to Pollution Probe IR #9.

Based on the values in the table above, combined with HONI's estimates of line loss reduction benefits (equal to $301 million NPV in $2012)[2] it can be seen that under Scenario E, the proposed line's benefits do not outweigh its costs. For Scenario D, the benefits do outweigh the costs. The difference between Scenarios D and E are the assumptions made about the aggregate capacity factor for Bruce nuclear station. This illustrates that based on HONI's own assessment, the assumptions one makes about Bruce nuclear station aggregate capacity factor changes the results of the cost-benefit analysis and results in either a positive or a negative net benefit. This illustrates the importance of using very transparent methods in the computation of locked-in energy when examining the overall economics of the proposed line.

HONI Estimates of Locked-In Energy Are Not Transparent

In response to Pollution Probe interrogatory no. 47, HONI provided information on the manner in which they computed locked-in energy.

However, the information provided does not allow one to know the exact assumptions made for transmission capacity or aggregate Bruce area generation for any given period (monthly periods are the finest level of temporal granularity reported by HONI). It is not possible to replicate HONI's results independently, and then test the sensitivity of the results using different

[2] Exhibit C, Tab 6, Schedule 14, Page 3 indicates that net present value of line loss benefits in $2012 are $301 million for the period 2012-2030. This value is with Bruce B refurbished. Line loss benefits of the proposed line will be significantly less in the years after the tentative refurbishment period if "B" is not refurbished, and total benefits should take this into account, especially since refurbishment is not yet approved.

assumptions. Given the critical importance of locked-in energy estimates to the determination of whether or not the proposed line results in net benefits or net costs, HONI must provide the following information in order to test their assumptions:

- For each monthly period for which locked-in energy has been estimated, what aggregate capacity factor is used for Bruce nuclear station (i.e., what is the total amount of net generation capacity assumed available at the station for each month);
- For each monthly period for which locked-in energy has been estimated, what aggregate capacity factor is used for wind resource output;
- What average transmission capability is assumed for each month.

Near Term and Interim Measures are Less Costly per MW Than Proposed Line

The proposed line costs and resulting incremental transmission transfer increase suggest considerable diminishing returns relative to the near-term and intermediate term transmission reinforcement measures.

The ability of transmission system improvements to increase the transfer capability away from the Bruce region was summarized by HONI in response to Pollution Probe's interrogatory # 16. HONI filed Exhibit C, Tab 2, Schedule 16, page 2. A summary of the key points in HONI's table is given below.

Table 5. Transmission Transfer Increase and Associated Costs: HONI Scenarios for Improving Capacity Away from Bruce

		Cost of Measure(s)	
Scenario	MW Increase	$ Millions	$/kW of Increase
NTM	385	216	561
NTM + BSPS	941	7	7
NTM + BSPS + SC	750	97	129
Total Near Term and Intermediate	2,076	320	**154**
Proposed Bruce to Milton Circuits	1,084	645	**595**
Proposed Circuits vs. Total NT and Intermediate Measures Ratio of costs per KW of increase			**3.86**

Legend

NTM	Near Term Measures
BSPS	Bruce Special Protection System
SC	Series Compensation

Source: Exhibit C Tab 2 Schedule 16 Page 2
In response to Pollution Probe interrogatory #16.

Near term and intermediate transmission system improvements including series compensation and use of generation rejection special protection systems increase the transfer capability limit “away from Bruce” by 2,076 MW, at a cost of approximately $154 per kW of increased capacity limit.

The proposed line would further increase the limit by 1,084 MW, at a cost of approximately $595 per kW of increased capacity limit.

Thus the line would serve to increase the capability of the transmission system by increasing the “flow away from Bruce” limit by approximately 1,084 MW over and above the 7,076 MW level achievable with near-term and intermediate steps. This increment of capacity comes at a cost that is 3.86 times as great per MW as the cost of the near-term and medium term improvements, clearly illustrating the diminishing returns of the proposed line relative to near term and intermediate improvements.

Section IV: Assessment of Use of Near Term and Interim Measures Including Series Compensation and Generation Rejection Schemes

Use of Series Compensation is Reasonable and Prudent as a Means to Increase the Capacity of Existing Transmission Lines

Transmission capacity can be increased without the need to build new transmission lines. As we note in our report, the use of series capacitors, or series compensation as it is also referred to, can help maintain voltage under contingency conditions and can help control power flows over the transmission system. It is a proven technology that has been reliably used in hundreds of applications. As described in the OPA's due diligence study on the use of 500 kV series capacitors in southwestern Ontario:

> Uncompensated transmission assets are normally under utilized, particularly if their length is such that their power transfer capacity is impedance and stability limited (through voltage collapse or angular instability) rather than thermally limited. Applying series compensation with series capacitors (SCAP) is an accepted method of increasing the transfer capacity of a high voltage transmission line that is impedance limited. The transmission impedance is reduced allowing more power to be transferred along the line.[3]

Hydro One's perspective on the prospective use of series capacitors appears to reflect a lack of familiarity with the particular technology, rather than reflect specific instances of problems with series compensation:

> Hydro One is cognizant of the fact that series compensation is a proven transmission technology outside Ontario. However, Hydro One's past experience is that newly installed products or technologies are prone to suffering unexpected malfunctions or mis-operations during their initial deployment due to unexpected design or manufacturing deficiencies. Such "teething pains" have resulted in prolonged equipment unavailability and/or adverse system impacts. These outcomes, coupled with the substantial reliability and commercial consequences of the series compensation performing poorly, unique power system characteristics, protection implications, and concerns about system operability, necessitate the need for due diligence considerations for this option, in the context of its utilization in Southwestern Ontario, as indicated in the Transmission Document. (Exh. C/T 2/S 46/p 6)

While it is difficult to appreciate the logic of rejecting a technology because of problems with other newly installed products or technologies, it is worth noting that the Company recognizes that series compensation is a proven transmission technology, as well as the need for due diligence in its utilization.

[3] Exh C/T 4/S 6/Attachment 1/p 7

The OPA's due diligence report of the use of series compensation (Exh C/T 4/S 6/Attachment 1/p 2-3) addresses more traditional concerns about the subject:

> Although series capacitors applied to high voltage transmission systems is a mature technology with hundreds of successful installations in service in North America and around the world, the resulting impact they may have on the ac system is complex and severe. The main issues are:
>
> 1. **System Reliabilit**y. Generally, adding series capacitors to existing transmission lines without adding additional circuits to accommodate increased power flow causes parallel circuits to be more highly loaded under contingency conditions. This results in a higher average line and transformer loading which can be thought of as an ever growing stress on the network. This wide spread stress exacerbates the impacts of routine contingencies and the latent failures and grid imperfections that compound them.
>
> Generally, adding series capacitors instead of additional circuits tend to speed the transition from one worse case contingency event and one worst case limiting element to multiple worst case events and multiple limiting elements, making grid failures from severe contingency events more likely. The series compensated and, seemingly robust network carrying ever more power is not only less reliable for the above reasons, but opens the door to impacts of contingencies and cascading over larger areas. Careful design of the Bruce special protection system (BSPS) can counteract reduced system reliability when adding series capacitors for these increased power flows but is a complex adjustment to do successfully. In addition, careful design applied to each series capacitor bank can minimize the impact of failure modes within the bank and its consequential negative influence on system reliability.
>
> 2. **Sub-synchronous resonance (SSR)**. SSR is one of the most significant aspects that require attention. Although the undesired overlap of generator shaft torsional modes with the complementary electrical resonance is less likely the lower the level of series compensation applied, there is no guarantee that sub-synchronous resonance can be avoided altogether. With the 30% level of series compensation considered for application in Southwestern Ontario (SWO), it appears the Nanticoke generators under transmission contingency conditions will be more susceptible to sub-synchronous resonance than the units at Bruce under contingency conditions. For the period of time that the Nanticoke generators will be in operation after the series capacitors are installed, a strategy to mitigate SSR will need to be put in place, that might consist of operating restrictions, shaft torsional damping through the unit exciters, and application of torsional stress relays. When these generators are decommissioned and four units possibly retained as decoupled synchronous compensators, it is expected that as decoupled units, these torsional modes of shaft resonance will no longer exist except the generator and exciter mode should be checked. Attention will need to be paid to the Lambton units, but the impact of SSR on them appears less than at Nanticoke.
>
> The Bruce generators would not have their complementary torsional frequencies within range of resonant frequencies created by 30% series compensation, based on critical contingencies. Nevertheless a detailed design study for the proposed series capacitor installations should be considered to ensure adequate damping of any sub-synchronous resonances with generators is achieved. However, it would not need to be undertaken with the comprehensiveness of the ABB study [1], but concentrate on the Bruce units with 30% series compensation on B562L, B563L and N582L transmission lines. At this stage no SSR mitigation design is recommended for the series capacitor banks but operating restrictions be defined and put in

place, and possibly tuning the unit's exciters to increase torsional damping. Finally, it is recommended that consideration be given to adding torsional stress relays to all Bruce and Lambton units, as well as to any Nanticoke units retained as generators after the installation of the series capacitors. This is not an insignificant cost, and would amount to several millions of dollars.

3. **Reactive Power.** The reactive power requirements of the SWO system with the increased loading on the series compensated transmission lines, particularly under contingency conditions will require significant additional reactive power support that needs to be quantified and characterized as to whether it is installed with fixed, switched or dynamic compensation and where it is to be installed.

4. **Engineering Complexity.** In spite of the precautionary measures that must be undertaken, series capacitors are an appropriate engineering facility that can be added to major transmission lines in the SWO network to increase power transfer capability. The technical issues that must be addressed such as those outlined above and in this report can be addressed with judicious due diligence and well established and accepted engineering practice. (underline added)

While there are system planning concerns about the use of series capacitors, loading system elements up to their design capacities should not be one of them. This is the same report that describes uncompensated transmission lines as being underutilized, as noted above. The whole point in using series capacitors is to allow existing transmission lines to use as much of their design capacity as possible. Otherwise, you end up building transmission lines that are not really needed. And, as noted in the above, series capacitors are a mature technology with hundreds of successful installations worldwide.

In spite of all the negative comments about series compensation, OPA's due diligence study reaches the conclusion, as noted above, that series capacitors are appropriate for use on the major transmission lines in southwestern Ontario to increase power transfer capability. There is no apparent support for the Company's position that long term use of series capacitors is not consistent with NPCC reliability standards. Without such use, transmission lines in the Province will continue to be underutilized.

Use of Generation Rejection is Reasonable to Protect Against Events that Occur Infrequently.

The use of generation rejection for up to two Bruce units in an effort to increase transfer capability is a reasonable practice to deal with short-term needs that will be eliminated as the Bruce B units retire. Generation rejection, and load rejection, in response to system contingencies, is a long established operating practice in the Province, especially where the Bruce nuclear generating units are concerned. Historically, up to four of the eight Bruce units have been subject to generator rejection. As addressed in the IESO's 10-Year Outlook in Exh. C/T 4/S 1/Attachment 1:

> The generation was installed over the mid 70's to mid 80's. Four units were removed from service in 1998, at the same time as four Pickering units. Of these four Bruce units, two units have since been returned to service in 2003. Two units (1 and 2) remain out of service.

> The transmission additions constructed to incorporate the station into the Ontario network were not as desired by Ontario Hydro. The preferred implementation included a double circuit 500 kV line from Bruce to Essa in the Barrie area. Public opposition to these circuits ultimately prevented this construction. The Bruce to Longwood 500kV circuits were installed as a somewhat less capable alternative. As a result of this change, the full output of the Bruce complex could not be accommodated by the transmission system. In order to increase the capability of the transmission system to the level required, an automated “Special Protection Scheme” (SPS) was installed. In taking this step, the reliability of both the Bruce generation and many customers in Ontario was reduced to achieve increased economic benefits of the Bruce complex. In essence, the SPS allows for detection of certain power system events and immediately disconnects generators at Bruce and a large amount of customer load throughout southern Ontario to prevent a system disturbance such as that experienced in August 2003.
>
> Without the SPS, Bruce output is limited to approximately 5,000 MW (capacity equivalent to approximately six Bruce units). With the SPS, Bruce output with eight units in operation (6,500 MW) could be accommodated provided up to four units (3,200 MW) were ‘rejected’ or disconnected instantaneously together with 1,500 MW of customer load (approximately half the load in downtown Toronto). These extensive and complex automatic actions, representing by far the largest use of an SPS by an interconnected system operator, were considered a temporary measure until additional transmission could be constructed. Ontario’s neighbouring system operators insisted on stringent conditions with respect to the design and use of the SPS in order to protect their own systems from a cascading disturbance. The majority of the SPS has not been used in over a decade following the shutdown of four Bruce units in 1998.

The use of generation rejection of up to two Bruce units is well within the expectations that the IESO expressed in its ten year outlook, dated August 15, 2005:

> There is a high degree of uncertainty with respect to our neighbours’ agreement with such a scheme’s future use. <u>The IESO believes it is prudent to enhance the transmission system so that generation rejection is limited to 2 Bruce units, and the load rejection portion of the special protection scheme is not required to be used in conjunction with generation rejection to maintain Bruce stability.</u> The load rejection portion of the scheme should be maintained only to overcome difficulties in the operating time frame that would otherwise require pre-contingency load shedding. From the late 1990’s this was not a major concern as there were no firm plans to rehabilitate units at Bruce. When this became desirable, the studies performed by the IESO, Hydro One and Bruce Power have identified the need for transmission expansion to accommodate additional generation at Bruce. <u>This may take the form of series compensation of existing transmission lines or the additional of new transmission lines.</u> Exh C/T 4/S 1/Attach 1/p 46-47

It is interesting to note that, less than three years ago, the IESO considered use of generator rejection to reject up to two Bruce units to be prudent. Also, it is important to note that the IESO declared that series compensation is an acceptable alternative to a new transmission line.

As for the feeling that there is uncertainty as to HONI's neighbors acceptance of a generation rejection scheme's future use, there are a number of relevant considerations. First, this use is to address what is, at most, a temporary shortage of transfer capability. As demonstrated in Figures 2, 3, and 4 above, the need for firm transmission capacity at Bruce will decline starting in 2017, so the need to use generator rejection on a first contingency would also decline.

Second, the reliability group that will consider HONI's use of generator rejection, the NPCC, has **never** rejected a request to use generation rejection for Bruce.[4] The NPCC uses an especially stringent definition of what constitutes a first contingency,[5] but has historically allowed the use of generator rejection to address such contingencies.

Third, there has been no shortage of generator rejection use at Bruce. Over the past three years, generator rejection for at least one Bruce unit has been in use for 4,300 to 5,500 hours per year, and generator rejection for two Bruce units has been in use for about 1,100 hours per year.[6]

Fourth, the contingencies that have actually triggered generation rejection are extremely rare. For Bruce, this contingency, the loss of the Bruce-Milton-Claireville 500 kV transmission line, last occurred in 1985, and it caused the rejection of three Bruce units.[7]

New Circuit Forgoes Use Of Generator Rejection For First Contingency

If we want to forgo generator rejection for a "first" contingency that takes out the existing double circuit 500 kV transmission line that runs between Bruce and Milton, there is a single circuit 500 kV alternative to the Company's proposal.

At our request, the IESO ran base case and contingency case load flow studies with a new single circuit 500 kV transmission line between Longwood and Middleport and with series compensation. The results of these studies are included in the appendices as Diagrams 3 (base case) and 4 (contingency on existing Bruce 500 kV double circuit running towards Milton).

With this new single circuit 500 kV line, which would be about 145 km in length, all eight Bruce units and 675 MW of committed wind can be transmitted, even under contingency conditions, with no generator rejection for the "first" contingency. This is less than the 8,100 MVA of transfer capability provided by the Company's proposal, but, as discussed earlier in this document, it is not clear when a real need for as much as 8,100 MVA of transmission capacity will actually materialize.

In light of the uncertain long term need for transmission capacity out of Bruce, use of generator rejection and series compensation are definitely preferable to undertaking a permanent

[4] Exh C/T 2/S 46/(e) ii
[5] The power system should be stable and be able to carry system loads following the loss of any of the double-circuit transmission lines, which under NPCC rules, is considered a first contingency. (Exh. B/T 1/S 1/p 4)
[6] Exh C/T 2/S 46/(e) iii
[7] Exh C/T 2/S 46/(e) iii

commitment in the form of building of a new transmission line. However, if a new line is not avoidable, then a new single circuit 500 kV line from Longwood to Middleport has several benefits compared to the proposed new Bruce – Milton line:

> It is shorter, at 145 km, than the Company's proposed 500 kV double circuit transmission line, which is 176 km. A shorter new transmission has fewer impacts and potentially lower costs than a longer new line.
>
> It avoids putting two 500 kV circuits on one towerline, thereby avoiding losing two 500 kV circuits to a "single" contingency. The Company's proposed new line puts two 500 kV circuits on one tower line, which, with one contingency, could leave the system right back where it is today.
>
> It avoids an over concentration of 500 kV circuits in one right-of-way, thereby eliminating the chance of a common mode failure taking out four 500 kV circuits on one right-of-way, as is possible with the Company's proposal.

There is some apparent disagreement over how much a new single circuit line from Longwood to Middleport would really cost. The Company produced cost estimates, but, in these estimates, much more than just a single circuit 500 kV line is included in the costs.[8] The Company's cost estimate includes construction of a triple circuit transmission line from Longwood to Buchanan with one 500 kV circuit and two 230 kV circuits and the removal of an existing 230 kV two circuit line between these two stations. The Company's cost estimate also includes construction of a double circuit transmission line from Buchanan to Middleport with one 500 kV circuit and one 230 kV circuit and the removal of an existing 230 kV single circuit line between these two substations. With all these additional facilities included, the cost estimate provided by the Company reflects a lot more than just building a single circuit 500 kV line from Longwood to Middleport. Even with all these extra costs, the cost of Longwood to Middleport 500 kV circuit is estimated at $435 million for 145 km of transmission line costs and $95 million for station work,[9] [10] compared to $555 million for the 176 km of the Company's proposed line, and $80 million for station work and other costs.[11] The Longwood to Middleport alternative would also include an estimated $129 million[12] for series compensation. This would bring total costs for the Longwood to Middleport alternative to $659 million, compared to $635 million for the Company's proposal.

However, the above cost for the Longwood to Middleport alternative includes the cost of building double circuit and triple circuit transmission lines, where only a single circuit line is being added. Assuming that a double or triple circuit line can be built for something in the range of 1.66 to 1.75 times the cost for a single circuit line, this means that the $435 million in transmission line costs referenced above includes some $173 million to $186 million of

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[8] Exh C/T 2/S 43/(b)(i)/ p 3-4
[9] Exh C/T 2/S 43/(b)(i)/ p 3-4
[10] We note that the $95 million in station work includes some %50 million for additional modifications at Middleport TS to create a breaker and a half scheme for the existing circuits.
[11] Exh B/T 4/S 2/p 1
[12] $97 million for series compensation on three lines (see Exh C/T 2/S 16/) increased by one-third to reflect additional series compensation for the new Longwood to Middleport line.

additional expense for additional circuits. Removing this additional expense would reduce the total cost of the Longwood to Middleport alternative to something in the range $473 million to $486 million[13] for single circuit construction, which would reflect savings of from $149 million to $162 million compared to the $635 million cost estimated for the Company's proposal.

[13] $435 million divided by 1.66 equals $262 million of estimated single circuit cost and $173 million of savings from the Company's estimate. $435 million divided by 1.75 equals $249 million of estimated single circuit costs and $186 million of savings from the Company's estimate.

Appendix 1: Qualification Information for Peter J. Lanzalotta

Mr. Lanzalotta has more than twenty-five years experience in electric utility system planning, power pool operations, distribution operations, electric service reliability, load and price forecasting, and market analysis and development. Mr. Lanzalotta has appeared as an expert witness on utility reliability, planning, operation, and rate matters in more than 80 proceedings in 21 states, the District of Columbia, the Provinces of Alberta and Ontario, and before the Federal Energy Regulatory Commission. He has developed evaluations of electric utility system cost, value, reliability, and condition. He has participated in negotiations between utilities and customers or regulators in more than ten states regarding transmission access, the need for facilities, electric rates, electric service reliability, the value of electric system components, and system operator structure under wholesale competition.

Prior to his forming Lanzalotta & Associates LLC in 2001, he was a Partner at Whitfield Russell Associates for fifteen years and a Senior Associate for approximately four years before that. He holds a Bachelor of Science in Electric Power Engineering from Rensselaer Polytechnic Institute and a Master of Business Administration with a concentration in Finance from Loyola College of Baltimore.

Prior to joining Whitfield Russell Associates in 1982, Mr. Lanzalotta was employed by the Connecticut Municipal Electric Energy Cooperative ("CMEEC") as a System Engineer. He was responsible for providing operational, financial, and rate expertise to Coop’s budgeting, ratemaking and system planning processes. He participated on behalf of CMEEC in the Hydro Quebec/New England Power Pool Interconnection project and initiated the development of a database to support CMEEC's pool billing and financial data needs.

Prior to his CMEEC employment, he served as Chief Engineer at the South Norwalk (Connecticut) Electric Works, with responsibility for planning, data processing, engineering, rates and tariffs, generation and bulk power sales, and distribution operations. While at South Norwalk, he conceived and implemented, through Northeast Utilities and NEPOOL, a peak-shaving plan for South Norwalk and a neighboring municipal electric utility, which resulted in substantial power supply savings. He programmed and implemented a computer system to perform customer billing and maintain accounts receivable accounting. He also helped manage a generating station overhaul and the undergrounding of the distribution system in South Norwalk’s downtown.

From 1977 to 1979, Mr. Lanzalotta worked as a public utility consultant for Van Scoyoc & Wiskup and separately for Whitman Requart & Associates in a variety of positions. During this time, he developed cost of service, rate base evaluation, and rate design impact data to support direct testimony and exhibits in a variety of utility proceedings, including utility price squeeze cases, gas pipeline rates, and wholesale electric rate cases.

Prior to that, He worked for approximately 2 years as a Service Tariffs Analyst for the Finance Division of the Baltimore Gas & Electric Company where he developed cost and revenue studies, evaluated alternative rate structures, and studied the rate structures of other utilities for a variety of applications. He was also employed by BG&E in Electric System Operations for approximately 3 years, where his duties included operations analysis, outage reporting, and participation in the development of BG&E's first computerized customer information and service order system.

Mr. Lanzalotta is a member of the Institute of Electrical & Electronic Engineers, the National Society of Professional Engineers, the Association of Energy Engineers, the National Fire Protection Association, the American Solar Energy Society, and the Financial Management Association. He is also registered Professional Engineer in the states of Maryland and Connecticut.

Appendix 2: Proceedings in which Mr. Lanzalotta Has Testified

1. **In re: Public Service Company of New Mexico**, Docket Nos. ER78-337 and ER78-338 before the Federal Energy Regulatory Commission, concerning the need for access to calculation methodology underlying filing.

2. **In re: Baltimore Gas and Electric Company**, Case No. 7238-V before the Maryland Public Service Commission, concerning outage replacement power costs.

3. **In re: Houston Lighting & Power Company**, Texas Public Utilities Commission Docket No. 4712, concerning modeling methods to determine rates to be paid to cogenerators and small power producers.

4. **In re: Nevada Power Company**, Nevada Public Service Commission, Docket No. 83-707 concerning rate case fuel inventories, rate base items, and O&M expense.

5. **In re: Virginia Electric & Power Company**, Virginia State Corporation Commission, Case No. PUE820091, concerning the operating and reliability-based need for additional transmission facilities.

6. **In re: Public Service Electric & Gas Company**, New Jersey Board of Public Utilities, Docket No. 831-25, concerning outage replacement power costs.

7. **In re: Philadelphia Electric Company**, Pennsylvania Public Utilities Commission, Docket No. P-830453, concerning outage replacement power costs.

8. **In re: Cincinnati Gas & Electric Company**, Public Utilities Commission of Ohio, Case No. 83-33-EL-EFC, concerning the results of an operations/fuel-use audit conducted by Mr. Lanzalotta.

9. **In re: Kansas City Power and Light Company**, before the State Corporation Commission of the state of Kansas, Docket Nos. 142,099-U and 120,924-U, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

10. **In re: Philadelphia Electric Company**, Pennsylvania Public Utilities Commission, Docket No. R-850152, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

11. **In re: ABC Method Proposed for Application to Public Service Company of Colorado**, before the Public Utilities Commission of the State of Colorado, on behalf of the Federal Executive Agencies ("FEA"), concerning a production cost allocation methodology proposed for use in Colorado.

12. **In re: Duquesne Light Company**, Docket No. R-870651, before the Pennsylvania Public Utilities Commission, on behalf of the Office of Consumer Advocate, concerning the system reserve margin needed for reliable service.

13. **In re: Pennsylvania Power Company**, Docket No. I-7970318 before the Pennsylvania Public Utilities Commission, on behalf of the Office of Consumer Advocate, concerning outage replacement power costs.

14. **In re: Commonwealth Edison Company**, Docket No. 87-0427 before the Illinois Commerce Commission, on behalf of the Citizen's Utility Board of Illinois, concerning the determination of the capacity, from new base-load generating facilities, needed for reliable system operation.

15. **In re: Central Illinois Public Service Company**, Docket No. 88-0031 before the Illinois Commerce Commission, on behalf of the Citizen's Utility Board of Illinois, concerning the degree to which existing generating capacity is needed for reliable and/or economic system operation.

16. **In re: Illinois Power Company**, Docket No. 87-0695 before the State of Illinois Commerce Commission, on behalf of Citizens Utility Board of Illinois, Governors Office of Consumer Services, Office of Public Counsel and Small Business Utility Advocate, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

17. **In re: Florida Power Corporation**, Docket No. 860001-EI-G (Phase II), before the Florida Public Service Commission, on behalf of the Federal Executive Agencies of the United States, concerning an investigation into fuel supply relationships of Florida Power Corporation.

18. **In re: Potomac Electric Power Company**, before the Public Service Commission of the District of Columbia, Docket No. 877, on behalf of the Public Service Commission Staff, concerning the need for and availability of new generating facilities.

19. **In re: South Carolina Electric & Gas Company,** before the South Carolina Public Service Commission, Docket No. 88-681-E, On Behalf of the State of Carolina Department of Consumer Affairs, concerning the capacity needed for reliable system operation, the capacity available from existing generating units, relative jurisdictional rate of return, reconnection charges, and the provision of supplementary, backup, and maintenance services for QFs.

20. **In re: Commonwealth Edison Company**, Illinois Commerce Commission, Docket Nos. 87-0169, 87-0427, 88-0189, 88-0219, and 88-0253, on behalf of the Citizen's Utility Board of Illinois, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation.

21. **In re: Illinois Power Company**, Illinois Commerce Commission, Docket No. 89-0276, on behalf of the Citizen's Utility Board Of Illinois, concerning the determination of capacity available from existing generating units.

22. **In re: Jersey Central Power & Light Company**, New Jersey Board of Public Utilities, Docket No. EE88-121293, on behalf of the State of New Jersey Department of the Public Advocate, concerning evaluation of transmission planning.

23. **In re: Canal Electric Company**, before the Federal Energy Regulatory Commission, Docket No. ER90-245-000, on behalf of the Municipal Light Department of the Town of Belmont, Massachusetts, concerning the reasonableness of Seabrook Unit No. 1 Operating and Maintenance expense.

24. **In re: New Hampshire Electric Cooperative Rate Plan Proposal**, before the New Hampshire Public Utilities Commission, Docket No. DR90-078, on behalf of the New Hampshire Electric Cooperative, concerning contract valuation.

25. **In re: Connecticut Light & Power Company**, before the Connecticut Department of Public Utility Control, Docket No. 90-04-14, on behalf of a group of Qualifying Facilities concerning O&M expenses payable by the QFs.

26. **In re: Duke Power Company**, before the South Carolina Public Service Commission, Docket No. 91-216-E, on behalf of the State of South Carolina Department of Consumer Advocate, concerning System Planning, Rate Design and Nuclear Decommissioning Fund issues.

27. **In re: Jersey Central Power & Light Company**, before the Federal Energy Regulatory Commission, Docket No. ER91-480-000, on behalf of the Boroughs of Butler, Madison, Lavallette, Pemberton and Seaside Heights, concerning the appropriateness of a separate rate class for a large wholesale customer.

28. **In re: Potomac Electric Power Company**, before the Public Service Commission of the District of Columbia, Formal Case No. 912, on behalf of the Staff of the Public

Service Commission of the District of Columbia, concerning the Application of PEPCO for an increase in retail rates for the sale of electric energy.

29. **Commonwealth of Pennsylvania, House of Representatives**, General Assembly House Bill No. 2273. Oral testimony before the Committee on Conservation, concerning proposed Electromagnetic Field Exposure Avoidance Act.

30. **In re: Hearings on the 1990 Ontario Hydro Demand\Supply Plan**, before the Ontario Environmental Assessment Board, concerning Ontario Hydro's System Reliability Planning and Transmission Planning.

31. **In re: Maui Electric Company**, Docket No. 7000, before the Public Utilities Commission of the State of Hawaii, on behalf of the Division of Consumer Advocacy, concerning MECO's generation system, fuel and purchased power expense, depreciation, plant additions and retirements, contributions and advances.

32. **In re: Hawaiian Electric Company, Inc.**, Docket No. 7256, before the Public Utilities Commission of the State of Hawaii, on behalf of the Division of Consumer Advocacy, concerning need for, design of, and routing of proposed transmission facilities.

33. **In re: Commonwealth Edison Company**, Docket No. 94-0065 before the Illinois Commerce Commission on behalf of the City of Chicago, concerning the capacity needed for system reliability.

34. **In re: Commonwealth Edison Company**, Docket No. 93-0216 before the Illinois Commerce Commission on behalf of the Citizens for Responsible Electric Power, concerning the need for proposed 138 kV transmission and substation facilities.

35. **In re: Commonwealth Edison Company**, Docket No. 92-0221 before the Illinois Commerce Commission on behalf of the Friends of Illinois Prairie Path, concerning the need for proposed 138 kV transmission and substation facilities.

36. **In re: Commonwealth Edison Company**, Docket No. 94-0179 before the Illinois Commerce Commission on behalf of the Friends of Sugar Ridge, concerning the need for proposed 138 kV transmission and substation facilities.

37. **In re: Public Service Company of Colorado**, Docket Nos. 95A-531EG and 95I-464E before the Colorado Public Utilities Commission on behalf of the Office of Consumer Counsel, concerning a proposed merger with Southwestern Public Service Company and a proposed performance-based rate-making plan.

38. **In re: South Carolina Electric & Gas Company, Duke Power Company, and Carolina Power & Light Company**, Docket No. 95-1192-E, before the South Carolina Public Service Commission on behalf of the South Carolina Department of Consumer Advocate, concerning avoided cost rates payable to qualifying facilities.

39. **In re: Lawrence A. Baker v. Truckee Donner Public Utility District**, Case No. 55899, before the Superior Court of the State of California on behalf of Truckee Donner Public Utility District, concerning the reasonableness of electric rates.

40. **In re: Black Hills Power & Light Company**, Docket No. OA96-75-000, before the Federal Energy Regulatory Commission on behalf of the City of Gillette, Wyoming, concerning the Black Hills' proposed open access transmission tariff.

41. **In re: Metropolitan Edison Company and Pennsylvania Electric Company** for Approvals of the Restructuring Plan Under Section 2806, Docket Nos. R-00974008 and R-00974009 before the Pennsylvania PUC on behalf of Operating NUG Group, concerning miscellaneous restructuring issues.

42. **In re: New Jersey State Restructuring Proceeding** for consideration of proposals for retail competition under BPU Docket Nos. EX94120585U; E097070457; E097070460; E097070463; E097070466 before the New Jersey BPU on behalf of the New Jersey Division of Ratepayer Advocate, concerning load balancing, third party settlements, and market power.

43. **In re: Arbitration Proceeding In City of Chicago v. Commonwealth Edison** for consideration of claims that franchise agreement has been breached, Proceeding No. 51Y-114-350-96 before an arbitration panel board on behalf of the City of Chicago concerning electric system reliability.

44. **In re: Transalta Utilities Corporation**, Application No. RE 95081 on behalf of the ACD companies, before the Alberta Energy And Utilities Board in reference to the use and value of interruptible capacity.

45. **In re: Consolidated Edison Company,** Docket No. EL99-58-000 on behalf of The Village of Freeport, New York, before FERC in reference to remedies for a breach of contract to provide firm transmission service on a non-discriminatory basis.

46. **In re: ESBI Alberta Ltd.,** Application No. 990005 on behalf of the FIRM Customers, before the Alberta Energy And Utilities Board concerning the reasonableness of the cost of service plus management fee proposed for 1999 and 2000 by the transmission administrator.

47. **In re: South Carolina Electric & Gas Company,** Docket No. 2000-0170-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new and repowered generating units at the Urquhart generating station.

48. **<u>In re: BGE,</u>** Case No. 8837 on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning proposed electric line extension charges.

49. **<u>In re: PEPCO,</u>** Case No. 8844 on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning proposed electric line extension charges.

50. **<u>In re: GenPower Anderson LLC,</u>** Docket No. 2001-78-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new generating units at the GenPower Anderson LLC generating station.

51. **<u>In re: Pike County Light & Power Company,</u>** Docket No. P-00011872, on behalf of Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning the Pike County request for a retail rate cap exception.

52. **<u>In re: Potomac Electric Power Company and Conectiv,</u>** Case No. 8890, on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning the proposed merger of Potomac Electric Power Company and Conectiv.

53. **<u>In re: South Carolina Electric & Gas Company,</u>** Docket No. 2001-420-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new generating units at the Jasper County generating station.

54. **<u>In re: Connecticut Light & Power Company,</u>** Docket No. 217 on behalf of the Towns of Bethel, Redding, Weston, and Wilton, Connecticut before the Connecticut Siting Council concerning an application for a Certificate of Environmental Compatibility and Public Need for a new transmission line facility between Plumtree Substation, Bethel and Norwalk Substation, Norwalk.

55. **<u>In re: The City of Vernon, California,</u>** Docket No. EL02-103 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting calendar year 2001 transactions.

56. **<u>In re: San Diego Gas & Electric Company et. al.,</u>** Docket No. EL00-95-045 on behalf of the City of Vernon, California before the Federal Energy Regulatory Commission concerning refunds and other monies payable in the California wholesale energy markets.

57. **<u>In re: The City of Vernon, California,</u>** Docket No. EL03-31 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting 2002 transactions.

58. **<u>In re: Jersey Central Power & Light Company,</u>** Docket Nos. ER02080506, ER02080507, ER02030173, and EO02070417 on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

59. **<u>In re: Proposed Electric Service Reliability Rules, Standards, and Indices To Ensure Reliable Service by Electric Distribution Companies,</u>** PSC Regulation Docket No. 50, on behalf of the Delaware Public Service Commission Staff before the Delaware Public Service Commission concerning proposed electric service reliability rules, standards and indices.

60. **<u>In re: Central Maine Power Company,</u>** Docket No. 2002-665, on behalf of the Maine Public Advocate and the Town of York before the Maine Public Utilities Commission concerning a Request for Commission Investigation into the New CMP Transmission Line Proposal for Eliot, Kittery, and York.

61. **<u>In re: Metropolitan Edison Company,</u>** Docket No. C-20028394, on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission concerning the reliability service complaint of Robert Lawrence.

62. **<u>In re: The California Independent System Operator Corporation,</u>** Docket No. ER00-2019 *et al.* on behalf of the City of Vernon, California, before the Federal Energy Regulatory Commission concerning wholesale transmission tariffs, rates and rate structures proposed by the California ISO.

63. **<u>In re: The Narragansett Electric Company,</u>** Docket No. 3564 on behalf of the Rhode Island Department of Attorney General, before the Rhode Island Public Utilities Commission concerning the proposed relocation of the E-183 transmission line.

64. **<u>In re: The City of Vernon, California,</u>** Docket No. EL04-34 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting 2003 transactions.

65. **<u>In re: Atlantic City Electric Company,</u>** Docket No. ER03020110 on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

66. **<u>In re: Connecticut Light & Power Company and the United Illuminating Company,</u>** Docket No. 272 on behalf of the Towns of Bethany, Cheshire, Durham, Easton, Fairfield, Hamden, Middlefield, Milford, North Haven, Norwalk, Orange, Wallingford, Weston, Westport, Wilton, and Woodbridge, Connecticut before the Connecticut Siting Council concerning an application for a Certificate of Environmental Compatibility and Public

Need for a new transmission line facility between the Scoville Rock Switching Station in Middletown and the Norwalk Substation in Norwalk, Connecticut.

67. **In re: Metropolitan Edison Company, Pennsylvania Electric Company, and Pennsylvania Power Company,** Docket No. I-00040102, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning electric service reliability performance.

68. **In re: Entergy Louisiana, Inc.,** Docket No. U-20925 RRF-2004 on behalf of Bayou Steel before the Louisiana Public Service Commission concerning a proposed increase in base rates.

69. **In re: Jersey Central Power & Light Company,** Docket No. ER02080506, Phase II, on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

70. **In re: Maine Public Service Company,** Docket No. 2004-538, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a request to construct a 138 kV transmission line from Limestone, Maine to the Canadian border near Hamlin, Maine.

71. **In re: Pike County Light and Power Company,** Docket No. M-00991220F0002, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning the Company's Petition to amend benchmarks for distribution reliability.

72. **In re: Atlantic City Electric Company,** Docket No. EE04111374, on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning the need for transmission system reinforcement, and related issues.

73. **In re: Bangor Hydro-Electric Company,** Docket No. 2004-771, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a request to construct a 345 kV transmission line from Orrington, Maine to the Canadian border near Baileyville, Maine.

74. **In re: Eastern Maine Electric Cooperatve,** Docket No. 2005-17, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a petition to approve a purchase of transmission capacity on a 345 kV transmission line from Maine to the Canadian province of New Brunswick.

75. **In re: Virginia Electric and Power Company,** Case No. PUE-2005-00018, on behalf of the Town of Leesburg VA and Loudoun County VA before the Virginia State Corporation Commission concerning a request for a certificate of public convenience and necessity for transmission and substation facilities in Loudoun County.

76. **<u>In re: Proposed Electric Service Reliability Rules, Standards, and Indices To Ensure Reliable Service by Electric Distribution Companies,</u>** PSC Regulation Docket No. 50, on behalf of the Delaware Public Service Commission Staff before the Delaware Public Service Commission concerning proposed electric service reliability reporting, standards, and indices.

77. **<u>In re: Proposed Merger Involving Constellation Energy Group Inc. and the FPL Group, Inc.</u>**, Case No. 9054, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the proposed merger involving Baltimore Gas & Electric Company and Florida Light & Power Company.

78. **<u>In re: Proposed Sale and Transfer of Electric Franchise of the Town of St. Michaels to Choptank Electric Cooperative, Inc.,</u>** Case No. 9071, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the sale by St. Michaels of their electric franchise and service area to Choptank.

79. **<u>In re: Petition of Rockland Electric Company for the Approval of Changes in Electric Rates, and Other Relief,</u>** BPU Docket No. ER06060483, on behalf of the Department of the Public Advocate, Division of Rate Counsel, before the New Jersey Board of Public Utilities, concerning electric service reliability and reliability-related spending.

80. **<u>In re: The Complaint of the County of Pike v. Pike County Light & Power Company, Inc.,</u>** Docket No. C-20065942, et al., on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, concerning electric service reliability and interconnecting with the PJM ISO.

81. **<u>In re: Application of American Transmission Company to Construct a New Transmission Line,</u>** Docket No. 137-CE-139, on behalf of The Sierra Club of Wisconsin, before the Public Service Commission of Wisconsin, concerning the request to build a new 138 kV transmission line.

82. **<u>In re: Central Maine Power Company,</u>** Docket No. 2006-487, on behalf of the Maine Public Advocate before the Maine Public Utilities Commission concerning CMP's Petition for Finding of Public Convenience & Necessity to build a 115 kV transmission line between Saco and Old Orchard Beach.

83. **<u>In re: Bangor Hydro Electric Company,</u>** Docket No. 2006-686, on behalf of the Maine Public Advocate before the Maine Public Utilities Commission concerning BHE's Petition for Finding of Public Convenience & Necessity to build a 115 kV transmission line and substation in Hancock County.

84. **<u>In re: Commission Staff's Petition For Designation of Competitive Renewable Energy Zones,</u>** Docket No. 33672, on behalf of the Texas Office of Public Utility Counsel, concerning the Staff's Petition and the determination of what areas should be designated as CREZs by the Commission.

85. **<u>In re: Virginia Electric and Power Company,</u>** Case No. PUE-2006-00091, on behalf of the Towering Concerns and Stafford County VA before the Virginia State Corporation Commission concerning a request for a certificate of public convenience and necessity for electric transmission and substation facilities in Stafford County.

86. **<u>In re: Trans-Allegheny Interstate Line Company,</u>** Docket Nos. A-110172 et al., on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning a request for a certificate of public convenience and necessity for electric transmission and substation facilities in Pennsylvania.

87. **<u>In re: Commonwealth Edison Company,</u>** Docket No. 07-0566, on behalf of the Illinois Attorney General, before the Illinois Commerce Commission, concerning electric transmission and distribution projects promoted as smart grid projects, and the rider proposed to pay for them.

Appendix 3: Qualification Information for Robert M. Fagan

Robert M. Fagan

Senior Associate
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SUMMARY

Mechanical engineer and energy economics analyst with over 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, renewable resource alternatives 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:

- Ongoing analysis of wholesale and retail energy and capacity market issues in New Jersey, including assessment of BGS supply alternatives and demand response options.
- Ongoing analysis of utility-sponsored energy efficiency programs in Rhode Island as part of the Rhode Island DSM Collaborative.
- Analysis of effect of increasing the system benefits charge (SBC) in Maine to increase procurement of energy efficiency and DSM resources; analysis of impact of DSM on transmission and distribution reinforcement need.
- Evaluation of wind energy potential, related transmission issues, and resource planning in Minnesota, Iowa and Indiana.
- Evaluation of wind energy "firming" premium in BC Hydro Energy Call in British Columbia.
- 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 customer participation in 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 and Academic Coursework
Utility Wind Integration Group - Short Course on Integration and Interconnection of Wind Power Plants Into Electric Power Systems (2006).
Regulatory and Legal Aspects of Electric Power Systems – Short Course – University of Texas at Austin (1998)
Illuminating Engineering Society courses in lighting design (1989).
Coursework in Solar Engineering; Building System Controls; and Cogeneration at Worcester Polytechnic Institute and Northeastern University (1984, 1988-89).
Graduate Coursework in Mechanical and Aerospace Engineering – Polytechnic Institute of New York (1985-1986)

SUMMARY OF TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

TESTIMONY

Pennsylvania Public Utility Commission. Direct testimony filed before the Commission on the effect of demand-side management on the need for a transmission line and the level of consideration of potential carbon regulation on PJM's analysis of need for a transmission line. Docket Nos. A-110172 *et al*. Testimony filed October 31, 2007.

Iowa Public Utilities Board. Direct testimony filed before the Board on wind energy assessment in Interstate Power and Light's resource plans and its relationship to a proposed coal plant in Iowa. Docket No. GCU-07-01. Testimony filed October 21, 2007.

New Jersey Board of Public Utilities. Direct testimony before the Board on certain aspects of PSE&G's proposal to use ratepayer funding to finance a solar photovoltaic panel initiative in support of the State's solar RPS. Docket No. EO07040278. Testimony filed September 21, 2007.

Indiana Utility Regulatory Commission. Direct Testimony filed before the Commission addressing a proposed Duke – Vectren IGCC coal plant. Testimony focused on wind power potential in Indiana. Filed on behalf of the Citizens Action Coalition of Indiana, Cause No. 43114 May 14, 2007.

State of Maine Public Utilities Commission. Pre-filed testimony on the ability of DSM and distributed generation potential to reduce local supply area reinforcement needs. Testimony filed before the Commission on a Request for Certificate of Public Convenience and Necessity to Build a 115 kV Transmission Line between Saco and Old Orchard Beach. Testimony filed jointly with Peter Lanzalotta, on behalf of the Maine Public Advocate. Docket No. 2006-487, February 27, 2007.

Minnesota Public Utilities Commission. Rebuttal Testimony on wind energy potential and related transmission issues in the Certificate of Need proceeding for the Big Stone II coal-fired power plant proposal. In the Matter of the Application by Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota and In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota. OAH No. 12-2500-17037-2 and OAH No. 12-2500-17038-2; and MPUC Dkt. Nos. CN-05-619 and TR-05-1275. December 8, 2006.

British Columbia Utilities Commission. In the Matter of BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan. Pre-filed Evidence filed on behalf of the Sierra Club (BC Chapter), Sustainable Energy Association of BC, and Peace Valley Environment Association. October 6, 2006. Testimony addressing the “firming premium” associated with 2006 Call energy, liquidated damages provisions, and wind integration studies.

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 New Jersey Department of the Ratepayer advocate, ongoing analysis of myriad issues affecting New Jersey electricity consumers, including: review of BGS supply structures, participation in working group designing demand side response pilot programs, analysis of PSE&G solar PV initiatives, review of ongoing FERC proceedings on PJM transmission planning and impacts on New Jersey. (2007)

For the Maine Office of Public Advocate, technical review of issues pertaining to potential withdrawal of Maine utilities from the ISO NE RTO. Also, technical review and expert testimony preparation on energy efficiency and demand side response resource impact on sub-transmission supply needs in the Saco Bay area. (2006-2007)

For the Minnesota Center for Environmental Advocacy, preparation of expert testimony on wind energy in Minnesota and the upper Midwest in the case against the proposed Big Stone II coal plant. (2006)

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)

Energy Efficiency and Demand Side Management

For the Pennsylvania Office of Consumer Advocate, analysis of the ability of demand-side management efforts to reduce peak loading and affect the need for the 502 Junction – Prexy 500 kV line proposed by Allegheny Power. (2007 – 2008)

For the New Jersey Division of Rate Counsel, Department of Public Advocate, participation in demand response working group and assessment of proposal for state-sponsored demand response program. (2007)

For the Rhode Island Division of the Public Utilities Commission, ongoing technical support and participation in the statewide DSM collaborative process. (2007)

For the Maine Office of the Public Advocate, evaluated the ability of DSM and distributed generation to affect the need for transmission and distribution system reinforcement in the Saco Bay area of Central Maine Power's service territory. (2007)

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. 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.

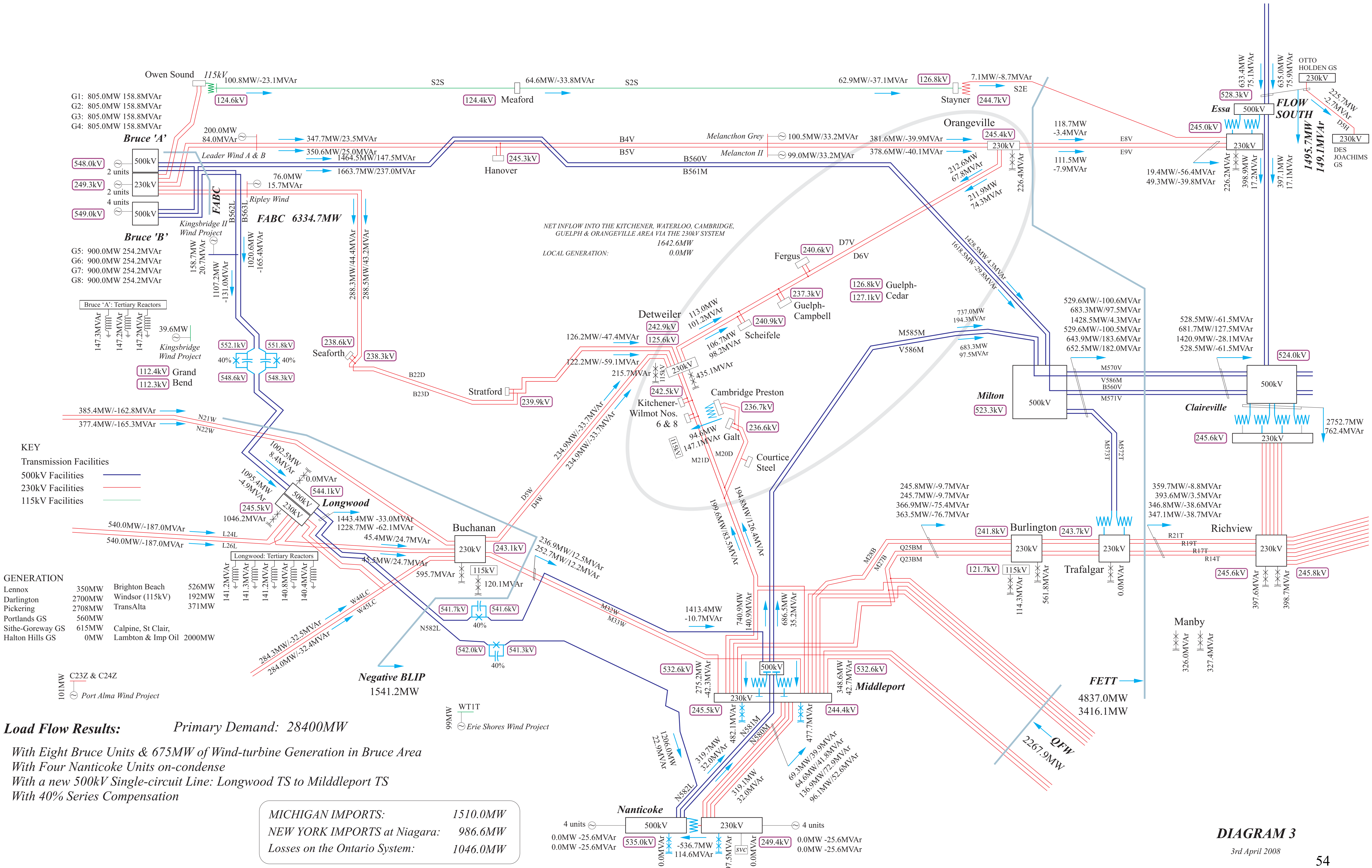
Impact Evaluation of Commonwealth Electric's Customized Rebate Program. With P.J. Spinney and G.C. Watkins. Charles River Associates, Initial and Updated Reports, April 1994, April 1995, and April 1996.1995 updated report filed with the MDPU, April28, 1995, Docket # DPU 95-2/3-CC-I. The initial report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

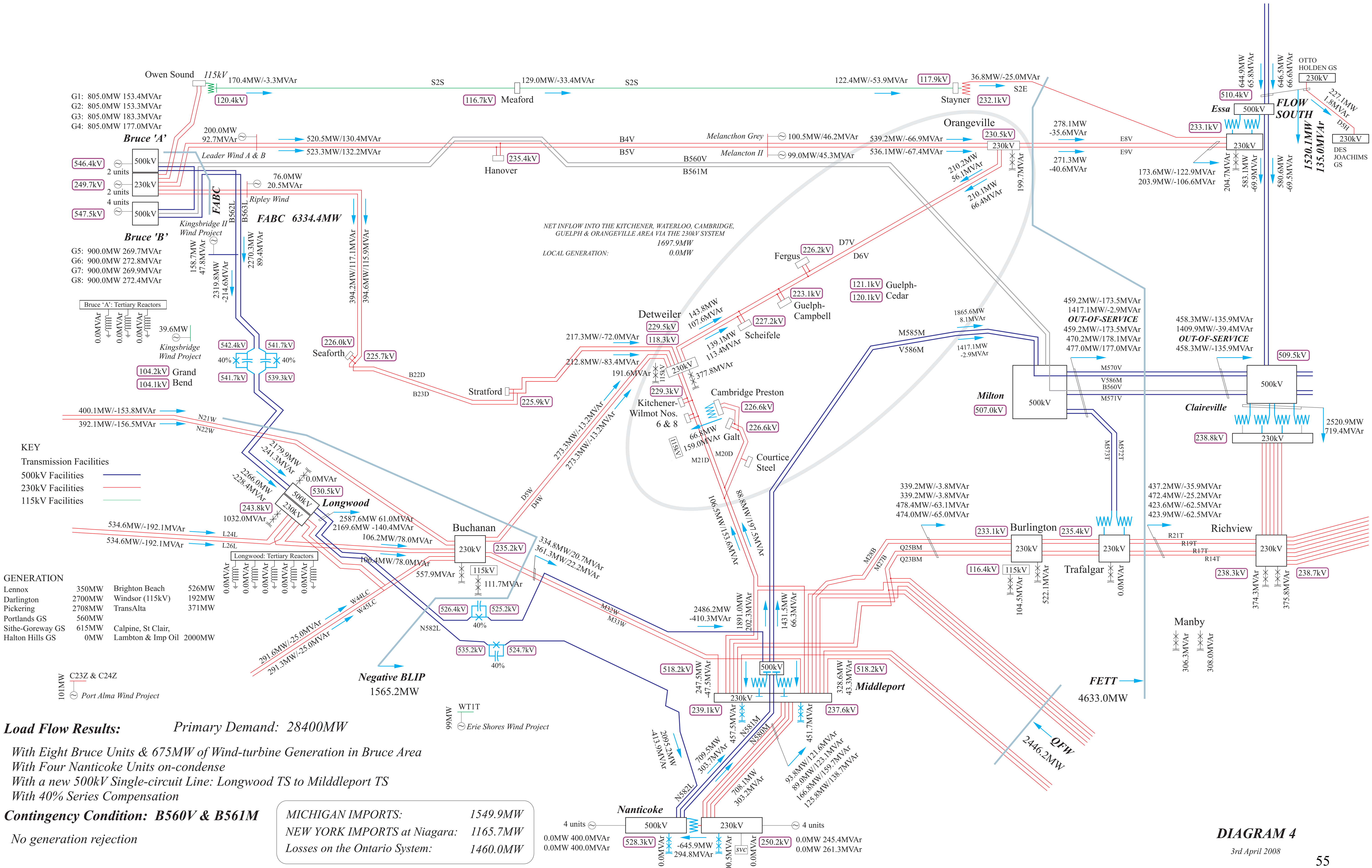
The Role of Trade Allies in C&I DSM Programs: A New Focus for Program Evaluation, Paper authored by Peter J. Spinney (Charles River Associates) and John Peloza (Wisconsin Electric Power Corp.). Presented by Bob Fagan at the Sixth International Energy Evaluation Conference, Chicago, Illinois, August 1993.

Resume dated December 2007.

Appendix 4: Result Diagrams from Load Flow Studies



Owen Sound
115kV
100.8MW/-23.1MVAr
S2S
64.6MW/-33.8MVAr
Meaford
62.9MW/-37.1MVAr
Stayner
7.1MW/-8.7MVAr
S2E
G1: 805.0MW 158.8MVAr
G2: 805.0MW 158.8MVAr
G3: 805.0MW 158.8MVAr
G4: 805.0MW 158.8MVAr
Bruce 'A'
Leader Wind A & B
Ripley Wind
Hanover
Melancthon Grey
Melancthon II
Orangeville
B4V
B5V
B560V
B561M
E8V
E9V
Essa
FLOW SOUTH
1495.7MW
149.1MVAr
OTTO HOLDEN GS
DES JOACHIMS GS
Bruce 'B'
G5: 900.0MW 254.2MVAr
G6: 900.0MW 254.2MVAr
G7: 900.0MW 254.2MVAr
G8: 900.0MW 254.2MVAr
Kingsbridge II Wind Project
FABC
FABC 6334.7MW
NET INFLOW INTO THE KITCHENER, WATERLOO, CAMBRIDGE, GUELPH & ORANGEVILLE AREA VIA THE 230kV SYSTEM
1642.6MW
LOCAL GENERATION: 0.0MW
Bruce 'A': Tertiary Reactors
Kingsbridge Wind Project
Grand Bend
Seaforth
Stratford
Detweiler
Fergus
Guelph-Campbell
Scheifele
Guelph-Cedar
Cambridge Preston
Kitchener-Wilmot Nos. 6 & 8
Galt
Courtice Steel
Milton
Claireville
M585M
V586M
Longwood
Longwood: Tertiary Reactors
Buchanan
N21W
N22W
L24L
L26L
W44LC
W45LC
N582L
D5W
D4W
M32W
M33W
Burlington
Trafalgar
Richview
Manby
Middleport
Nanticoke
FETT
4837.0MW
3416.1MW
QFW
2267.9MW
Negative BLIP
1541.2MW
KEY
Transmission Facilities
500kV Facilities
230kV Facilities
115kV Facilities
GENERATION
Lennox 350MW
Darlington 2700MW
Pickering 2708MW
Portlands GS 560MW
Sithe-Goreway GS 615MW
Halton Hills GS 0MW
Brighton Beach 526MW
Windsor (115kV) 192MW
TransAlta 371MW
Calpine, St Clair, Lambton & Imp Oil 2000MW
C23Z & C24Z
Port Alma Wind Project
WT1T
Erie Shores Wind Project
Load Flow Results:
Primary Demand: 28400MW
With Eight Bruce Units & 675MW of Wind-turbine Generation in Bruce Area
With Four Nanticoke Units on-condense
With a new 500kV Single-circuit Line: Longwood TS to Milddleport TS
With 40% Series Compensation
MICHIGAN IMPORTS: 1510.0MW
NEW YORK IMPORTS at Niagara: 986.6MW
Losses on the Ontario System: 1046.0MW
DIAGRAM 3
3rd April 2008



Load Flow Results: *Primary Demand: 28400MW*

With Eight Bruce Units & 675MW of Wind-turbine Generation in Bruce Area
With Four Nanticoke Units on-condense
With a new 500kV Single-circuit Line: Longwood TS to Milddleport TS
With 40% Series Compensation

Contingency Condition: B560V & B561M

No generation rejection

MICHIGAN IMPORTS:	*1549.9MW*
NEW YORK IMPORTS at Niagara:	*1165.7MW*
Losses on the Ontario System:	*1460.0MW*

DIAGRAM 4

3rd April 2008