David I. Poch Barrister tel. (613) 264-0055 fax (613) 264-2878

31 July 2015

Ontario Energy Board
2300 Yonge St., 27th Floor
Toronto, ON
M4P 1E4

Attn: Ms Kirsten Walli
Board Secretary

By electronic filing and e-mail

Dear Ms Walli:

Re: EB-2015-0029, EB-2015-0049 – Union and Enbridge 2015-20 Gas DSM – GEC evidence of Paul Chernick, Resource Insight Inc.

Attached please find Mr. Chernick's prefiled evidence in the above-noted matters.

Sincerely,

David Poch
Cc: all parties

1649 Old Brooke Road, Maberly, Ontario K0H 2B0 e-mail: dpoch@eelaw.ca

Exhibit L.GEC.2

PROVINCE OF ONTARIO

BEFORE THE ENERGY BOARD

2015-2020 DSM Plans of Enbridge Gas	**)**	
Distribution and Union Gas	**)**	**EB-2015-0029/0049**

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE GREEN ENERGY COALITION

Resource Insight, Inc.

JULY 31, 2015

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TABLE OF EXHIBITS

I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Appendix A.

Q: Have you previously presented evidence before the Ontario Energy Board?

A: Yes. I filed evidence and/or testified before the Ontario Environmental Assessment Board in Ontario Hydro's Demand/Supply Plan hearings in 1992, and before the OEB in the following thirteen dockets:

- EBRO 490, DSM cost recovery and lost-revenue adjustment mechanism for Consumers Gas.
- EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas.
- RP-1999-0034, performance-based rates for electric distribution utilities.
- RP-1999-0044, Ontario Hydro transmission-cost allocation and rate design.
- RP-1999-0017, Union Gas proposal for performance-based rates.
- RP-2002-0120, Ontario transmission-system code.
- RP-2004-0188, cost recovery and DSM for electric-distribution utilities
- EB-2005-0520, rate design and cost allocation for Union Gas firm customers.
- EB-2006-0021, gas utility DSM planning and cost recovery.
- EB-2007-0707, review of Ontario Power Authority's Integrated Power System Plan.
- EB-2007-0905, Ontario Power Generation (OPG) prescribed-facilities rate for 2009–2010.
- EB-2010-0008, OPG prescribed-facilities rate for 2011–2012.

- EB-2012-0451/EB-2012-0433/EB-2013-0074, Enbridge's and Union's Leave To Construct Applications for the Greater Toronto Area (GTA) pipeline expansions.

In addition, I have assisted my clients in preparation of comments in various proceedings, including the distributed generation consultation (EB-2007-0630), the electric distribution rate design proceeding (EB-2007-0031) the distribution-utility decoupling case (EB-2010-0060), and incentive rate making for OPG's prescribed generation assets (EB-2012-0340).

Q: Have you testified previously in utility proceedings in other jurisdictions?

A: Yes. I have testified nearly three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including a total of over twenty proceedings in Alberta, British Columbia, Manitoba, Nova Scotia, and Quebec; and proceedings in over thirty states and two U.S. Federal agencies (NRC and FERC).

These testimonies are listed in my qualifications.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Green Energy Coalition.

Q: What is the purpose of your testimony?

A: My clients have asked me to review the treatment by Enbridge and Union (collectively, the utilities) of a set of issues related to the costs to Ontario gas consumers avoidable through load reductions from demand-side management (DSM). I have focused on the following issues:

- The benefits to all Ontario gas consumers of reductions in market gas prices due to reductions in gas demand, widely known as demand-reduction-induced price effects (DRIPE).
- The benefits to the gas-utility customers and all Ontarians of reduced carbon emissions, reducing the cost of meeting the Province's targets for carbon reductions.
- Re-estimating the benefits to the gas-utility customers of avoided local distribution costs.
- Reviewing the utilities' avoided supply costs, as best I can in light of the utilities refusal to provide even the most basic documentation of their assumptions regarding the prices of gas at various points, transport, and storage services, or constraints on use of those resources.

I provided my preliminary results to Chris Neme of Energy Futures Group as inputs for his analysis of the companies' 2015–2020 DSM portfolios.

A. Conclusions and Recommendations

Q: Please summarize your conclusions.

A: I conclude that the utilities have not provided even the most minimal documentation of their derivation of avoided supply costs, and that those avoided supply costs are probably understated. In addition, the utilities have understated avoided distribution costs, ignored the likely costs of carbon controls, and failed to reflect the benefit to Ontario gas consumers of lower market prices resulting from reduced consumption.

Furthermore, the utilities have not addressed or quantified the effects of DSM that would tend to offset the costs of the programs to non-participants.

Q: What are your recommendations to the Board regarding the issues that you consider in this testimony?

A: I have three sets of recommendations. First, the utilities' projections of avoided costs should be increased to correct omission or understatement of a number of avoided-cost components, as follows:

- Both utilities should incorporate the value of supply-level gas-cost suppression at 0.76¢/m^3, as an additional component of avoided costs.
- Both utilities should incorporate a market value of carbon, starting at about 5.1¢/m^3 in 2017 and rising over time in a manner similar to that I show in Table 3.
- Both utilities should include an interim adder of about 9.5¢/m^3 in their avoided costs, to reflect the non-energy benefits of DSM other than carbon mitigation.[1]
- Both utilities should include an interim avoided distribution cost of \$3,500/10^3m^3 of design-day peak, or about 4.9¢/m^3 of annual space-heating use and 1.4¢/m^3 of annual base load. This would both correct the understatements in Enbridge's analysis and correct Union's error in failing to differentiate avoided distribution costs among load shapes.
- Enbridge should revise its avoided costs to include real gas escalation after 2024, of approximately 2% annually above inflation.

In addition, the utilities should engage in a transparent and cooperative process to improve their avoided-cost estimates in the following ways:

[1] I derive this value in Section III.B.2, below.

- Estimating the extent to which reductions in Ontario gas load reduces the price of gas delivered to Ontario (e.g., at Dawn), compared to production-area reference points.
- Incorporating Ontario's carbon mitigation plan, as that develops.
- Ensuring that the SENDOUT model properly accounts for potential savings between the base case and the DSM cases from the following causes:
    - reduction in existing commitments to pipeline capacity;
    - avoidance of new commitments to pipeline capacity;
    - release of pipeline capacity, when contract quantities cannot be reduced;
    - reduction in existing storage capacity commitments, including injection, withdrawal and storage capacity;
    - avoidance of new storage commitments;
    - reduction of the costs of utility-owned upstream resources (e.g., Union's Dawn storage and Dawn-Parkway pipeline capacity, Enbridge's GTA Segment A) through release, resale, or reallocation.

Third, before relying on any rate impact analysis in constraining DSM budgets, the Board and utilities should recognize that a number of components of avoided costs reduce costs for non-participants, such as avoided distribution, avoided carbon charges, suppression of market prices, and the difference between avoided and average commodity prices.

B. Policy Context

Q: Why are avoided costs important for energy-efficiency policy and implementation?

A: Avoided costs establish the value of energy efficiency to inform utility planning. In its Framework and Filing Guidelines, the Board properly requires that all avoidable costs be included in utility avoided-cost estimates. Failure to include all avoidable costs can lead to a cascading series of errors which undervalue conservation and lead to underinvestment in energy efficiency and an overinvestment in more expensive supply.

For example, if estimates of avoidable costs used in conservation potential studies are too low then measures and program options that should be included in the study would be considered not cost-effective and would be rejected, reducing the study's conservation potential results. Subsequent program planning may leave out measures and program options that are cost-effective, again resulting in lower energy efficiency targets. Ultimately, an under-investment in cost-effective energy efficiency requires additional higher-cost supply, increasing consumers' costs of natural gas services unnecessarily.

III. Avoided Costs

Q: What topics will you address in this part of your testimony?

A: In successive sections, I discuss the following issues:

- the effects of load reductions on market gas prices,
- the value of avoided carbon emissions,
- the difference between avoidable and average costs of gas,
- avoidable distribution costs,

- the utilities' failure to document the derivation of their avoided supply costs,
- apparent understatements of the utilities' supply costs.

A. Demand-Reduction-Induced Price Effects

Q: How does gas conservation affect the price of gas purchased for the remaining load?

A: Reduced gas consumption reduces both the market price of natural gas in North America and the market price of transportation to deliver gas to the citygate. The suppression of energy-market prices due to reductions in demand is often called the demand reduction-induced price effect, or DRIPE.

The Minister of Energy has asked,

> Building on the principle of the non-energy benefit adder…the Board consider…how such potential DSM benefits as…natural gas price suppression may be used to screen prospective DSM programs and inform future budgets." (Letter of 4 February 2015)

1. Supply-Level Price Effects

Q: Have any previous studies estimated the effect of reductions in gas consumption on prices in the continental gas market?

A: Yes. Table 1 summarizes the results of a number of analyses from the period 1998–2007 that estimated the effect on continental gas prices of reducing gas use with gas or electric energy-efficiency programs and/or renewable energy.[2] Most of these studies used EIA's National Energy Modeling System,

[2]While there are regional differences in gas prices due to pipeline congestion, most of the natural-gas price in most locations at most times is determined by the total balance of load and supply across the US and Canada.

which is also used in the Annual Energy Outlook.[3] Table 1 shows results for 2020, except for the ACEEE study, which estimated results in 2008.

Most of these analyses estimated that a 1% reduction in US gas consumption would reduce gas prices by about 1%–3%. For the current forward Henry Hub supply prices for 2016–2020, a price reduction of 1%–3% would be about US $0.034–$0.10/MMBtu or about $0.001–$0.004/m^3 (in U.S. dollars). For that same time period, EIA forecasts that total US consumption of natural gas will be about 25 quads (or billion MMBtu).

Table 1: Estimates of Gas Price Suppression from Reduced Usage

Author	**Reduction in U.S. Gas Consumption** (quads)	**Gas Wellhead Price Reduction $US/Dth** (2000$)	**$US/Dth per quad** (2000$)
EIA (1998)	1.12	$0.34	$0.30
EIA (1999)	0.41	$0.19	$0.46
EIA (2001)	1.45	$0.27	$0.19
EIA (2001)	3.89	$0.56	$0.14
EIA (2002a)	0.72	$0.12	$0.17
EIA (2002a)	1.32	$0.22	$0.17
EIA (2003)	0.48	$0.00	$0.00
UCS (2001)	10.54	$1.58	$0.15
UCS (2002a)	1.28	$0.32	$0.25
UCS (2002a)	3.21	$0.55	$0.17
UCS (2002b)	0.72	$0.05	$0.07
UCS (2003)	0.10	$0.14	$1.40
UCS (2004a)	0.49	$0.12	$0.24
UCS (2004a)	1.80	$0.07	$0.04
UCS (2004b)	0.62	$0.11	$0.18
UCS (2004b)	1.45	$0.27	$0.19
Tellus (2002)	0.13	$0.00	$0.00
Tellus (2002)	0.23	$0.01	$0.04
Tellus (2002)	0.28	$0.02	$0.07
ACEEE (2003)	1.35	$0.76	$0.56

[3]The ACEEE study used the proprietary model of Energy and Environmental Analysis, Inc.

Q: Did you use these results in your estimate of supply DRIPE for Ontario?

A: No. The structure of natural gas supply has changed considerably since 2007, with the growing importance of shale gas and the transition from forecasts of large LNG imports into North America to forecasts of significant LNG exports. As a result, I did not use these older analyses to estimate gas-supply DRIPE.

Q: How did you estimate supply DRIPE?

A: I used sensitivity analyses the EIA ran for its Annual Energy Outlook reports in 2012 and 2014.[4] Table 2 lists the AEO cases that change natural gas demand without affecting the gas supply curve.[5] Table 2 also provides EIA's projection of the changes in gas consumption (in quads or billion MMBtu or trillion cubic feet), and Henry Hub price (in 2010 US$/MMBtu or 2012 US$/MMBtu) from the AEO reference case in 2020.[6]

[4]The 2015 AEO is only a partial update, and does not consider the full range of sensitivities modeled in the 2012 and 2014 AEO reports.

[5]For example, I left out the sensitivity cases that changed the gas resource base or gas-production technology, which would shift the gas supply curve.

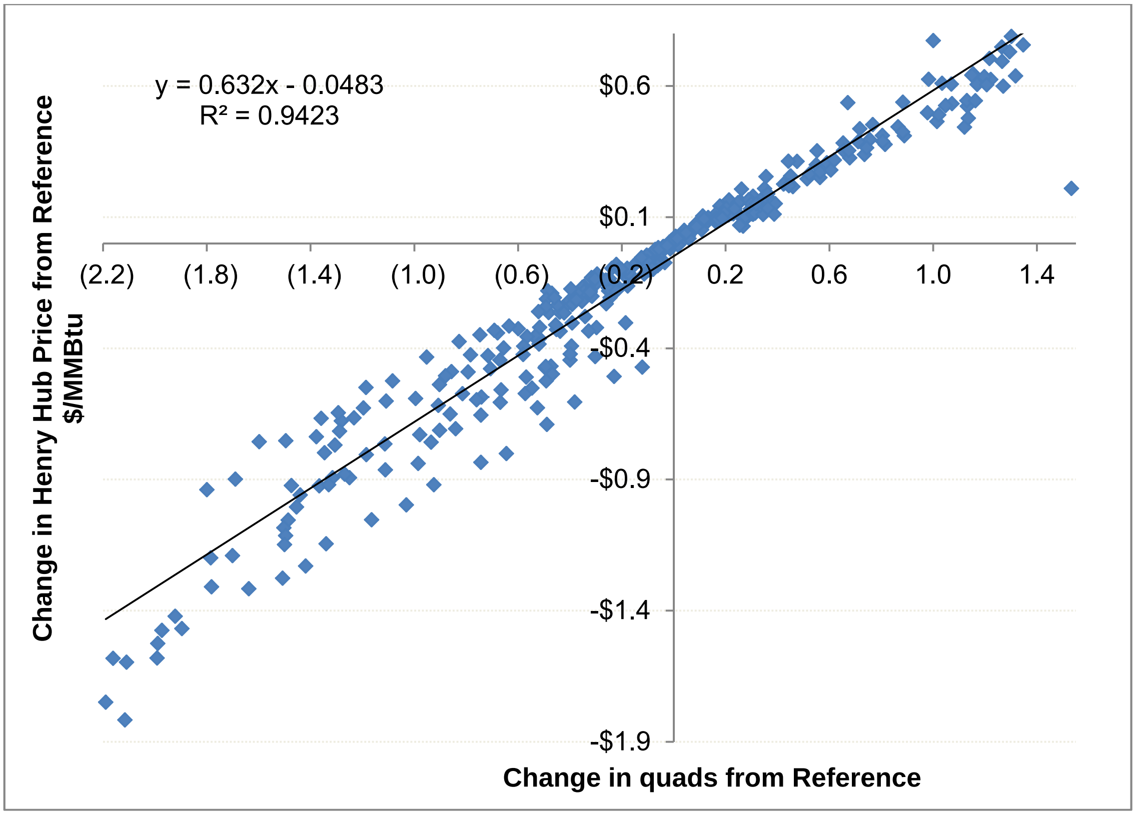
[6]A quad is also about 1,055 petajoule and an MMBtu is about 1.05 Gj.

Table 2: Selected AEO Gas-Demand Sensitivity Cases

	AEO 2012 Changes from 2020 Reference Case		AEO 2014 Changes from 2020 Reference Case	
Forecast Case	Consumption (Quads)	Henry Hub (2010$/Dth)	Consumption (Quads)	Henry Hub (2012$/Dth)
High economic growth	0.48	0.31	0.93	0.22
Low economic growth	−0.53	-0.35	−0.90	0.14
Low nuclear	0.07	0.05		
High nuclear	0	0.01	−0.19	−0.01
Low coal cost	−0.32	−0.2	−0.38	−0.07
High coal cost	0.45	0.26	0.64	0.17
Residential & commercial demand technology				
Existing	0.37	0.17	0.78	0.25
High	−0.49	−0.47	−0.94	0.12
Best	−0.74	−0.83	−1.28	0.08
High coal retirement	0.36	0.17	1.25	0.37
Low renewable cost	−0.08	−0.1	−0.17	−0.01
Extended taxes and standards for efficiency & renewables	−0.15	−0.08	0.23	0.15
No sunset on tax policies for efficiency & renewables	−0.06	−0.02	0.21	0.01

Figure 1 plots those changes from the reference case, over all the years reported in AEO 2012. The results are remarkably linear, with the small changes in the early years clustered near the origin and the large changes in later years closer to the ends of the trend line.

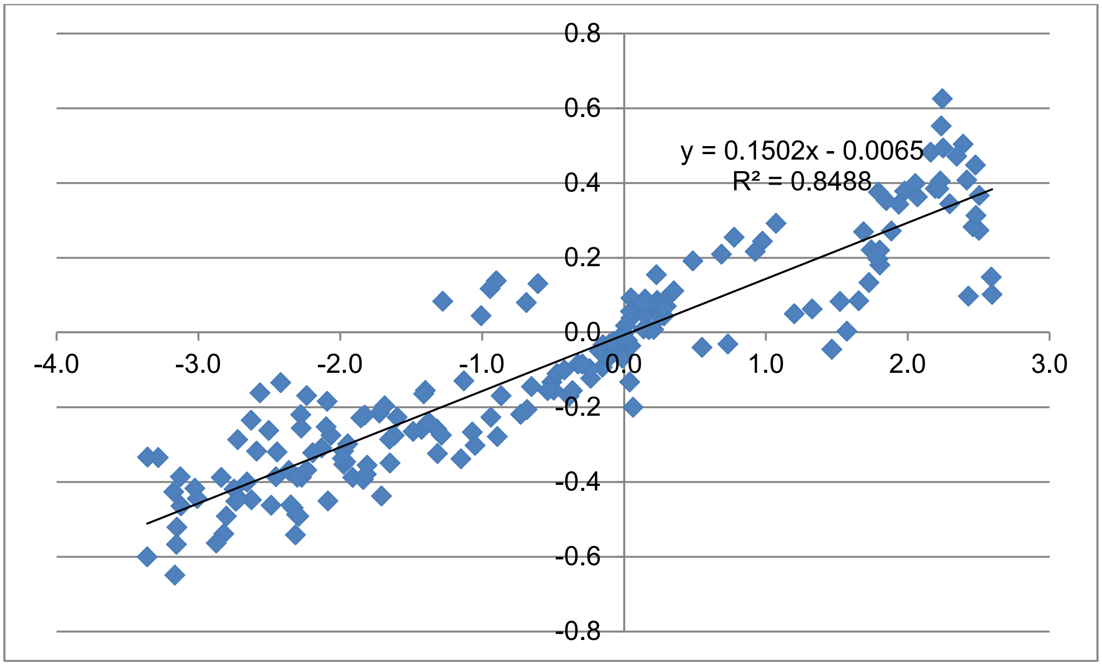
Figure 1: Gas Demand and Price Changes, AEO 2012



The trend line in Figure 1 implies a $0.632/MMBtu decrease in Henry Hub gas price (in 2010 dollars) for every quad (billion MMBtu) decrease in annual gas consumption. Escalated to 2015 U.S. dollars (a 9.1% increase), and converted to Canadian dollars at the average of the exchange rate futures for 2016–2020 (1.26), this slope equals $0.0012/m^3 per 10^{9}m^3 saved.

The same cases in 2014 had greater changes in natural gas demand and lower changes in Henry Hub price. Figure 2 plots those changes from the reference case, over all the years reported in AEO 2014.

Figure 2: Gas Demand and Price Changes, AEO 2014



The regression line in Figure 2 implies a \$0.15/MMBtu decrease in Henry Hub gas price for every quad decrease in annual gas consumption, or \$0.00027/m^3 per $10^9 m^3$ saved (in 2015 Canadian dollars), roughly a quarter of the slope in the 2012 sensitivities.

The AEO data do not appear to show any significant decay in the price-reduction values over time. The AEO gas prices (at least after the first few years) reflect the full long-term costs of gas development, not just the operation of existing wells. The shape of the scatter plots in Figure 1 and Figure 2 do not suggest strong effects of either decay (which would produce an S curve, with the out years leveling off) or accumulating effects (which would result in the curves becoming steeper in the out years, more extreme than the trend lines). Such accumulation could result from the effect of usage rates on the marginal cost of extraction for a finite resource.[7] Lower gas usage in 2016 would leave more low-cost gas in the ground to meet demand in 2017, causing the effect to accumulate over time. A program that saves 100 Tj annually from 2015 onward would have kept another 500 Tj in the ground by 2020, in addition to reducing 2020 demand by 100 Tj. This accumulation effect may offset any factors that would reduce the price effect over time.

Q: How does that coefficient of price change per conserved Gj translate to a savings to Ontario consumers as a result of conserved gas?

A: The effect of this change in price on Ontario consumer's bills, per m^3 conserved, is the product of the $0.00027/$m^3$ per $10^9 m^3$ saved (using the lower 2014 AEO estimates) times the annual gas use in Ontario (about 1,050,000 Tj or 28.2 $10^9 m^3$).[8] The product of a $0.00027/$m^3$ price reduction per $10^9 m^3$ saved times 28.2 $10^9 m^3$ is a benefit to Ontario of 0.76¢ in reduced gas bills per m^3 conserved, in addition to the benefit of buying less gas (which is the direct avoided supply cost).

Most of these benefits will flow directly to all natural gas consumers through their gas bills (whether they participate in the DSM programs or not), while about 20% will flow through the rates charged by the gas-fired generators under contract to the IESO, or the costs of steam in district-heating systems.

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[7]As technology changes, the size of the resource changes, but once gas is removed from the ground, it is gone forever. Less gas will be available from that play in the future, forcing the marginal supply to more expensive plays.

[8]Statistics Canada, Report on Energy Supply and Demand in Canada–2013 Preliminary Release, February 23, 2015 Table 2-8; www.statcan.gc.ca/pub/57-003-x/2015002/t037-eng.pdf.

2. Transportation Price Effects

Q: How do load reductions affect the costs of gas transportation?

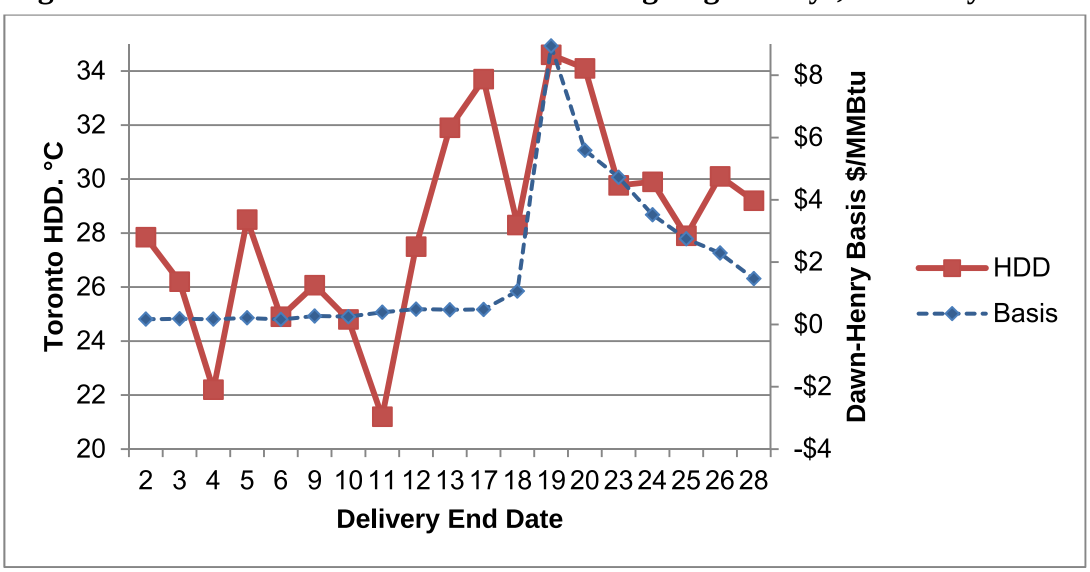
A: Reductions in gas loads reduce the market-price difference (or basis) from supply areas to consumption areas.

Q: Do market prices for gas in Ontario vary with load?

A: Yes. That pattern is apparent in the monthly data for futures prices at Dawn in Exhibit B.T9.Union.GEC.63 (part b and Attachment 1). Prices at Dawn vary much more between summer and winter than those in the producing areas (such as Empress), based on market expectations of future weather. Actual monthly prices vary even more between mild and cold months, and daily prices vary even more dramatically, mostly as a function of load.

Figure 3 shows how the basis from Henry Hub to Dawn increased after a cold snap in the middle of the month, measured in heating degree days (HDD) at Toronto. The basis moved toward normal levels, after temperatures warmed somewhat at the end of the month.

Figure 3: Dawn Basis US$ and Toronto Heating Degree Days, February 2015



Pinning down a precise relationship between load and market prices is difficult, mostly because daily loads for geographical areas are not readily available and because it is not easy to define the geographic area that drives the basis between two points. For example, the basis from Henry Hub to Dawn will depend on Ontario load, but also load downstream from Ontario (in Quebec, the Maritimes, and New England) and between Henry Hub and Dawn. In addition, for an area with a large amount of storage, the market price on any day may be affected by the status of that storage and the weather and load forecasts.

Q: Is much of Ontario's gas supply sourced from spot purchases in the market areas?

A: It appears so. Union reports that its marginal source of gas for its southern area is spot purchases at Dawn.[9] Considering the uncertainty in their dispatch, most Ontario electric generators probably also purchase all their gas transportation at market prices. Reducing gas-transportation costs will tend to reduce electric market prices, in the periods for which gas sets the market price. Most interruptible gas-transportation customers also probably purchase their gas on the spot markets.

Q: Have you been able to estimate the magnitude of the effect of reduced gas usage on market transportation prices for other regions?

A: Yes. Using daily prices and daily pipeline delivery data, I estimated a New England three-month winter gas basis of $178/MMBtu per quad saved under

[9] Enbridge does not appear to have provided any similar generalizations regarding supply sources.

the tightest supply conditions, falling to about $22/MMBtu per quad saved as transmission is added.[10]

In addition, I examined the historical relationship between monthly consumption in the Northeast and basis from Henry Hub to the TETCo M-3 zone, which is a major pricing point for generation in eastern Pennsylvania, New Jersey, and surrounding regions. I defined the Northeast as including the states served by the M-3 zone and those downstream: Pennsylvania, New Jersey, New York, Massachusetts, Rhode Island, Connecticut and New Hampshire. I found that reducing winter gas consumption by one quad (roughly 1,000 Pj) reduces basis by $0.021/MMBtu, or about $0.001/m^3. If this basis price sensitivity is applicable to Ontario, each m^3 conserved would reduce the basis portion of Ontario gas bills by about 1¢, depending on the percentage of gas that is purchased in or near Ontario, as opposed to being purchased in the producing areas (such as at Empress) and transported to the city gate at regulated rates.

B. Carbon Pricing

1. Estimates of Carbon Prices

Q: What subjects do you cover in this section?

A: In this section, I discuss Ontario's commitment to reduce carbon emissions through a cap-and-trade program, and I estimate the value to the utilities' gas

[10] Hornby, Rick, David White, John Rosenkranz, Ron Denhardt, Elizabeth Stanton, Jason Gifford, Bob Grace, Max Chang, Patrick Luckow, Thomas Vitolo, Patrick Knight, Paul Chernick, Ben Griffiths, and Bruce Biewald. 2013. "Avoided Energy Supply Costs in New England: 2013 Report." Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company. The estimation cited is at 7-26.

customers of reducing carbon emissions. The allowance mechanism would convert the cost of carbon emissions, which are currently an externality created by gas use in Ontario and borne by people and the environment globally, to an internalized charge on gas use in Ontario.

Q: Are you familiar with Ontario's climate change policies as they may affect avoided costs and cost-effectiveness screening?

A: I am aware that Ontario has had greenhouse gas (GHG) reduction targets in place for a number of years, including one for the year 2020, at the end of the period covered by the utilities' proposed DSM Plans. Progress reports indicate that the province is currently expected to fall short of the 2020 targets by 19 megatonnes (about 12% of the target) without further actions.[11]

The Province has also recently joined the Western Climate Initiative with Quebec, California, and other jurisdictions, and adopted a goal for 2030 of a 37% reduction in GHG emissions. That reduction would correspond to roughly a 2.5% annual reduction in emissions per year over the next 15 years. Achieving these goals and minimizing the burden on the Ontario economy will require maximizing the acquisition of cost-effective energy efficiency.

Ontario has also recently announced that it will introduce a carbon pricing policy in the form of a cap-and-trade program. The system is being designed in a process anticipated to continue into the autumn of this year.[12]

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[11]Feeling the Heat: Greenhouse Gas Progress Report 2015, Environmental Commissioner of Ontario, July 2015, at 13.

[12]news.ontario.ca/ene/en/2015/04/how-cap-and-trade-works.html

Specifically for natural-gas DSM programs, the Minister of Energy has asked.

> Building on the principle of the non-energy benefit adder…the Board consider…how such potential DSM benefits as carbon reduction… may be used to screen prospective DSM programs and inform future budgets. (Letter of 4 February 2015)

Q: How did you estimate the internalized costs of carbon charges?

A: I relied on the 2015 Carbon Dioxide Price Forecast from Synapse Energy Economics, which includes an extensive summary of recent carbon-pricing forecasts from utilities, government agencies, and third parties. Many of those analyses are driven by the emission reductions required under the U.S. Clean Power Plan. I used Synapse's mid-case projection of carbon allowance prices. This projection assumes that carbon caps take effect in 2020, starting at $20/ton in 2014 U.S. dollars, rising linearly to $35 in 2030 and $61.50 in 2040.[13]

I multiplied that price by emissions of 1.89 kg of CO_2 per m^3, and adjusted to Canadian dollars at the current 1.27 exchange rate, to get internalized carbon prices of $0.053/$m^3$ of gas burned in 2020, $0.093/$m^3$ in 2030 and $0.163/$m^3$ in 2040. Table 3 provides the Synapse price projection and the equivalent price in Canadian dollars per m^3 of gas burned.

[13]Luckow, Patrick, Elizabeth Stanton, Spencer Fields, Bruce Biewald, Sarah Jackson, Jeremy Fisher, and Rachel Wilson. 2015. "2015 Carbon Dioxide Price Forecast." Cambridge, Mass.: Synapse Energy Economics. As I discuss below, Synapse's estimate is lower than the U.S. government's estimate of the social cost of carbon. Synapse's carbon prices would add about half as much to the electric avoided costs used by the gas utilities as the 15% non-energy benefits adder.

Table 3: Synapse 2015 CO_2 Allowance Price Projections (Mid Case)

	2014 US$/ton CO_2	2014 Can$/$m^3$
2020	$20.00	$0.053
2021	$21.50	$0.057
2022	$23.00	$0.061
2023	$24.50	$0.065
2024	$26.00	$0.069
2025	$27.50	$0.073
2026	$29.00	$0.077
2027	$30.50	$0.081
2028	$32.00	$0.085
2029	$33.50	$0.089
2030	$35.00	$0.093
2031	$37.65	$0.100
2032	$40.30	$0.107
2033	$42.95	$0.114
2034	$45.60	$0.121
2035	$48.25	$0.128
2036	$50.90	$0.135
2037	$53.55	$0.142
2038	$56.20	$0.149
2039	$58.85	$0.156
2040	$61.50	$0.163

Q: How do these estimates of CO_2 prices compare to estimates of the social costs of carbon emissions?

A: The US government has developed estimates of the social cost of carbon (SCC). The Interagency Working Group found that "the average SCC from three integrated assessment models (IAMs), at [real] discount rates of 2.5, 3, and 5 percent," with a 95th-percentile estimate at a 3% rate, would be as shown in Table 4. These values are generally significantly higher than the Synapse price projections.[14]

Table 4: Social Cost of CO_2, 2014 US Dollars per metric ton CO_2)

	Discount Rate and Estimate Statistic			
	5% Average	3% Average	2.5% Average	3% 95th percentile
2015	$12	$40	$62	$117
2020	$13	$47	$69	$140
2025	$16	$51	$76	$150
2030	$18	$56	$81	$170
2035	$20	$61	$87	$190
2040	$23	$67	$93	$200

Q: Do the policies of the Ontario government inform the appropriate choice of a value of avoided carbon emissions?

A: Yes, in at least three ways. First, as noted above, the Government has established aggressive targets for reductions of carbon emissions, which implies a relatively high value of avoided emissions.

Second, the Ontario's Minister of Energy provided direction to the Ontario Power Authority (OPA) and electric utilities concerning inclusion of a placeholder value for "non-energy benefits" as follows:

[14]Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866; Interagency Working Group on Social Cost of Carbon, United States Government, May 2013, Revised July 2015. See http://www.epa.gov/climatechange/EPAactivities/economics/scc.html

> the OPA shall require that the benefits calculated for the Total Resource Cost Test include a 15 per cent adder to account for the non-energy benefits associated with Province-Wide CDM Programs and Local Distributor CDM Programs, such as environmental, economic and social benefits. The value attributed to non-energy benefits shall be subject to review at the formal mid-term review provided in section 6.1 of the March 2014 Direction. (Letter from Bob Chiarelli to Colin Andersen, RE: Amending March 31, 2014 Direction Regarding 2015–2020 Conservation First Framework, 23 October 2014)

Third, Ontario has aggressively pursued development of renewables to reduce carbon emissions. Ontario Power Generation has estimated that the implied CO_2 cost of Ontario's renewable investment was $1,000/tonne in recent years, falling to around $300/tonne after 2020.[15]

Q: How do the Ontario targets for carbon reductions compare to the emission reductions required by the U.S. Clean Power Plan?

A: The proposed Clean Power Plan would require a reduction in power-plant carbon emissions of about 17% from 2012 to 2030. Since power plants accounted for about 32% of 2013 US carbon emissions in 2012, the Clean Power Plan would require a reduction in jurisdictional emissions of about 5% by 2030.

The Ontario goals include reduction of jurisdictional emissions by about 26% from 2013 to 2030, or about five times the reductions expected from the Clean Power Plan.[16] Ontario's goals are more aggressive than those of the

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[15]Boland, Bruce. 2013. "Electricity Generation Optimization in a Period of Surplus Baseload Generation." Presentation, Carnegie Mellon School of Business, April 24, 2013, at 34.

[16]The US EPA expects additional emission reductions from additional programs, such as vehicle and gas-appliance efficiency standards, many of which would also be available to Ontario.

Clean Power Plan. That difference may increase the marginal cost of reaching those goals compared to that of the Clean Power Plan. While the Clean Power Plan relies heavily on renewables, efficiency, and gas backing out coal-fired generation, Ontario has already eliminated coal on its electric system. Additional reductions in Ontario carbon emissions will require such further measures as the following:

- backing down gas generation (which requires twice the load reduction per tonne avoided, compared to backing down coal),
- reducing usage of natural gas in buildings,
- reducing usage of oil in buildings,
- reducing industrial fuel use.

2. Extrapolating the 15% Electric Adder to Natural Gas DSM

Q: What is your understanding of the origin of the 15% adder for non-energy benefits of gas DSM?

A: The Minister of Energy ordered the use of the 15% adder for electric DSM, as I discuss in Section III.B.2. The Board then adopted that percent adder in the gas DSM framework.

Q: What was the Board's stated objective in adapting the 15% electric adder to gas?

A: In the Board's own words,

> To effectively align natural gas DSM programs with electricity CDM programs and take into consideration government objectives outlined in the Conservation Directive to the OPA, the Board has concluded that the same approach should be used for screening DSM programs. (Demand Side Management Framework for Natural Gas Distributors 2015-2020, Report of the Board, EB-2014-0134, December 22, 2014, at 33)

Unfortunately, applying a 15% adder to the avoided natural gas costs does not align the electric and gas programs, in terms of reflecting carbon prices, wholesale price mitigation, or most non-energy benefits of DSM.

Q: What implications for gas DSM might be drawn from the 15% placeholder adder for non-energy benefits prescribed by the Minister of Energy for electric DSM?

A: The Minister did not specify the breakdown of the 15% among carbon reductions, other environmental benefits, economic benefits and social benefits, nor the basis for selecting those values. As a result, the electric placeholder can be extrapolated to gas in several ways. One approach would be to assume that the 15% mostly represents carbon emissions (which the Government clearly considers to be very important), compute the dollars-per-tonne price equivalent to the 15% electric avoided-costs and convert that value to dollars per cubic metre.

Union's estimates of electric avoided costs average about $0.1186/kWh for 2016–2020; 15% of that value would be $0.0178/kWh or $17.79/MWh. The carbon emissions from the existing electric system would be almost entirely from gas-fired generation, which appears to be on the margin about 70% of the time in 2016–2020, with zero-carbon sources at the margin the remaining 30%.[17] Assuming carbon emissions of 53.1 kg per MMBtu of gas (1.5 kg/m^3) and a 9-MMBtu/MWh average gas-plant heat rate (averaging combined-cycle, combustion turbine and the Lennox steam plant), the

[17]Boland, Bruce. 2013. "Electricity Generation Optimization in a Period of Surplus Baseload Generation." Presentation, Carnegie Mellon School of Business, April 24, 2013, at 26–30.

\$17.79/MWh would be equivalent to \$53.19/tonne of CO_2. That carbon price is equivalent to about 10.3¢/m^3 of gas, or roughly 50% of the avoided supply cost.

Q: How would the extrapolation from the 15% placeholder adder for electricity to gas values vary were only half the 15% attributable to carbon?

A: In that case, the carbon value would be about \$26.6/tonne of CO_2 and about 5.1¢/m^3 of gas. In addition, the remaining \$8.9/MWh adder, on an equivalent energy value (about 94 m^3/MWh), would be about 9.5¢/m^3 and the total of environmental and non-energy benefits would be about 14.6¢/m^3. That would be about 65% of Union's avoided-cost estimates for 2016–2020.

Ontario is still finalizing its carbon-mitigation rules, but will require additional reductions before 2020. Given the demanding goals facing Ontario policy makers, it is reasonable to assume Ontario will implement carbon pricing by 2017 (about three years earlier than the schedule Synapse assumes for the U.S.). The utilities should immediately incorporate a carbon price in designing, screening, and budgeting their DSM programs.

Q: Why did you use energy content, rather than price, to convert the non-carbon portion of the electric placeholder to a gas equivalent?

A: Many of the non-energy benefits of DSM will vary with the amount of energy saved, rather than the cost of that energy, such as the following benefits:

- the improvement of comfort with reduced drafts and warmer interior walls;
- improvement of health by reducing condensation and mold;
- the benefits of employing workers to blow in insulation, seal gaps, wrap ducts, and replace windows.

C. *Avoidable and Average Cost of Gas*

Q: How would DSM load reductions affect rates to non-participants?

A: In principle, under economic dispatch, the utility sends out gas supplies to meet load in order of increasing cost. The DSM load decrement then would back out the most expensive supplies and avoided gas costs would exceed average.[18] As a result, DSM would reduce the average cost of commodity, and thereby benefit all customers, including non-participants.

Since it is likely that the Companies' have understated avoided gas commodity cost, any improvement in their analyses would increase the estimate of system net benefits.

Q.: Have you done a comparison of avoided supply costs with average rates?

A: Yes. I was able to make this comparison for residential and commercial customers, since both Companies provided a breakdown of their avoided costs into supply, transportation and storage. (See EB-2015-0049, Exh. I.T9.EGDI.GEC.43(a) and Exhibit JT2.7, Attachment 1.)

Q: In the case of Enbridge, what was the result of your comparison?

A: Enbridge's commodity price in the most recent four quarters has been on average $0.163/m^3.[19] Enbridge estimated 2016 avoided supply costs for weather-sensitive loads to be significantly greater; see Table 5 below.[20]

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[18]It is possible that there are some embedded resources with minimum take provisions that interfere with economic sendout. However, over long run, the utility should be able to optimize its contracts.

[19]http://www.ontarioenergyboard.ca/oeb/Consumers/Natural Gas/Natural Gas Rates/Natural Gas Rates—Historical

[20]I used the avoided cost estimate for 2016 because the estimate for 2015 is out of line with the 2016 through 2044 cost trend. In both 2013 and 2015 analyses, there is a big 30% jump in

Table 5: Avoided Commodity Cost in 2016 (Dollars per Cubic Metre)[21]

Year of Avoided Cost Estimate	Water Heating (baseload)	Space Heating (weather-sensitive)	Water and Space Heating (weather-sensitive)
2013[a]	0.1810	0.1972	0.1947
2015[b]	0.1617	0.1762	0.1738

[a] Exhibit I.T9.EGDI.GEC.43(a).
[b] 2013 avoided costs adjusted by the reduction in total avoided costs.

A comparison of avoided and average supply costs indicates that for every cubic metre saved by a weather-sensitive measure, there is about a \$0.01 reduction in total commodity costs.

Q: Did the comparison have a similar result in the case of Union Gas?

A: Yes. As seen in the following table, the comparison with Union's 2016 avoided cost also shows about a \$0.01 reduction in total commodity costs for every m^3 saved; the comparison with 2015 avoided cost is even higher. In addition, for Union, unlike for Enbridge, baseload measures produce almost as much savings as weather-sensitive measures.

avoided cost from 2015 to 2016, but the cause of this anomaly is not explained in any of Enbridge's documentation.

[21]It is my understanding that the change between Enbridge's 2013 and 2015 avoided cost estimates reflects a change in the avoided supply cost estimate only. Therefore, I derived avoided commodity costs consistent with Enbridge's 2015 update by applying the reduction in total avoided costs to the 2013 avoided supply costs.

Table 6: Union Avoided versus Average Commodity Charge
(Dollars per Cubic Metre)

	Avoided Commodity Cost		Avoided Minus Average Commodity[a]	
	Res/Com Baseload	Res/Com Weather-Sensitive	Res/Com Baseload	Res/Com Weather-Sensitive
2015	0.173	0.176	0.022	0.025
2016	0.159	0.161	0.007	0.009

[a]Assumes $0.151/m^3 commodity rate

Q: What is the significance of the differentials you discuss above?

A: Unlike the other components I discuss in this section, these differentials between avoided commodity costs and average commodity costs are included in the utilities' avoided costs (although they appear to be understated). The significance of the avoided-to-average differentials is that they should be reflected as benefits to non-participants in the assessment of rate effects.

D. Avoided Distribution Costs

Q: How do the utilities estimate avoided distribution costs?

A: Enbridge provided some cost and load data to its consultant, Navigant, which converted those values to an estimate of avoided distribution costs. Union manipulated the Enbridge estimate of avoided distribution costs to derive an estimate of its avoided distribution costs.

Q: Do the utilities' avoided costs include their local transmission costs, or only distribution?

A: That is not clear.[22] The distinction between transmission and distribution mains varies from one document or application to another. In general,

[22]Obviously, no Union transmission costs are directly reflected in its avoided costs, since it used only Enbridge results.

Enbridge and Union appear to define "transmission" to mean "for wholesale transactions" and "distribution" to mean "for our retail customers." Hence, a single line can be considered to be partially transmission and partially distribution.

Enbridge claims that "transmission, or upstream, avoided costs, such as commodity, transportation and storage costs, were fully captured in the existing avoided gas cost methodology" (Exhibit I.T9.EGDI.GEC.33a), and considers the costs included in Exhibit C, Tab 1, Schedule 4 to be distribution costs.

Enbridge's consultant Navigant entitled its report "Enbridge Avoided Transmission & Distribution Costs," but says,

> During the initial discovery stage of this assignment it was determined that Enbridge's upstream or transmission avoided costs are already fully and accurately captured in their existing avoided cost analysis. The objective was subsequently modified from a study of both transmission and distribution avoided costs to only include the determination of the distribution or downstream avoided costs." (Enbridge Exhibit C, Tab 1, Schedule 4, at 4).[23]

In its presentation for the first workshop with Enbridge, Navigant reviews the avoided costs of a few gas utilities and finds that only one includes capacity as avoidable (Exhibit JT1.23, Attachment 1). In its presentation for the second workshop, Navigant asserts that "Enbridge's existing avoided cost calculation methodology (using Sendout) captures all upstream costs" (Exhibit JT1.23, Attachment 2, at 4). As I discuss in Section III.E.1, Enbridge has not provided on discovery any documentation that

[23]Enbridge has not provided the basis for that "determination," nor any breakout of the avoidable upstream transmission costs.

would have allowed Navigant to reach this conclusion, even though such documentation was requested in GEC 49 and Undertaking 1.23.

Union refers to its reworking of Enbridge's estimate of avoided distribution costs as avoided T&D or infrastructure costs, but makes no effort to include avoided transmission infrastructure.

1. Enbridge

Q: How did Navigant estimate Enbridge's avoided distribution costs?

A: Navigant indicates that Enbridge "provided Navigant with both actual and forecast reinforcement expenditures" (Enbridge Exhibit C, Tab 1, Schedule 4, at 19) for 2010–2019, totalling $189 million (ibid., Figure 3). While Figure 3 does not specify whether the costs are in nominal, real, or a mix of costs, Navigant reports an average of $19 million annually over the ten years in 2015 dollars (ibid. at 20).[24]

Navigant also reports average annual growth in design-day peak for 2010–2019 of 1,047 10^3m^3 (ibid., Figure 4). That would imply a distribution investment of \$18,050/10^3m^3 of load growth. Oddly, Navigant never reports this critical value.

Navigant annualizes the \$18,050/10^3m^3 using an idiosyncratic approach, which is described generally at 22–26 of the report, in a section entitled "Detailed Methodology." Unfortunately, Navigant does not provide the details of its computations or even the results in dollars/year per 10^3m^3 of peak load reduction. Backing out the annual cost from the \$/10^3m^3 values in Table 7 of the report and the peak-to-annual ratios in Table 9 results in an

[24]Enbridge has not provided the underlying data, so we cannot check whether all the costs were actually in 2015 dollars.

annual peak cost of about \$1,070/10^3m^3 of peak-day load. In turn, that value indicates that Navigant effectively applied a 5.9% nominal carrying charge to the investment.

Finally, Navigant converts its estimate of avoided distribution costs to dollars per 10^3m^3 of avoided deliveries (over the year, not on the peak day), using the ratios of peak-day 10^3m^3 to annual 10^3m^3 in Table 9 of the report. These values are reported in Table 7, labeled as nominal dollars per 10^3m^3/peak demand day, even though the values are clearly intended to be costs per annual 10^3m^3.[25]

Thus, Enbridge's estimate of avoided distribution comprises the following six steps:[26]

1. Compile load-related investments over a decade.
2. Determine expected design-day peak over that same period.
3. Divide (1) by (2) to estimate the required investment per 10^3m^3 of peak growth.
4. Multiply (3) by a carrying charge to estimate annual avoided cost per 10^3m^3 of peak growth.
5. Estimate the ratio of design-day peak load contribution to annual consumption by rate class.

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[25]Errors of this sort, along with inconsistencies in Enbridge's responses and Enbridge's failure to provide data, make reviewing Enbridge's work very difficult. Enbridge refused to provide its analyses, computations and workpapers supporting the derivation of the avoided distribution costs (e.g., Exhibit I.T9.EGDI.GEC.49, 59).

[26]Some of the steps were conducted by Enbridge and some by Navigant. For simplicity, I will refer to the derivation of avoided distribution costs as Enbridge's method.

6. Multiply (4) by (5) to estimate avoided cost per $10^3 m^3$ of reduced throughput.

These are all standard steps in estimating avoided distribution (and often transmission) costs.

Q: Did Enbridge properly carry out this analysis?

A: No. Enbridge appears to have made mistakes in steps 1, 2, 4, and 5 (load-related distribution investment, associated load growth, the carrying charge, and the load shape). In addition, Enbridge omitted all load-related distribution O&M costs. I will comment on each of these problems in turn.

a) Load-related Distribution Investment

Q: Did Enbridge include all its load-related investments in the 2010–2019 period?

A: No. Enbridge acknowledged omitting some cost categories, its two tabulations of projects in the attachments to Exhibit I.T9.EGDI.GEC.56 are inconsistent, and it has clearly understated the costs of the GTA project.

Q: Which cost categories did Enbridge acknowledge omitting?

A: Enbridge acknowledged omissions in its identification of distribution reinforcement projects (Exhibit I.T9.EGDI.GEC.56 and 57).

> The reinforcement expenditures for Area 10 and Appendix B were inadvertently omitted from the information provided to Navigant. In addition, an equation error was made in the spreadsheet that was used by Enbridge to provide the reinforcement expenditures to Navigant that double counted the years from 2010 to 2012.
>
> The reinforcement projects in Area 10 are those that were listed in … Exhibit I.T9.EGDI.GEC.57. The reinforcement projects in Appendix B are those that can be found in…Exhibit I.T9.EGDI.GEC.56. (Undertaking JT1.28)

The reinforcement projects in Area 10 (the GTA) in Exhibit I.T9.EGDI.GEC.57 for 2017–2019 were listed in the GTA proceeding (EB-2012-0451) as having cost estimates totaling $50.4 million.[27] The Appendix B projects in Exhibit I.T9.EGDI.GEC.56 are listed at $5.9 million. Enbridge reports that these two categories would total "approximately $55M," which may or may not be consistent with the values reported in the GTA proceeding and Exhibit I.T9.EGDI.GEC.56, depending on the dollars in which each estimate is stated. The cost estimates of the GTA proceeding may have been updated since they were filed in 2012.

Q: What are the inconsistencies between the tabulations of reinforcement projects in Attachment 1 and Attachment 2 of Exhibit I.T9.EGDI.GEC.56?

A: Attachment 1 does not have most pre-2014 projects, since it is a response to a request for forecast additions. From 2014 through 2019, Attachment 1 (the list of projects included in the forecast reinforcement expenditures from 2014 to 2019 in the Navigant analysis) lists some 44 projects, while Attachment 2 (the list of the projects included in the Navigant analysis) lists some 32 projects.[28] 21 projects appear in both lists, while Attachment 1 has 23 projects that do not appear in Attachment 2, and Attachment 2 has 11 projects

[27]It is not clear in what year's dollars these estimates, or any of Enbridge's cost estimates for future projects, are listed.

[28]The Attachment 1 is listed as Table 13 to 21 and Appendix B of some unidentified document, which appears to be the "EGDI planning document from which the forecast reinforcement expenditures from 2014 to 2019 were taken," as requested in GEC interrogatory 56. If Enbridge had provided the entire requested document, some of the discrepancies in its analyses might be easier to reconcile.

that are not listed in Attachment 1. Some of these discrepancies may result from the renaming of projects, and Enbridge says that three of the Attachment 1 projects not listed in Attachment 2 have minimal costs, but it still appears that neither list was complete. Unfortunately, Enbridge has not revealed what projects it included in the data provided to Navigant.

Strangely, while Attachment 2 lists the GTA project in 2015, Attachment 1 does not list the GTA at all.

Q: Are there other inconsistencies in the Enbridge data on capital additions?

A: Yes. In the Asset Plan filed in its last rate case (EB-2012-0459, Exhibit B2, Tab 10, p 53), Enbridge reports reinforcements much higher than those in Figure 3 of the Navigant report. See Table 7.

Table 7: Comparison of Reported Historical Reinforcements

	Navigant Figure 3	2012 Asset Plan
2010	$1.67	$7.05
2011	$1.58	$4.74
2012	$8.71	$15.47

Since the Navigant data appear to be in real 2015 dollars and the Asset Plan is in nominal dollars, the Asset Plan's costs would be a little higher restated in the terms of the Navigant report. It is not clear how the mains reinforcements in 2010–2012 could have declined in the past couple of years.[29]

[29]The Asset Plan also projected 2018–2019 additions about $55 million higher than reported for those years in Navigant's Figure 3.

Q: What GTA costs should have been included in the list of reinforcements?

A: The GTA project consisted of Segment A, which Enbridge classified as 40% related to serving distribution load and 60% related to serving wholesale transmission load, and Segment B, which Enbridge classified as entirely related to distribution load (Exhibit I.T9.EGDI.GEC.52). The investments classified as distribution are all load-related reinforcements.[30] Enbridge excluded some of the costs of the GTA distribution investments from the analysis:

> Reinforcement costs for larger projects such as the GTA Project were adjusted to reflect the proportion of the project costs that were directly attributable to load growth. The reinforcement costs of the GTA Project were captured in the costs shown in year 2015 in EB-2015-0049 Exhibit C, Tab 1, Schedule 4, Figure 3. (Exhibit I.T9.EGDI.GEC.33b)

> The reinforcement costs as shown in Figure 3 include the Ottawa Reinforcement and the GTA Reinforcement costs. Since these projects had multiple drivers, only the costs associated with load growth were included. (Exhibit I.T9.EGDI.GEC.56d)

In Exhibit JT1.17, Enbridge justifies those exclusions as follows:

> [The] minimum pipe [for the GTA] required a NPS 36 build from Sheppard Avenue to McNicoll Avenue, paralleling the existing Don Valley line, to support 10 years of anticipated load growth. This pipeline segment was estimated to cost $40M to $50M.

[30]One justification for Segment B was reducing pressure on part of the system; load growth had already exceeded the level at which Enbridge could serve all load at the lower pressure that Enbridge considered prudent. Lower load growth in the GTA would have avoided the need for Segment B.

> For the Ottawa Reinforcement Project, it was estimated that 19 km of NPS 16 would be required from Richmond Gate Station, including a rebuild of the gate station, to support load growth only. This project scope was estimated to cost $46M. It should be noted that this is the same alignment as the approved reinforcement project.[31]

The distribution portions of the GTA project (adjusting proportionately the costs provided in the GTA proceeding for each segment by the increase in the total project cost reported in EB-2015-0122, Exhibit D.1.2) are roughly as follows:

- $400 million for Segment A (justified primarily to import additional US gas, and hence more properly a supply cost),
- $200 million for Segment B1,
- $125 million for Segment B2.

These are large investments compared to the $189 million that Enbridge included as the load-related costs for the entire ten-year period.

Q: Are there other categories of load-related investment costs that Enbridge excluded from its analysis?

A: Potentially. Enbridge excluded all "sales" projects, related to the connection of new loads, and all replacement and relocation projects. Both of these categories may contain load-related costs. In particular, the sales projects would provide some of the capacity required for new customers, and the size of new mains may be a function of the efficiency of the new customers, and possibly existing customers served by the same lines. Similarly, the size of replacement mains can be affected by load levels, and replacement of a small

[31]Enbridge does not specify what purpose the Ottawa Reinforcement met, other than meeting demand.

old main with a larger-diameter smooth main can increase the capacity of the line.

Alternatively, the increases in capacity associated with sales, replacement and relocation projects can be reflected by adjusted downward the load growth served by the reinforcement projects, as I discuss in the next subsection.

b) Design-peak Load Growth, 2010–2019

Q: Have you been able to review the data on design-day peak growth that Navigant presents in its Figure 4?

A: No. However, even if the data reflect weather-adjusted peaks for 2010 and Enbridge's forecast for 2019 (the intervening loads do not affect the computation), the peak growth should be adjusted down to reflect the part of the growth that is accommodated by sales projects and upgrades of replacement mains. The cost of reinforcements should be divided by the growth requiring the reinforcements, excluding any growth accommodated by other projects. The lower the growth divisor, the higher the ratio of investment per unit of peak load.

For example, the Municipality of York Pipeline Project (EB-2011-0270) replaced an NPS 4 and an NPS 8 line with an NPS 12 main along the same route, more than doubling the capacity of that section of the system. While the replacement was triggered by a relocation request from the municipality, the update would serve any increase of load in that demand area (Whitchurch-Stouffville and Uxbridge). The load increases that drive the need for reinforcements would be net of the load increases in the Whitchurch-Stouffville and Uxbridge areas, and all other areas in which growth was served by sales, replacement and relocation projects.

c) Annalizing the Avoided Distribution Cost

Q: How does Navigant annualize the avoided distribution costs?

A: Navigant uses a nominal 5.9% carrying charge for the distribution investments, which it does not document. In contrast, I estimate a *real-levelized* carrying charge of about 6%. I used a standard computation of the real-levelized or economic carrying charge, which measures the present-value benefits of a one-year delay in the investment, with the benefit rising at inflation in subsequent years.[32] I suspect that Navigant became confused between real and nominal carrying-charge computations.[33] I cannot test that, since Enbridge has not provided Navigant's workpapers.

A 6% real-levelized carrying charge is equivalent to a nominally levelized carrying charge of about 7.7%. The real-levelized discount rate provides meaningful avoided costs for any period, while the nominally levelized carrying charge is only meaningful for the period over which it is levelized. While the benefit of deferring investments rises as the investments are pushed further back (due to inflation), Navigant somehow concludes that avoided distribution costs would fall over time.

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[32] I used the inputs specified by Navigant in its Table 8, a 2% inflation rate, and a 7% discount rate, based on assumptions elsewhere in Enbridge's filing.

[33] It is possible that Navigant intended that its carrying charge be applied in real terms, but accidentally treated the charge as nominal.

d) Converting from Peak Day to Normal Average Usage

Q: Did Navigant properly apply the load data to convert the avoided T&D in annual dollars per cubic metre on the design day to dollars per cubic metre of annual consumption for each load shape?

A: Navigant did not provide the design-day peak, normal-year peak, annual consumption, or any other data on the load shapes they used. However, Navigant describes the data it used as follows:

> calculated avoided cost in terms of annual DSM volumes saved instead of peak day demand gas savings. This is done by using Enbridge's existing DSM load shape profiles using the peak day demand to annual volume ratio. (Enbridge Exhibit C, Tab 1, Schedule 4, at 6)

> Daily gas consumption for each load shape is gathered. The total annual consumption for the year is calculated and the gas consumption for the peak day demand (January 15) is determined. The consumption for the peak day demand is divided by the total annual consumption. The ratio for each of the four DSM load shapes is used to convert the peak day demand distribution avoided cost ($\$/10^3m^3$ annual peak day demand) to a volumetric avoided cost. (Ibid. at 26–27)

Appendix B to the Navigant study shows graphs of the load shapes that Navigant used. While it is not entirely clear, these seem to be normal load shapes, without any allowance for design conditions.

Q: What is the significance of using normal peak loads instead of design peak?

A: Since design peak is higher than normal peak, each thousand m^3 of annual savings results in greater savings on the design peak than on the normal peak. The distribution system is designed for the design-peak day (or the design-peak hour), while DSM savings are computed for the average year, so the avoided distribution costs should reflect the ratio of design peak to normal average usage.

e) Operating and Maintenance Costs

Q: Are any avoided O&M costs reflected in Enbridge's estimate of avoided distribution costs?

A: No. Navigant's report (Exhibit C, Tab 1, Schedule 4) assumes that no distribution O&M costs are avoidable.[34]

Q: Is this a reasonable assumption?

A: No. Enbridge's GTA application, for example, reports an incremental O&M of over $13 million for such costs as "leak survey, damage prevention, cathodic protection, [and] direct maintenance." (EB-2012-0451 Exhibit E Tab 1 Schedule 1, at 2, updated: 2013-06-03) That is 1.5% to 2% of the project cost (depending on the costs included in the analysis); those costs would increase over time with inflation.

In its third workshop presentation, Navigant corrected its earlier methodology by (among other things), adding avoided annual O&M of 1% of the avoided investment (EB-2015-0049, Exhibit JT1.23, Attachment 3, at 6).

Since the real-levelized carrying charge for distribution is only about 6%, O&M of 1%–2% would add something like 20% to 30% to the carrying charges for the distribution projects.

[34] In Exhibit I.T9.EGDI.GEC.59(b), Enbridge claimed that reductions in O&M for avoided reinforcements should be ignored because its O&M budgeting process does not consider the effect of reinforcements installed or deferred. This claim does not justify omitting O&M from avoided cost for two reasons. First, since O&M costs do vary with the amount of distribution, the effect of deferrals will eventually appear in the O&M budget. Second, avoided cost should reflect actual costs, not budgets. Budgets should be viewed only as a source of estimates of actual costs.

f) Summary of Enbridge Corrections

Q: What is the cumulative effect of correcting Enbridge's apparent understatements in its estimate of avoided distribution costs?

A: In Table 8, I combine rough estimates for the effects of the errors I discuss above. Specifically, I account for the following:

- the projects that Enbridge acknowledges having failed to share with Navigant,
- the unexplained downward revisions in 2010–2012 additions,
- the full estimated costs of Segment B2 of the GTA,
- the cost of Segment B1 of the GTA (as a sensitivity),
- a 20% reduction in load growth associated with the reinforcements, to reflect the capacity upgrades from sales-related, replacement, and GTA projects. For the sensitivity in which Segment B1 is treated as directly load-related, I use a 10% adjustment for load growth met by the other categories.
- correction of the nominal carrying charge to 7.7% (equivalent to a 6% real carrying charge),
- An allowance for O&M of 1% of investment.

I do not have enough data to correct the load-shape ratios, from normal weather to design weather.

Table 8: Corrections to the Enbridge Estimate of Avoided Distribution Cost

	10-yr Additions 2015$ M	10-yr Growth 103m3	Additions per Unit Growth $/103m3	Carrying Charge Nominal	Annualized $/yr/103m3 peak day	O&M $/yr/103m3 peak day	Total $/yr/103m3 peak day
Enbridge	$189	10,470	$18,052	5.9%	$1,065		$1,065
Corrections							
Area 10	$50.4						
Appendix B	$5.9						
2010-12 revisions	$17.4						
GTA Segment B2	$85	−20%					

GTA Segment B1	$200	−10%					
Corrected							
without B1	$348	8,376	$41,508	7.7%	$3,196	$415	$3,611
with B1	$548	9,423	$58,121	7.7%	$4,475	$581	$5,057

The corrected nominally-levelized values are about 3.4 to 4.7 times the Enbridge estimate. In real-levelized terms, the total costs would be about $2,900–$4,100/yr/10^3m^3 of peak-day throughput, or 2.7–3.8 times Enbridge's nominally-levelized estimate in 2015, and would rise with inflation.

Q: Did Navigant develop higher estimates of avoided distribution costs than those presented in Enbridge's filing?

A: Yes. In its second workshop for Enbridge, Navigant reported an avoided distribution cost of $1,165/$10^3$m^3 savings on the peak day (Exhibit JT1.23, Attachment 2, at 11).[35] In its third workshop presentation, Navigant reported an avoided distribution cost of $1,523/$10^3$m^3 savings on the peak day (Exhibit JT1.23, Attachment 3, at 6). These values are about 10% and 40% higher than the $1,065/$10^3$m^3 reported by Navigant in Exhibit C, Tab 1, Schedule 4 and apparently used by Enbridge in screening DSM programs.

2. Union

Q: How did Union estimate its avoided distribution costs?

A: Union did not develop T&D avoided costs based on its own system, but borrowed the work from Navigant based on Enbridge's system and adapted them for its use. Specifically, Union took the Enbridge estimates of avoided distribution costs by load shape, weighted those values by the share of Union's estimated DSM savings in 2015 for each of the load shapes, and

[35] Navigant does not appear to have used design-day loads in its analyses.

derived a distribution adder of 2% (Union Exhibit A, Tab 1, Appendix D, at 3, footnote 1), which it applied to all DSM.

Q: Is this computation appropriate?

A: No. The avoided distribution costs vary among the load shapes because a given annual load reduction of heating DSM saves much more gas on the design peak than the same reduction in base load. Union estimates that Enbridge's estimate of avoided distribution costs average 4.3% of Enbridge's estimates of avoided supply costs for space heating and 1.3% for water heating and baseload, over 30 years.

At the very least, Union should have used Enbridge's percentages or dollars per cubic metre for each load shape. The 2% value was computed by weighting industrial savings 85.5%, water-heating 3.2%, and space-heating only 11.3%. Assuming that savings for some period of time will include much lower industrial savings, the average avoided distribution adder would be closer to the space-heating 4.3% than to Union's 2%.

Correcting the errors and understatements in Enbridge's avoided-distribution estimates would produce an even larger average adder, on the order of 12% to 20%. In any case, Union should be using separate $\$/m^3$ values for each load shape, rather than an average value or percentage adders.

Q: Has Union provided any estimates of avoided distribution costs?

A: Yes. In Exhibit JT2.5, Attachment 1, at 75, Union provides an estimate developed in 1998. It is $\$30.64/m^3$ of design-hour load, or about $\$1.53/m^3$ of design-day load. Including inflation to 2015, this value would be $\$2,153/10^3m^3$ of design-day load, about twice the value that Enbridge used in this proceeding. The results of the older Union study would bring the avoided distribution cost to about $0.024/m^3 of space-heat load saved, or about 11% of Union's estimate of avoided supply costs.

E. Utility Refusal to Allow Review of Avoided Cost

Q: Have the Companies provided adequate documentation of the avoided cost analysis?

A: No. Neither of the Companies provided the documentation (including inputs, calculations and workpapers) necessary to allow full independent review of their avoided costs.

Q: Why is access to this documentation essential to review?

A: When data, calculations, model inputs and outputs, and electronic spreadsheets are provided, intervenors are able to check the utility's calculations for errors or omissions, weigh in on the judgments on which experts may reasonably disagree, confirm their understanding of methodologies, and gauge the effect of alternative inputs and assumptions on the results. Without this information, avoided cost numbers cannot be evaluated or independently verified. As can be seen from the discussion above of the distribution component of avoidable costs and the numerous errors I was able to identify with only limited access to information, such errors or controversial methodological choices are not unusual and not insignificant.

1. Enbridge

Q: What is the basis for the Enbridge's refusal to provide adequate documentation of its avoided costs?

A: Enbridge provides a number of reasons, but its underlying position is that the DSM planning process in Ontario permits it to select the avoided costs without outside scrutiny. In particular, it asserts that the current avoided costs on which the DSM Plan relies are not relevant because Enbridge will be updating them at the end of 2015 (Tr. 8/6/15 at 99). With each change in avoided costs, of course, Enbridge has broad latitude to change the DSM portfolio without Board or third party review.

Q: Why is it important to examine the avoided costs in a DSM plan proceeding?

A: Avoided costs are an essential component of the development of a cost-effective DSM plan and the assessment of impacts on non-participants.

Q: What other reasons does Enbridge give for refusing to document its analysis?

A: Enbridge makes the following assertions:

- As long as it uses a previously accepted methodology, there is no need for independent review in this proceeding:

> This proceeding is not about considering changes to the methodologies which have been approved and revised over the last 20 years in respect to the company's gas supply plan, because it would involve not only Enbridge but also Union Gas. We could be at this for months. (Tr. 8/6/15 at 77)

The Company further states,

> we don't necessarily agree that providing [the commodity price forecast] is going to be of any benefit to the Board in this proceeding. We relied upon the forecasts for the purposes of developing the various plan outcomes.
>
> That's the process and we don't believe, as I have indicated before, that issues related to avoided costs, to the specificity that you are suggesting, is relevant for the purposes of this proceeding. (Tr. 8/6/15 at 94–95)

> Our position is that the processes that have been followed for the purposes of developing Enbridge's, and presumably Union's, plan in this proceeding have been done in accordance with the currently approved methodology and protocols, and that this proceeding is not going to be looking into whether or not those protocols should be changed strictly for DSM purposes. (Tr. 8/6/15 at 96)

- Even where it relies on a methodology that has not been previously approved, the Company is not expected to make the analysis accessible to intervenors for review:

> …I just believe it is beyond the expectation of the Board in this proceeding that we get down into matters of this nature and this detail for the purposes of this DSM proceeding. So I just don't believe it is an appropriate production. (Tr. 8/6/15 at 113)

> So I think, while [the avoided distribution cost analysis] is not necessarily approved methodology yet, this particular study, it certainly is a best effort to address this topic in a way that is directionally helpful for the preparation of the DSM plan. (Tr. 8/6/15 at 114)

- Performing "reasonable scenarios as requested" is a suitable alternative to providing the inputs and outputs used to calculate avoided costs (Exh. I.T9.EGDI.GEC.30(j)).
- The documentation is proprietary. In the case of Enbridge's use of the PIRA gas price forecast, the Company claimed that it is "bound by contract to not publicly disclose the document, and that includes the parties to this proceeding" (Tr. 8/6/15 at 92, 93).
- Allowing intervenors access to models creates regulatory inefficiency. In particular, in the case of the avoided distribution cost analysis,

> to the extent that then there is another run that's made of the model and it generates some different results, it becomes very difficult, if not impossible, for other parties and the Board to understand exactly what's been done, and you often then spend a great deal of time trying to simply recreate what steps were undertaken to generate the different results. I'm not exactly sure what you're intending on doing with the model, but that is one concern. (Tr. 8/6/15 at 112)

Q: Is Enbridge correct that when it uses the previously approved methodology, there is no need for examination of its analysis?

A: No. What Enbridge refers to as the "approved methodology" is only a general framework for analysis. Enbridge's description of this methodology (in EB-2012-0394, Exhibit B, Tab 2, Schedule 2) is limited to the following documentation:

- an explanation that avoided gas costs are determined based on the difference between two runs of a resource dispatch model, called SEND-OUT, with and without DSM.
- A list of some of the key inputs, including charges for gas supply (e.g., monthly gas prices at Henry Hub, gas price differentials at the various supply points, seasonal gas price adjustment factors, and transportation and storage contract demand and variable costs) and DSM decrement load shapes.

Enbridge's description of the methodology did not provide the actual values input to the SENDOUT model or the derivation of those values. And the Board's approval of a framework for analysis does not imply approval of inputs that the Board never reviewed.

Enbridge's position that using an approved methodology obviates the need for outside review is tantamount to asserting that there is no need to review a utility's rate request when it is following Generally Accepted Accounting Practices.

Q: Does Enbridge's description of its use of the SENDOUT model cover all input assumptions?

A: No. There are many user options available in the SENDOUT model that Enbridge does not even describe, let alone document. As described by the model vendor ABB, the SENDOUT model has two basic modules, Standard Optimization and Resource Mix Optimization. Under Standard Optimization, the model optimizes the system sendout given a fixed set of supply, transportation and storage resources. The resulting avoided costs reflect only variable costs. This analysis can be made to assume that the contract demand charges cannot be avoided. Under the second module, the model seeks the least cost supply portfolio and the resulting avoided costs include contract demand charges. Appendix B is a brochure from ABB that shows the interface that gives the user the option of specifying the type of capacity release; that release option may be in addition to options for not renewing or expanding capacity.

There are additional user inputs that determine whether the DSM decrement will avoid the most expensive supplies or reduce upstream pipeline and storage capacity costs.

Q: Please provide some examples of these SENDOUT model user options.

A: The SENDOUT model allows the user to model the following actions:

- release pipeline and storage capacity to the market, either for the short-term or long-term;[36]
- permit or limit off-system sales transactions;
- allow renegotiation of contracts;
- establish rules governing the acquisition of pipeline or storage capacity to meet load growth;
- set constraints on the use of supply resources, such as minimum-take provisions;
- establish the planning reserve margin;
- set limits on reliance on spot gas.

Q: Would you provide some examples of how inputs affect avoided costs?

A: Yes. Inputs could affect avoided costs in the following ways:

- If capacity is assumed fixed, capacity release allows the utility to reduce its excess capacity costs in response to a reduction in load.
- Minimum-take provisions may interfere with economic dispatch by requiring that a more expensive supply be sent out to meet demand before a cheaper one.
- If pipeline contract capacity could be renegotiated in response to a DSM load reduction, the foregone pipeline capacity cost would be reflected in avoided cost.

[36] In its 1997 avoided-cost analysis, Union modeled the avoided cost of storage as "the opportunity cost associated with storage release to M12 customers." Exhibit JT2.5, Attachment 1, at 66.

Q: In other jurisdictions, have regulators found it important that intervenors understand the utility's use of the SENDOUT model?

A: Yes. In the review of Questar's 2011 IRP, the Public Service Commission of Utah stressed the importance of having parties understand the model:

> We recognize the challenges faced by parties in understanding all of the intricacies of the SENDOUT modeling processes for acquisition of both short- and long-term resources. In general, we conclude a knowledge gap exists regarding how cost-of-service gas is incorporated into and evaluated by the model, both in the short and long run. We find the details associated with Questar's IRP modeling warrant clarification and further discussion. We encourage the parties to meet with the goal of enhancing understanding of the SENDOUT model, including its setup, logic, and constraints.

and

> At the present time we find greater value in ensuring parties have a solid understanding of the SENDOUT model logic and decision rules rather than directing the Company to hire an outside expert to perform an examination of the model.

Q: Will Enbridge's proposal to run alternative scenarios provide an adequate substitute for intervenor access to the Company's data, calculations, and models?

A: No. Relying on Enbridge to run scenarios with alternative inputs is not an adequate solution, for the following reasons:

- Since Enbridge has not specified its actual inputs or user options, it is not even possible to develop alternative assumptions.
- The discovery process creates long lead times between intervenor requests for modifications and receipt of spreadsheet results, thereby limiting development of alternative designs.
- It would not be possible to make sure that the Company correctly understood and made the desired modifications.

- If the results seem counter-intuitive or incorrect, intervenors would not be able to check the inputs and model output for a possible explanation.

Q: Is it clear that the PIRA price forecast cannot be made available to intervenors under a confidentiality agreement?

A: No. In the Technical Conference, Enbridge acknowledged that it "would have to check the contact" but "would consider and respond to any order that the Board issues, to the extent that we are required to by law" (Tr. 8/6/15 at 94).

Q: In your experience, do utilities generally give intervenors access to commodity price forecasts?

A: Yes. In other jurisdictions, utilities routinely provide commodity price forecasts (their internal forecasts and projections from consultants) under confidentiality agreements.

Q: Does Enbridge's concern about regulatory efficiency justify its refusal to provide calculations and models?

A: No. Failure to provide essential information impedes the regulatory process; it does not increase its efficiency.

Q: Is Enbridge correct that the avoided distribution cost analysis is too complex to be reviewed in this proceeding?

A: No. From Navigant's description of the analysis, it appears to consist of cost and load data, assumptions and arithmetic formulas. Any change by intervenors to the assumptions or calculations would be straightforward to document, reproduce and evaluate.[37]

2. Union

Q: Did Union Gas also make a blanket refusal to document its avoided costs?

A: No. Union Gas provided enough documentation to permit some external review of its analysis. Union did refuse to provide the inputs and outputs of its dispatch model runs, but not because of some fundamental objection to avoided cost review:

> Union will not provide the output of the SENDOUT model. The output of the SENDOUT model totals approximately 42,000 lines of information, which is used for Union's annual Gas Supply Planning process. EB-2015-0029 Exhibit JT2.11

Q: Do you agree that the spreadsheet with 42,000 lines of data is too large to be provided to intervenors?

A: No. Just one sheet of an Excel workbook can contain more than 42,000 lines. Since the output is likely to be a file that contains labels and numbers, and no formulas, the SENDOUT output should be much smaller than other files provided to intervenors in this proceeding.[38]

[37]The Company also claimed in Exhibit I.T9.EGDI.GEC.50 that Navigant's avoided distribution cost workpapers are confidential and cannot be provided to intervenors. Since the analysis appears to be essentially arithmetic, Enbridge's refusal to provide access to these calculations does not seem well founded.

[38]In particular, Union's responses to discovery included an 88 MB PDF file and four 35 MB Excel files, at least one of which contains 55,000 rows of data (B.T6.Union.GEC.4 Excel Attachment 3).

Furthermore, it is likely to be in a format easily produced by Union and accessible to outside reviewers, since according to ABB, the model vendor, SENDOUT provides "customizable reports/graphs and seamless integration to Microsoft Excel" (ABB materials, attached as Appendix B, at 3).

Q: Have you been able to obtain an example of output from the SENDOUT model?

A: Yes. In Massachusetts, National Grid provided outputs from its SENDOUT model runs as part of the investigation of its request for approval of a firm transportation contract (D.P.U. 13-157, Attachment RR-DPU-3). I have included the output from one of the National Grid runs as Appendix C.

F. Avoided Supply

1. Enbridge

Q: What problems have you identified in Enbridge's avoided gas-commodity-cost analysis?

A: Without knowing the actual monthly gas price forecasts Enbridge used, there is not much I can say. However, I have identified two ways in which Enbridge understated avoided commodity costs:

- After the first ten years of the forecast (from 2025 onward), Enbridge assumed that the cost of gas will increase only with the rate of inflation, or, in other words, will remain constant in real terms (EB-2015-0049 Exhibit I.T9.EGDI.GEC.29(a)).
- Enbridge based its avoided gas costs on monthly price projections, thereby ignoring the effect of daily price variability, the tendency of high loads to coincide with high prices, and the costs of dispatching storage to accommodate changes in load from day to day.

Q: Did Enbridge acknowledge that its assumption that gas prices would rise only with inflation can understate avoided supply costs?

A: Yes. Enbridge stated that it will consider using a longer-term gas price forecast, rather than a simple inflation adjustment, in future avoided cost analyses:

> Enbridge will review the possible inclusion of a long term commodity price forecast that will be based on reasonable predictions, concerning future natural gas price information resulting from an appropriate trading hub, or consultant service forecast for the Enbridge franchise area. This would be an alternative approach to the constant price escalation currently in effect. (Exhibit I.T9.EGDI.GEC.29)

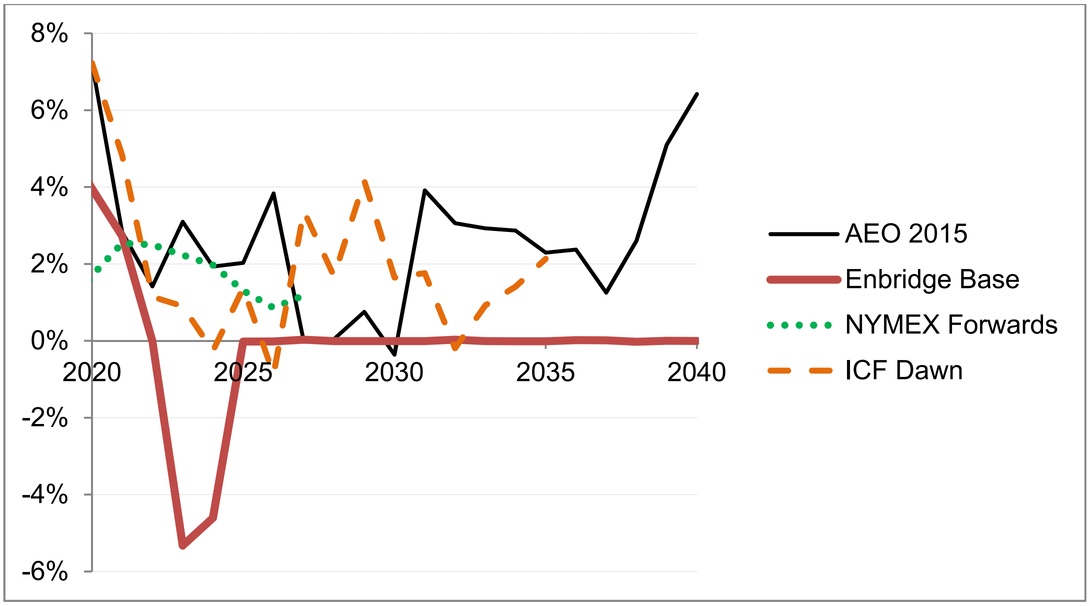
At the Technical Conference, Enbridge indicated that its internal gas supply staff was convinced that the best estimate of gas prices after 2024 was that prices would remain constant in real terms (Tr. 6 July 2015, at 68).

Q: Is a projection of zero real escalation in supply prices after 2024 consistent with general expectations?

A: No. Figure 4 compares the real escalation rates (above inflation) from 2020 onward for Enbridge's avoided supply cost, the 2015 Annual Energy Outlook Henry Hub price, the forecast for Dawn prices by Union's consultant ICF (as a three-year running average), and the July 29 Henry Hub forwards (deflated at 2%).[39]

[39] Enbridge refused to provide the price forecast it received from its forecaster, PIRA (Exhibit I.T9.EGDI.GEC.44).

Figure 4: Comparison of Real Gas Escalation Rates



The other sources do not show the significant real decline in gas prices that Enbridge projects in 2023 and 2024, or the fifteen years of flat real prices from 2025 to 2040.

Q: How does the use of monthly rather than daily gas price inputs understate avoided cost?

A: Daily gas price tends to vary with load. Monthly average price assumes a constant load rather than the typical load shape of a DSM decrement. DSM, in particular weather-sensitive DSM, will avoid more gas on days when prices are higher than Enbridge's methodology assumes.

Q: Has Enbridge provided any documentation of its use of SENDOUT to model transportation and storage costs?

A: No. Its filing included only a statement by Navigant that it had reviewed Enbridge's analysis and found it reasonable:

> During the initial discovery stage of this assignment it was determined that Enbridge's upstream or transmission avoided costs are already fully and accurately captured in their existing avoided cost analysis.

Enbridge refused to provide the basis for Navigant's finding, including the documents it reviewed and analyses it performed.

Q: What documentation did Enbridge provide of Navigant's review of its upstream avoided costs?

A: In Exhibit JT1.23 Enbridge provided Navigant's presentations for Workshop discussions on avoided T&D. In the first workshop, Navigant summarized various avoided T&D methodologies and flagged the question "Upstream Avoided Costs—based on Enbridge's current avoided cost methodology, are all upstream costs included?" as a topic of discussion.

In the second workshop, in a recap of the first, Navigant simply noted that "Enbridge's existing avoided cost calculation methodology (using Sendout) captures all upstream costs."

Q: Do these presentations provide the basis for Navigant's judgment regarding upstream costs?

A: No. They are missing the information Enbridge gave to Navigant. If based solely on the fact that Enbridge used the SENDOUT model, Navigant's judgment is not supported, since, as explained above, user inputs determine the extent to which the SENDOUT model treats upstream costs as avoidable.

Q: What would you look for in an examination of Enbridge's analysis of avoided upstream costs?

A: I would want to make sure that the Enbridge analysis includes whatever costs can be avoided by reduction in load including the following:

- reduction in allocation of Enbridge-owned transmission capacity to retail customers,
- capacity release,

- reduction in pipeline and storage capacity, resulting in reduction in fixed charges.

If Enbridge assumes that its contracts and capacity are not avoidable or that there is no opportunity for capacity release, it is understating the benefits of DSM.

Q: Has Enbridge explained how it treated Segment A of the Greater Toronto Area project for avoided-cost purposes?

A: No.

Q: How should Enbridge treat Segment A of the Greater Toronto Area project for avoided-cost purposes?

A: Enbridge built and sized Segment A to serve its own distribution load with 40% of the capacity and sell the other 60% to TCPL to serve its downstream customers (including parts of Union North, Gaz Métro, and New England utilities and power generators). Reduced Enbridge load would free up additional capacity on Segment A for sale to TCPL or other shippers. Thus, the costs of Segment A are avoidable, and should be treated as such in Enbridge's avoided costs.

2. Union

Q: What is Union's position regarding the reasonableness of its avoided supply costs?

A: Union's perspective is very similar to Enbridge's, although Union is slightly more forthcoming. Union relies on the claim that it is using an established methodology and on the review of its avoided-cost computations by its consultant, ICF.

> Since 2007, Union and Enbridge have used the same methodology in calculating avoided gas costs. In late 2014, Union contracted ICF International to review Union's use of this methodology. The ICF International report, "Evaluation of Union Gas Avoided Costs", can be found at Exhibit A, Tab 2, Appendix C. The purpose of this review was to ensure that the methodology remains an accurate reflection of Union's franchise area and gas supply management policies and practices.
>
> The review concluded that Union's use of this methodology is reasonable and appropriate. (Union Exhibit A.2 at 25)

In the following lines, Union acknowledges that ICF identified four omissions in Union's avoided costs (fuel costs, storage costs, commodity escalation, and T&D), so Union's standard for a "reasonable and appropriate" methodology is rather different than mine.[40]

Q: Was the information that Union provided for ICF's review sufficient for ICF to have found that the Union methodology was "reasonable and appropriate"?

A: No. Union says that the information it provided ICF comprised only the following documentation:

- the 2015-2020 Draft DSM Framework and Guidelines,
- Union's 2012-2014 DSM Plan,
- Union's 2013 Avoided Costs,
- ten Excel files, files as Exhibit B.T9.Union.GEC.65 Excel Attachments 1 through 10 (Exhibit B.T9.Union.GEC.65).

[40]Union's acknowledgement of multiple errors in its prior methodology underscores the importance of examining Union's computations in detail, and not simply verifying that Union used the very general approach approved by the Board.

The Excel files are the only documentation of Union's avoided-cost computations provided to ICF or to the parties. Most of these have little relevance to the actual computation, as follows:

- Attachment 1 summarizes Union's estimated 2013 DSM savings by class and load shape.
- Attachments 2 through 4 contain annual and monthly load data by class and area.
- Attachment 5 contains historical costs for December 2011 to March 2013 and forwards to December 2015 for ten trading nodes, plus the US-Canadian foreign-exchange rate,
- Attachment 6 contains annual demand, cost, and average annual cost (in dollars per cubic metre) for the base case and the changes in demand and cost for the various load shapes for 2014–17, plus similar results "Without Peak Day Demand" and, for each average price, a "Seasonally Adj" value that is usually lower than the calculated value.[41]
- The first sheet of Attachments 7 to 10 each contains a very high-level summary of monthly costs, reporting only the following items:[42]
    - System Supply Costs,
    - Transport Costs South System,
    - Transport Costs North System and DP,
    - Storage Costs.

[41]None of the values in this spreadsheet match the avoided costs that Union provided in Exhibit A, Tab 2, Appendix B.

[42]Most of these values are also reported in the "Cost Compare for all cases" sheet.

The latter two items are reduced by 25% to 30%, as the "DP percentage."

- The worksheet "Draft DSM Monthly Detail" in each of Attachments 7 to 10 provides a list of 4 categories of storage costs, 17 categories of system supply costs, and 19 categories of transport costs. While the table appears to have originally shown the monthly cost for each category for April 2013 to March 2018, all the values have been replaced with "#REF," except for three items that were reported as coming from a "Schedule 15."[43]
- The remaining sheets of Attachments 7 to 10 contain only load data by class.

Q: Are there any informative computations in the Attachments?

A: No. The entries are all values. My description of the DP adjustment, for example, is based on my comparisons of Union's values, not formulas provided by Union.

Q: What questions are raised by Attachments 7 to 10?

A: The first question, of course, is what values, assumptions, and computations went into calculating each of the four cost items computed by Union. A second would be the meaning of the DP adjustment. Third, the treatment of storage costs on Union's southern system is a mystery: Union adds "Transport Costs North System and DP" to "Storage Costs" together to get "Total North System Transport and Storage Costs," suggesting that South System storage costs are omitted. Fourth, the changes in monthly costs with

[43]These are "Added Costs from Sch 15," "Min Flow Stations" and "BT Imbalance Adjustment."

DSM are counterintuitive. For example, going from the base case to the space-heating DSM case entails the following results:[44]

- In most months there is no change in "System Supply Costs" or storage.
- Supply Costs increase in March, May, September, and November, but not in the peak space-heating months.
- Storage costs increase and decrease in individual summer months, balancing out to zero annual change, and with no change in the winter months.
- North Transportation increases every month.

Q: What do you conclude from this analysis of Union's very limited documentation of its computation of avoided supply?

A: The data provided to ICF was insufficient for ICF to find that, as Union maintains, Union had reflected the avoidable upstream transmission costs, to "ensure that the methodology remains an accurate reflection of Union's franchise area and gas supply management policies and practices," or to conclude "that Union's use of this methodology is reasonable and appropriate" (Union Exhibit A.2 at 25). Even after reviewing these spreadsheets, neither I nor ICF can tell whether Union allowed transmission capacity to appropriately adjust to changes in load, whether Union included the allocation of its owned storage and transmission assets to vary with usage, or what prices Union assumed for commodity, transport and storage.

The Attachments to Exhibit B.T9.Union.GEC.65 do indicate a couple of problems. First, it appears that Union did not reflect the reduction in storage

[44]Similar problems appear in the water-heating and industrial runs.

costs for normal-weather operations, as a result of DSM.[45] Second, Union does not appear to have fully reflected the value of space-heating load in the southern territory; it reduced neither winter purchases at Dawn nor the usage of storage to deliver summer gas in the winter.

Q: Did ICF provide any additional information regarding its view as to how Union determined its avoided supply costs?

A: Yes. In its report, ICF provides the following description.

> The pipeline capacity held by Union Gas for each year of the DSM plan is determined by the underlying contracted upstream transportation portfolio in place at the time of the creation of the DSM avoided cost plan and is an input into the SENDOUT model analysis used to estimate overall avoided costs.
>
> Changes in the pipeline capacity portfolio consider the contract expiration schedule on existing pipeline capacity contracts, costs of different supply options, and location of the DSM demand impacts. Generally, the reduction in demand associated with DSM program impacts in the Union North leads to a reduction in the amount of TransCanada Mainline capacity from Empress, while reduction in demand associated with DSM program impacts in the Union southern service territory does not lead to changes in the pipeline portfolio.
>
> Union's analysis of pipeline portfolio requirements currently leads to the conclusion that the changes in demand in the Southern service territory associated with the DSM programs lead to a reduction in citygate purchases at Dawn, rather than a reduction in pipeline capacity under contract into the Union Gas System.

[45] At ICF's recommendation, Union added a small avoided cost for the additional storage that must be kept in reserve to meet the higher design-condition space-heating loads. The capacity costs and variable costs of storage should also be adjusted in the computation of the cost of meeting normal-weather loads.

> A full review of the Union Gas pipeline planning process was beyond the scope of this engagement. However, we note that there likely would be no significant differences in the overall avoided cost estimate if the portfolio planning process determined that a change in pipeline portfolio might be appropriate due to the impacts of the DSM programs. A reduction in pipeline capacity into any supply market would lead to an increase in average commodity prices, offsetting much of the cost savings associated with holding less pipeline capacity. (Union Exhibit A.2 Appendix C, at 21–22)

Q: Can you confirm ICF's conclusions?

A: No. For example, if Union provided ICF with an "analysis of pipeline portfolio requirements" or the "costs of different supply options," Union has failed to provide those documents on discovery, despite representations that it had provided the parties with all information provided to ICF. Indeed, the ICF commentary suggests some of the problems with Union's analysis. If Union allows for reduction in pipeline capacity only consistent with "the contract expiration schedule on existing pipeline capacity contracts," and only models its supply in the first three years (2015–2017), it will never allow DSM to back down pipeline contracts that are up for renewal in any year after 2017.[46]

Q: How does Union treat the costs of its Dawn Parkway pipeline and its Dawn storage for avoided-cost purposes?

A: I do not know. Union acknowledged in the Technical Conference (Tr. July 7, 2015, at 59–60) that the portion of these facilities allocated to Union distribution customers is determined in the cost-allocation process in each

[46]Union refused to provide any information on its supply options, including expiration dates. Nor has Union revealed whether it allowed SENDOUT to vary the amount of capacity on any pipeline other than the TransCanada Mainline capacity from Empress to somewhere in Union's Northern territory.

general rate case. Union staff could not explain how that benefit of DSM was reflected in the SENDOUT runs and Union's avoided costs.

Q: Have you identified any other problem with Union's avoided supply cost analysis?

A: Yes. Union estimates average monthly gas price assuming a constant load over all hours, rather than a typical load shape (Tr. 7/7/15 at 70–72). Therefore, it is likely to have understated the avoided supply costs by ignoring the tendency of gas price to increase with load.

Q: Does this conclude your testimony?

A: Yes, at this time. If more late-filed data become available from the utilities, I may need to update this testimony.

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SUMMARY OF PROFESSIONAL EXPERIENCE

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

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"Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs," Energy Planning Workshops; Columbia, S.C. October 21 1991.

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"Accounting for Externalities: Why, Which and How?" Understanding Massachusetts' New Integrated Resource Management Rules. Needham, Massachusetts, November 9 1990.

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"Assessment and Valuation of External Environmental Damages." New England Utility Rate Forum. Plymouth, Massachusetts, October 11 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

"Reviewing Utility Supply Plans." Massachusetts Energy Facilities Siting Council; Boston, Massachusetts. May 30 1985.

"Power Plant Performance.," National Association of State Utility Consumer Advocates; Williamstown, Massachusetts. August 13 1984.

"Utility Rate Shock," National Conference of State Legislatures; Boston, Massachusetts, August 6 1984.

"Review and Modification of Regulatory and Rate Making Policy," National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20 1984.

"Review and Modification of Regulatory and Rate Making Policy," Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27 1983.

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District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals. August 1987 to March 1988.

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EXPERT TESTIMONY

1. **Mass. EFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General. June 12 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with Susan C. Geller.

2. **Mass. EFSC** 78-17, Northeast Utilities 1978 forecast; Massachusetts Attorney General. September 29 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. **Mass. EFSC** 78-33, Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General. November 27 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. **Mass. DPU** 19494, Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with Susan Geller.

5. **Mass. DPU** 19494, Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **U.S. ASLB** NRC 50-471, Pilgrim Unit 2; Commonwealth of Massachusetts. June 29 1979.

Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with Susan Geller.

7. **Mass.** **DPU** 19845, Boston Edison time-of-use-rate case; Massachusetts Attorney General. December 4 1979. (Not presented)

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with Susan Geller.

8. **Mass.** **DPU** 20055, petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General. January 23 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **Mass.** **DPU** 20248, petition of Massachusetts Municipal Wholesale Electric Company to purchase additional share of Seabrook Nuclear Plant; Massachusetts Attorney General. June 2 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **Mass.** **DPU** 200, Massachusetts Electric Company rate case; Massachusetts Attorney General. June 16 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. **Mass.** **EFSC** 79-33, Eastern Utilities Associates 1979 forecast; Massachusetts Attorney General. July 16 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. **Mass.** **DPU** 243, Eastern Edison Company rate case; Massachusetts Attorney General. August 19 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. **Texas** **PUC** 3298, Gulf States Utilities rate case; East Texas Legal Services. August 25 1980.

Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M. B. Meyer.

14. **Mass. EFSC** 79-1, Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General. November 5 1980.

Cost comparison methodology; nuclear cost estimates; cost of conservation, co-generation, and solar.

15. **Mass. DPU** 472, recovery of residential conservation-service expenses; Massachusetts Attorney General. December 12 1980.

Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

16. **Mass. DPU** 535; regulations to carry out Section 210 of PURPA; Massachusetts Attorney General. January 26 1981 and February 13 1981.

Filing requirements, certification, qualifying-facility status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of qualifying facilities in specific areas; wheeling; standardization of fees and charges.

17. **Mass. EFSC** 80-17, Northeast Utilities 1980 forecast; Massachusetts Attorney General. March 12 1981 (not presented).

Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. **Mass. DPU** 558, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. May 1981.

Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. **Mass. DPU** 1048, Boston Edison plant performance standards; Massachusetts Attorney General. May 7 1982.

Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. **D.C. PSC** FC785, Potomac Electric Power rate case; D.C. People's Counsel. July 29 1982.

Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. **N.H. PSC** DE1-312, Public Service of New Hampshire supply and demand; Conservation Law Foundation et al. October 8 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. **Mass. Division of Insurance,** hearing to fix and establish 1983 automobile insurance rates; Massachusetts Attorney General. October 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. **Ill. Commerce Commission** 82-0026, Commonwealth Edison rate case; Illinois Attorney General. October 15 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. **N.M. PSC** 1794, Public Service of New Mexico application for certification; New Mexico Attorney General. May 10 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. **Conn. DPUC** 830301, United Illuminating rate case; Connecticut Consumers Counsel. June 17 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. **Mass. DPU** 1509, Boston Edison plant performance standards; Massachusetts Attorney General. July 15 1983.

    Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Mass. Division of Insurance,** hearing to fix and establish 1984 automobile-insurance rates; Massachusetts Attorney General. October 1983.

    Profit margin calculations, including methodology, interest rates.

28. **Conn. DPUC** 83-07-15, Connecticut Light and Power rate case; Alloy Foundry. October 3 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **Mass.** **EFSC** 83-24, New England Electric System forecast of electric resources and requirements; Massachusetts Attorney General. November 14 1983, Rebuttal, February 2 1984.

Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Mich.** **PSC** U-7775, Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan. February 21 1984.

Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **Mass.** **DPU** 84-25, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. April 6 1984.

Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **Mass.** **DPU** 84-49 and 84-50, Fitchburg Gas & Electric financing case; Massachusetts Attorney General. April 13 1984.

Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Mich.** **PSC** U-7785, Consumers Power fuel-cost-recovery plan; Public Interest Research Group in Michigan. April 16 1984.

Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC** ER81-749-000 and ER82-325-000, Montaup Electric rate cases; Massachusetts Attorney General. April 27 1984.

Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. **Maine** **PUC** 84-113, Seabrook-1 investigation; Maine Public Advocate. September 13 1984.

Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. **Mass. DPU** 84-145, Fitchburg Gas and Electric rate case; Massachusetts Attorney General. November 6 1984.

    Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. **Penn. PUC** R-842651, Pennsylvania Power and Light rate case; Pennsylvania Consumer Advocate. November 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. **N.H. PSC** 84-200, Seabrook Unit-1 investigation; New Hampshire Public Advocate. November 15 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. **Mass. Division of Insurance,** hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General. November 1984.

    Profit-margin calculations, including methodology and implementation.

40. **Mass. DPU** 84-152, Seabrook Unit 1 investigation; Massachusetts Attorney General. December 12 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. **Maine PUC** 84-120; Central Maine Power rate case; Maine PUC Staff. December 11 1984.

    Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. **Maine PUC** 84-113, Seabrook 2 investigation; Maine PUC Staff. December 14 1984.

Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. **Mass. DPU** 1627, Massachusetts Municipal Wholesale Electric Company financing case; Massachusetts Executive Office of Energy Resources. January 14 1985.

    Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. **Vt. PSB** 4936, Millstone 3 costs and in-service date; Vermont Department of Public Service. January 21 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. **Mass. DPU** 84-276, rules governing rates for utility purchases of power from qualifying facilities; Massachusetts Attorney General. March 25 1985 and October 18 1985.

    Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. **Mass. DPU** 85-121, investigation of the Reading Municipal Light Department; Wilmington (Mass.) Chamber of Commerce. November 12 1985.

    Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. **Mass. Division of Insurance,** hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. November 1985.

    Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. **N.M. PSC** 1833, Phase II; El Paso Electric rate case; New Mexico Attorney General. December 23 1985.

    Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. **Penn. PUC** R-850152, Philadelphia Electric rate case; Utility Users Committee and University of Pennsylvania. January 14 1986.

    Limerick-1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. **Mass. DPU** 85-270;, Western Massachusetts Electric rate case; Massachusetts Attorney General. March 19 1986.

    Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. **Penn. PUC** R-850290, Philadelphia Electric auxiliary service rates; Albert Einstein Medical Center, University of Pennsylvania, and Amtrak. March 24 1986.

    Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. **N.M. PSC** 2004, Public Service of New Mexico Palo Verde issues; New Mexico Attorney General. May 7 1986.

    Recommendations for power-plant performance standards for Palo Verde nuclear units 1, 2, and 3.

53. **Ill. Commerce Commission** 86-0325, Iowa-Illinois Gas and Electric Co. rate investigation; Illinois Office of Public Counsel. August 13 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **N.M. PSC** 2009, El Paso Electric rate moderation program; New Mexico Attorney General. August 18 1986. (Not presented).

    Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

    Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston Public Improvements Commission,** transfer of Boston Edison district heating steam system to Boston Thermal Corporation; Boston Housing Authority. December 18 1986.

History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Mass. Division of Insurance,** hearing to fix and establish 1987 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. **Mass. DPU** 87-19, petition for adjudication of development facilitation program; Hull (Mass.) Municipal Light Plant. January 21 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **N.M. PSC** 2004, Public Service of New Mexico nuclear decommissioning fund; New Mexico Attorney General. February 19 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **Mass. DPU** 86-280, Western Massachusetts Electric rate case; Massachusetts Energy Office. March 9 1987.

    Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of Consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. **Mass. Division of Insurance** 87-9, 1987 Workers' Compensation rate filing; State Rating Bureau. May 1987.

    Profit-margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. **Texas PUC** 6184, economic viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief. August 17 1987.

    Nuclear plant operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP-2 cost and schedule projections. Potential for conservation.

62. **Minn. PUC** ER-015/GR-87-223, Minnesota Power rate case; Minnesota Department of Public Service. August 17 1987.

Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. **Mass. Division of Insurance** 87-27, 1988 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. September 2 1987. Rebuttal October 8 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. **Mass. DPU** 88-19, power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric. November 4 1987.

    Comparison of risk from QF contract and utility avoided-cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. **Mass. Division of Insurance** 87-53, 1987 Workers' Compensation rate refiling; State Rating Bureau. December 14 1987.

    Profit-margin calculations including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. **Mass. Division of Insurance,** 1987 and 1988 automobile insurance remand rates; Massachusetts Attorney General and State Rating Bureau. February 5 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **Mass. DPU** 86-36, investigation into the pricing and ratemaking treatment to be afforded new electric generating facilities which are not qualifying facilities; Conservation Law Foundation. May 2 1988.

    Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. **Mass. DPU** 88-123, petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company. May 18 1988 and November 8 1988.

    Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **Mass. DPU** 88-67, Boston Gas Company; Boston Housing Authority. June 17 1988.

Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **R.I. PUC** 1900, Providence Water Supply Board tariff filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island. June 24 1988.

    Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. **Mass. Division of Insurance** 88-22, 1989 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues, August 12 1988, supplemented August 19 1988; Losses and Expenses, September 16 1988.

    Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. **Vt. PSB** 5270 Module 6, investigation into least-cost investments, energy efficiency, conservation, and the management of demand for energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group. September 26 1988.

    Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. **Vt. House of Representatives, Natural Resources Committee,** House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group. February 21 1989.

    Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. **Mass. DPU** 88-67 Phase II, Boston Gas company conservation program and rate design; Boston Gas Company. March 6 1989.

    Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. **Vt. PSB** 5270, status conference on conservation and load management policy settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service. May 1 1989.

    Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. **Boston Housing Authority Court** 05099, Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority. June 16 1989.

Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. **Mass.** **DPU** 89-100, Boston Edison rate case; Massachusetts Energy Office. June 30 1989.

Prudence of BECo's decision to spend $400 million from 1986–88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. **Mass.** **DPU** 88-123, petition of Riverside Steam and Electric Company; Riverside Steam and Electric. July 24 1989. Rebuttal, October 3 1989.

Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. **Mass.** **DPU** 89-72, Statewide Towing Association police-ordered towing rates; Massachusetts Automobile Rating Bureau. September 13 1989.

Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. **Vt.** **PSB** 5330, application of Vermont utilities for approval of a firm power and energy contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group. December 19 1989. Surrebuttal February 6 1990.

Analysis of a proposed 450-MW, 20-year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. **Mass.** **DPU** 89-239, inclusion of externalities in energy-supply planning, acquisition, and dispatch for Massachusetts utilities. December 1989; April 1990; May 1990.

Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. **California PUC,** incorporation of environmental externalities in utility planning and pricing; Coalition of Energy Efficient and Renewable Technologies. February 21 1990.

Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. **Ill. Commerce Commission** 90-0038, proceeding to adopt a least-cost electric-energy plan for Commonwealth Edison Company; City of Chicago. May 25 1990. Joint rebuttal testimony with David Birr, August 14 1990.

Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. **Md. PSC** 8278, adequacy of Baltimore Gas & Electric's integrated resource plan; Maryland Office of People's Counsel. September 18 1990.

Rationale for demand-side management. BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. **Ind. Utility Regulatory Commission,** integrated-resource-planning docket; Indiana Office of Utility Consumer Counselor. November 1 1990.

Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. **Mass. DPU** 89-141, 90-73, 90-141, 90-194, 90-270; preliminary review of utility treatment of environmental externalities in October qualifying-facilities filings; Boston Gas Company. November 5 1990.

Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. **Mass. EFSC** 90-12/90-12A, adequacy of Boston Edison proposal to build combined-cycle plant; Conservation Law Foundation. December 14 1990.

Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. **Maine PUC** 90-286, adequacy of conservation program of Bangor Hydro Electric; Penobscot River Coalition. February 19 1991.

Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. **Va. SCC** PUE900070, Order establishing commission investigation; Southern Environmental Law Center. March 6 1991.

Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. **Mass. DPU** 90-261-A, economics and role of fuel-switching in the DSM program of the Massachusetts Electric Company; Boston Gas Company. April 17 1991.

    Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. **Private arbitration,** Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech. May 13 1991.

    NEPCo rates for power purchases from the New England Solid Waste Compact plant. Fuel price and avoided cost projections vs. realities.

92. **Vt. PSB** 5491, cost-effectiveness of Central Vermont's commitment to Hydro Quebec purchases; Conservation Law Foundation. July 19 1991.

    Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. **S.C. PSC** 91-216-E, cost recovery of Duke Power's DSM expenditures; South Carolina Department of Consumer Affairs. Direct, September 13 1991; Surrebuttal October 2 1991.

    Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. **Md. PSC** 8241 Phase II, review of Baltimore Gas & Electric's avoided costs; Maryland Office of People's Counsel. September 19 1991.

    Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. **Bucksport (Maine) Planning Board,** AES/Harriman Cove shoreland zoning application; Conservation Law Foundation and Natural Resources Council of Maine. October 1 1991.

    New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. **Mass. DPU** 91-131, update of externalities values adopted in Docket 89-239; Boston Gas Company. October 4 1991. Rebuttal, December 13 1991.

    Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. **Fla.** PSC 910759, petition of Florida Power Corporation for determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 21 1991.

    Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. **Fla.** PSC 910833-EI, petition of Tampa Electric Company for a determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 31 1991.

    Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. **Penn.** PUC I-900005, R-901880; investigation into demand-side management by electric utilities; Pennsylvania Energy Office. January 10 1992.

    Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. **S.C.** PSC 91-606-E, petition of South Carolina Electric and Gas for a certificate of public convenience and necessity for a coal-fired plant; South Carolina Department of Consumer Affairs. January 20 1992.

    Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. **Mass.** DPU 92-92, adequacy of Boston Edison's street-lighting options; Town of Lexington. June 22 1992.

    Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.

102. **S.C.** PSC 92-208-E, integrated-resource plan of Duke Power Company; South Carolina Department of Consumer Affairs. August 4 1992.

    Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. **N.C. Utilities Commission** E-100 Sub 64, integrated-resource-planning docket; Southern Environmental Law Center. September 29 1992.

    General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. **Ont. EAB** Ontario Hydro Demand/Supply Plan Hearings, *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); Coalition of Environmental Groups. October 1992.

Valuation of environmental externalities from fossil fuel combustion and the nuclear fuel cycle. Application to Ontario Hydro's supply and demand planning.

105. **Texas PUC** 110000, application of Houston Lighting and Power company for a certificate of convenience and necessity for the DuPont Project; Destec Energy, Inc. September 28 1992.

Valuation of environmental externalities from fossil fuel combustion and the application to the evaluation of proposed cogeneration facility.

106. **Maine BEP,** in the matter of the Basin Mills Hydroelectric Project application; Conservation Intervenors. November 16 1992.

Economic and environmental effects of generation by proposed hydro-electric project.

107. **Md. PSC** 8473, review of the power sales agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel. November 16 1992.

Non-price scoring and unquantified benefits; DSM potential as alternative; environmental costs; cost and benefit estimates.

108. **N.C. Utilities Commission** E-100 Sub 64, analysis and investigation of least cost integrated resource planning in North Carolina; Southern Environmental Law Center. November 18 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **S.C. PSC** 92-209-E, in re Carolina Power & Light Company; South Carolina Department of Consumer Affairs. November 24 1992.

Demand-side-management planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.

110 **Fla. DER** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation. December 1992.

Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.

111. **Md. PSC** 8487, Baltimore Gas and Electric Company electric rate case. Direct, January 13 1993; rebuttal, February 4 1993.

Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.

112. **Md.** **PSC** 8179, Approval of amendment no. 2 to Potomac Edison purchase agreement with AES Warrior Run; Maryland Office of People's Counsel. January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

113. **Mich.** **PSC** U-10102, Detroit Edison rate case; Michigan United Conservation Clubs. February 17 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

114. **Ohio** **PUC** 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati Gas and Electric demand-management programs; City of Cincinnati. April 1993.

Demand-side-management planning, program designs, potential savings, and avoided costs.

115. **Mich.** **PSC** U-10335, Consumers Power rate case; Michigan United Conservation Clubs. October 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

116. **Ill. Commerce Commission** 92-0268, electric-energy plan for Commonwealth Edison; City of Chicago. Direct, February 1 1994; rebuttal, September 1994.

Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

117. **FERC** 2422 et al., application of James River–New Hampshire Electric, Public Service of New Hampshire, for licensing of hydro power; Conservation Law Foundation; 1993.

Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

118. **Vt.** **PSB** 5270-CV-1,-3, and 5686; Central Vermont Public Service fuel-switching and DSM program design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.

119. **Fla.** **PSC** 930548-EG–930551-EG, conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.

Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

120. **Vt. PSB** 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.

121. **Mass. DPU** 94-49, Boston Edison integrated-resource-management plan; Massachusetts Attorney General. August 1994.

Least-cost planning, modeling, and treatment of risk.

122. **Mich. PSC** U-10554, Consumers Power Company DSM program and incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. **Mich. PSC** U-10702, Detroit Edison Company cost recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

124. **N.J. BRC** EM92030359, environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

125. **Mich. PSC** U-10671, Detroit Edison Company DSM programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. **Mich. PSC** U-10710, power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

127. **FERC** 2458 and 2572, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

128. **N.C. Utilities Commission** E-100 Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

129. **New Orleans City Council** UD-92-2A and -2B, least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

Critique of proposal to scale back DSM efforts in light of potential competition.

130. **D.C. PSC** FC917 II, prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.

131. **Ont. Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

Demand-side-management cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

132. **New Orleans City Council** CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

Allocation of costs and benefits to rate classes.

133. **Mass. DPU** Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.

Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.

134. **Md. PSC** 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995.

Rate design, cost-of-service study, and revenue allocation.

135. **N.C. Utilities Commission** E-2 Sub 669. December 1995.

Need for new capacity. Energy-conservation potential and model programs.

136. **Arizona Commerce Commission** U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.

137. Ohio PUC 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

138 Vt. PSB 5835, Central Vermont Public Service Company rates; Vermont Department of Public Service. February 1996.

Design of load-management rates of Central Vermont Public Service Company.

139. Md. PSC 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

Avoided costs of Washington Gas Light Company; integrated least-cost planning.

140. Mass. DPU 96-100, Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.

Stranded costs. Calculation of loss or gain. Valuation of utility assets.

141. Mass. DPU 96-70, Essex County Gas Company rates; Massachusetts Attorney General. July 1996.

Market-based allocation of gas-supply costs of Essex County Gas Company.

142. Mass. DPU 96-60, Fall River Gas Company rates; Massachusetts Attorney General. Direct, July 1996; surrebuttal, August 1996.

Market-based allocation of gas-supply costs of Fall River Gas Company.

143. Md. PSC 8725, Maryland electric-utilities merger; Maryland Office of People's Counsel. July 1996.

Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.

144. N.H. PUC DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges.

145. **Ont. Energy Board** EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

LRAM and shared-savings incentive mechanisms in rates for the Consumers Gas Company Ltd.

146. **New York PSC** 96-E-0897, Consolidated Edison restructuring plan; City of New York. April 1997.

Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

147. **Vt. PSB** 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.

148. **Mass. DPU** 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

149. **Vt. PSB** 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.

150. **Mass. DPU** 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.

151. **Mass. DTE** 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

152. **N.H. PUC** Docket DR 97-241, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.

Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.

153. **Md. PSC** 8774, APS-DQE merger; Maryland Office of People's Counsel. February 1998.

Power-supply arrangements between APS's operating subsidiaries; power-supply savings; market power.

154. **Vt. PSB** 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

155. **Maine PUC** 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.

156. **Mass. DTE** 98-89, purchase of Boston Edison municipal street lighting; Towns of Lexington and Acton. Affidavit, August 1998.

Valuation of municipal streetlighting; depreciation; applicability of unbundled rate.

157. **Vt. PSB** 6107, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, September 1998; Surrebuttal drafted but not filed, November 2000.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.

158. **Mass. DTE** 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October 1998. Joint surrebuttal with Jonathan Wallach, January 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

159. **Md. PSC** 8794 and 8804, BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December 1998; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

160. **Md. PSC** 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

161. **Md. PSC** 8797, Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

162. Conn. DPUC 99-02-05, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear and non-nuclear assets from comparable-sales and cash-flow analyses.

163. Conn. DPUC 99-03-04, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear assets from comparable-sales and cash-flow analyses.

164. Wash. UTC UE-981627, PacifiCorp–Scottish Power merger, Office of the Attorney General. June 1999.

Review of proposed performance standards and valuation of performance. Review of proposed low-income assistance.

165. Utah PSC 98-2035-04, PacifiCorp–Scottish Power merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

166. Conn. DPUC 99-03-35, United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost

167. Conn. DPUC 99-03-36, Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; supplemental, July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost.

168. W. Va. PSC 98-0452-E-GI, electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

Market value of generating assets of, and restructuring gain for, Potomac Edison, Monongahela Power, and Appalachian Power. Comparable-sales and cash-flow analyses.

169. Ont. Energy Board RP-1999-0034, Ontario performance-based rates; Green Energy Coalition. September 1999.

Rate design. Recovery of demand-side-management costs under PBR. Incremental costs.

170. Conn. DPUC 99-08-01, standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; supplemental, January 2000.

Appropriate role of regulation. T&D reliability and service quality. Performance standards and customer guarantees. Assessing generation adequacy in a competitive market.

171. **Conn. Superior Court** CV 99-049-7239, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

Errors of the Conn. DPUC in deriving discounted-cash-flow valuations for Millstone and Seabrook, and in setting minimum bid price.

172. **Conn. Superior Court** CV 99-049-7597, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. December 1999.

Errors of the Conn. DPUC, in its discounted-cash-flow computations, in selecting performance assumptions for Seabrook, and in setting minimum bid price.

173. **Ont. Energy Board** RP-1999-0044, Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.

Cost allocation and rate design. Net vs. gross load billing. Export and wheeling-through transactions. Environmental implications of utility proposals.

174. **Utah PSC** 99-2035-03, PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.

Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.

175. **Conn. DPUC** 99-09-12, Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.

Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.

176. **Ont. Energy Board** RP-1999-0017, Union Gas PBR proposal; Green Energy Coalition. March 2000.

Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.

177. **N.Y. PSC** 99-S-1621, Consolidated Edison steam rates; City of New York. April 2000.

Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.

178. **Maine PUC** 99-666, Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.

Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

179. **Mass.** **EFSB** 97-4, Massachusetts Municipal Wholesale Electric Company gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

Economic justification for natural-gas pipeline. Role and jurisdiction of EFSB.

180. **Conn.** **DPUC** 99-09-03; Connecticut Natural Gas Corporation merger and rate plan; Connecticut office of Consumer Counsel. September 2000.

Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.

181. **Conn.** **DPUC** 99-09-12RE01, Proposed Millstone sale; Connecticut Office of Consumer Counsel. November 2000.

Requirements for review of auction of generation assets. Allocation of proceeds between units.

182. **Mass.** **DTE** 01-25, Purchase of streetlights from Commonwealth Electric; Cape Light Compact. January 2001

Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.

183. **Conn.** **DPUC** 00-12-01 and 99-09-12RE03, Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March 2001.

Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.

184. **Vt.** **PSB** 6460 & 6120, Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.

Review of decision in early 1990s to commit to long-term uneconomic purchase from Hydro Québec. Calculation of present damages from imprudence.

185. **N.J.** **BPU** EM00020106, Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.

Comparison of power-supply contracts. Comparison of plant costs to replacement power cost. Allocation of sales proceeds between subsidiaries.

186. **N.J.** **BPU** GM00080564, Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.

Transfer of gas transportation contracts to unregulated affiliate. Potential for market power in wholesale gas supply and electric generation. Importance of reliable gas supply. Valuation of contracts. Effect of proposed requirements contract on rates. Regulation and design of standard-offer service.

187. Conn. **DPUC** 99-04-18 Phase 3, 99-09-03 Phase 2; Southern Connecticut Natural Gas and Connecticut Natural Gas rates and charges; Connecticut Office of Consumer Counsel. Direct, June 2001; supplemental, July 2001.

Identifying, quantifying, and allocating merger-related gas-supply savings between ratepayers and shareholders. Establishing baselines. Allocations between affiliates. Unaccounted-for gas.

188. N.J. BPU EX01050303, New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.

Review of proposed statewide auction for purchase of power requirements. Market power. Risks to ratepayers of proposed auction.

189. N.Y. **PSC** 00-E-1208, Consolidated Edison rates; City of New York. October 2001.

Geographic allocation of stranded costs. Locational and postage-stamp rates. Causation of stranded costs. Relationship between market prices for power and stranded costs.

190. Mass. **DTE** 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

Allocation of gas costs by load shape and season. Competition and cost allocation.

191. N.J. **BPU** EM00020106, Atlantic City Electric proposed sale of fossil plants; New Jersey Ratepayer Advocate. December 2001.

Current market value of generating plants vs. proposed purchase price.

192. Vt. **PSB** 6545, Vermont Yankee proposed sale; Vermont Department of Public Service. January 2002.

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Review of auction manager's valuation of bids.

193. Conn. Siting Council 217, Connecticut Light & Power proposed transmission line from Plumtree to Norwalk; Connecticut Office of Consumer Counsel. March 2002.

Nature of transmission problems. Potential for conservation and distributed resources to defer, reduce or avoid transmission investment. CL&P transmission planning process. Joint testimony with John Plunkett.

194. Vt. **PSB** 6596, Citizens Utilities rates; Vermont Department of Public Service. Direct, March 2002; rebuttal, May 2002.

Review of 1991 decision to commit to long-term uneconomic purchase from Hydro Québec. Alternatives; role of transmission constraints. Calculation of present damages from imprudence.

195. Conn. **DPUC** 01-10-10, United Illuminating rate plan; Connecticut Office of Consumer Counsel. April 2002

Allocation of excess earnings between shareholders and ratepayers. Asymmetry in treatment of over- and under-earning. Accelerated amortization of stranded costs. Effects of power-supply developments on ratepayer risks. Effect of proposed rate plan on utility risks and required return.

196. Conn. DPUC 01-12-13RE01, Seabrook proposed sale; Connecticut Office of Consumer Counsel. July 2002

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Assessment of valuation of purchased-power contracts.

197. Ont. Energy Board RP-2002-0120, review of transmission-system code; Green Energy Coalition. October 2002.

Cost allocation. Transmission charges. Societal cost-effectiveness. Environmental externalities.

198. N.J. BPU ER02080507, Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II (oral) July 2003.

Prudence of procurement of electrical supply. Documentation of procurement decisions. Comparison of costs for subsidiaries with fixed versus flow-through cost recovery.

199. Conn. DPUC 03-07-02, CL&P rates; AARP. October 2003

Proposed distribution investments, including prudence of prior management of distribution system and utility's failure to make investments previously funded in rates. Cost controls. Application of rate cap. Legislative intent.

200. Conn. DPUC 03-07-01, CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

201. Vt. PSB 6596, Vermont Electric Power Company and Green Mountain Power Northwest Reliability transmission plan; Conservation Law Foundation. December 2003.

Inadequacies of proposed transmission plan. Failure of to perform least-cost planning. Distributed resources.

202. Ohio PUC 03-2144-EL-ATA, Ohio Edison, Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. February 2004.

Pricing of standard-offer service in competitive markets. Critique of anticompetitive features of proposed standard-offer supply, including non-bypassable charges.

203. N.Y. PSC 03-G-1671 & 03-S-1672, Consolidated Edison company steam and gas rates; City of New York. Direct March 2004; rebuttal April 2004; settlement June 2004.

Prudence and cost allocation for the East River Repowering Project. Gas and steam energy conservation. Opportunities for cogeneration at existing steam plants.

204. N.Y. PSC 04-E-0572, Consolidated Edison rates and performance; City of New York. Direct, September 2004; rebuttal, October 2004.

Consolidated Edison's role in promoting adequate supply and demand resources. Integrated resource and T&D planning. Performance-based ratemaking and streetlighting.

205. Ont. Energy Board RP 2004-0188, cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, December 2004.

Differences in ratemaking requirements for customer-side conservation and demand management versus utility-side efficiency improvements. Recovery of lost revenues or incentives. Reconciliation mechanism.

206. Mass. DTE 04-65, Cambridge Electric Light Co. streetlighting; City of Cambridge. Direct, October 2004; supplemental, January 2005.

Calculation of purchase price of street lights by the City of Cambridge.

207. N.Y. PSC 04-W-1221, rates, rules, charges, and regulations of United Water New Rochelle; Town of Eastchester and City of New Rochelle. Direct, February 2005.

Size and financing of proposed interconnection. Rate design. Water-mains replacement and related cost recovery. Lost and unaccounted-for water.

208. N.Y. PSC 05-M-0090, system-benefits charge; City of New York. Comments, March 2005.

Assessment and scope of, and potential for, New York system-benefits charges.

209. Md. PSC 9036, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, August 2005.

Allocation of costs. Design of rates. Interruptible and firm rates.

210. B.C. Utilities Commission 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. September 2005.

Renewable energy and DSM. Economic tests of cost-effectiveness. Costs avoided by DSM.

211. Conn. DPUC 05-07-18, financial effect of long-term power contracts; Connecticut Office of Consumer Counsel. September 2005.

Assessment of effect of DSM, distributed generation, and capacity purchases on financial condition of utilities.

212. Conn. **DPUC** 03-07-01RE03 & 03-07-15RE02, incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005; Additional, April 2006.

Utility obligations for generation procurement. Application of standards for utility incentives. Identification and quantification of effects of timing, load characteristics, and product definition.

213. Conn. **DPUC** Docket 05-10-03, Connecticut L&P; time-of-use, interruptible, and seasonal rates; Connecticut Office of Consumer Counsel. Direct and Supplemental Testimony February 2006.

Seasonal and time-of-use differentiation of generation, congestion, transmission and distribution costs; fixed and variable peak-period timing; identification of pricing seasons and seasonal peak periods; cost-effectiveness of time-of-use rates.

214. Ont. Energy Board Case EB-2005-0520, Union Gas rates; School Energy Coalition. Evidence, April 2006.

Rate design related to splitting commercial rate class into two classes. New break point, cost allocation, customer charges, commodity rate blocks.

215. Ont. Energy Board EB-2006-0021, Natural-gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

Multi-year planning and budgeting; lost-revenue adjustment mechanism; determining savings for incentives; oversight; program screening.

216. Ind. Utility Regulatory Commission 42943 and 43046, Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. Penn. **PUC** 00061346, Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; benefits of time-dependent pricing; appropriate metering technology; real-time rate design and customer information

218. Penn. **PUC** R-00061366 et al., rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; appropriate metering technology; real-time rate design and customer information.

219. Conn. **DPUC** 06-01-08, Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly since September 2006.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

220. Conn. **DPUC** 06-01-08, United Illuminating procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly since August 2006.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

221. N.Y. **PSC** Case No. 06-M-1017, policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.

Multi-year contracts, long-term planning, new resources, procurement by utilities and other entities, cost recovery.

222. Conn. **DPUC** 06-01-08, procurement of power for standard service and last-resort service, lessons learned; Connecticut Office Of Consumer Counsel. Comments and Technical Conferences December 2006 and January 2007.

Sharing of data and sources; benchmark prices; need for predictability, transparency and adequate review; utility-owned resources; long-term firm contracts.

223. Ohio **PUC** PUCO 05-1444-GA-UNC, recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. February 2007.

Assessing cost-effectiveness of natural-gas energy-efficiency programs. Calculation of avoided costs. Impact on rates. System benefits of DSM.

224. N.Y. **PSC** 06-G-1332, Consolidated Edison Rates and Regulations; City of New York. March 2007.

Gas energy efficiency: benefits to customers, scope of cost-effective programs, revenue decoupling, shareholder incentives.

225. Alb. **EUB** 1500878, ATCo Electric rates; Association of Municipal Districts & Counties and Alberta Federation of Rural Electrical Associations. May 2007.

Direct assignment of distribution costs to street lighting. Cost causation and cost allocation. Minimum-system and zero-intercept classification.

226. Conn. **DPUC** 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

227. **N.Y. PSC** 07-E-0524, Consolidated Edison electric rates; City of New York. September 2007.

Energy-efficiency planning. Recovery of DSM costs. Decoupling of rates from sales. Company incentives for DSM. Advanced metering. Resource planning.

228. **Man. PUB** 136-07, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. February 2008.

Revenue allocation, rate design, and demand-side management. Estimation of marginal costs and export revenues.

229. **Mass. EFSB** 07-7, DPU 07-58 & -59; proposed Brockton Power Company plant; Alliance Against Power Plant Location. March 2008

Regional supply and demand conditions. Effects of plant construction and operation on regional power supply and emissions.

230. **Conn. DPUC** 08-01-01, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

231. **Ont. Energy Board** 2007-0905, Ontario Power Generation payments; Green Energy Coalition. April 2008.

Cost of capital for Hydro and nuclear investments. Financial risks of nuclear power.

232. **Utah** PSC 07-035-93, Rocky Mountain Power Rates; Utah Committee of Consumer Services. July 2008

Cost allocation and rate design. Cost of service. Correct classification of generation, transmission, and purchases.

233. **Ont. Energy Board** 2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Jonathan Wallach and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

234. **N.Y. PSC** 08-E-0596, Consolidated Edison electric rates; City of New York. September 2008.

Estimated bills, automated meter reading, and advanced metering. Aggregation of building data. Targeted DSM program design. Using distributed generation to defer T&D investments.

235. **Conn. DPUC** 08-07-01, Integrated resource plan; Connecticut Office of Consumer Counsel. September 2008.

Integrated resource planning scope and purpose. Review of modeling and assumptions. Review of energy efficiency, peakers, demand response, nuclear, and renewables. Structuring of procurement contracts.

236. **Man. PUB** 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. November 2008.

Marginal costs. Rate design. Time-of-use rates.

237. **Md. PSC** 9036, Columbia Gas rates; Maryland Office of People's Counsel. January 2009.

Cost allocation and rate design. Critique of cost-of-service studies.

238. **Vt. PSB** 7440, extension of authority to operate Vermont Yankee; Conservation Law Foundation and Vermont Public Interest Research Group. Direct, February 2009; Surrebuttal, May 2009.

Adequacy of decommissioning funding. Potential benefits to Vermont of revenue-sharing provision. Risks to Vermont of underfunding decommissioning fund.

239. **N.S. UARB** 01439, Nova Scotia Power DSM and cost recovery; Nova Scotia Consumer Advocate. May 2009.

Recovery of demand-side-management costs and lost revenue.

240. **N.S. UARB** 0496, proposed biomass project; Nova Scotia Consumer Advocate. June 2009.

Procedural, planning, and risk issues with proposed power-purchase contract. Biomass price index. Nova Scotia Power's management of other renewable contracts.

241. **Conn. Siting Council** 370A, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. July 2009.

Need for transmission projects. Modeling of transmission system. Realistic modeling of operator responses to contingencies

242. **Mass. DPU** 09-39, NGrid rates; Mass. Department of Energy Resources. August 2009.

Revenue-decoupling mechanism. Automatic rate adjustments.

243. **Utah PSC** 09-035-23, Rocky Mountain Power rates; Utah Office of Consumer Services. Direct, October 2009; rebuttal, November 2009.

Cost-of-service study. Cost allocators for generation, transmission, and substation.

244. **Utah PSC** 09-035-15, Rocky Mountain Power energy-cost-adjustment mechanism; Utah Office of Consumer Services. Direct, November 2009; surrebuttal, January 2010.

Automatic cost-adjustment mechanisms. Net power costs and related risks. Effects of energy-cost-adjustment mechanisms on utility performance.

245. **Penn. PUC** R-2009-2139884, Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. December 2009.

Avoided gas costs. Recovery of efficiency-program costs and lost revenues. Rate impacts of DSM.

246. **B.C. Utilities Commission** 3698573, British Columbia Hydro rates; British Columbia Sustainable Energy Association and Sierra Club British Columbia. February 2010.

Rate design and energy efficiency.

247. **Ark. PSC** 09-084-U, Entergy Arkansas rates; National Audubon Society and Audubon Arkansas. Direct, February 2010; surrebuttal, April 2010.

Recovery of revenues lost to efficiency programs. Determination of lost revenues. Incentive and recovery mechanisms.

248. **Ark. PSC** 10-010-U, Energy efficiency; National Audubon Society and Audubon Arkansas. Direct, March 2010; reply, April 2010.

Regulatory framework for utility energy-efficiency programs. Fuel-switching programs. Program administration, oversight, and coordination. Rationale for commercial and industrial efficiency programs. Benefit of energy efficiency.

249. **Ark. PSC** 08-137-U, Generic rate-making; National Audubon Society and Audubon Arkansas. Direct, March 2010; supplemental, October 2010; reply, October 2010.

Calculation of avoided costs. Recovery of utility energy-efficiency-program costs and lost revenues. Shareholder incentives for efficiency-program performance.

250. **Plymouth, Mass., Superior Court** Civil Action No. PLCV2006-00651-B (Hingham Municipal Lighting Plant v. Gas Recovery Systems LLC et al.), Breach of agreement; defendants. Affidavit, May 2010.

Contract interpretation. Meaning of capacity measures. Standard practices in capacity agreements. Power-pool rules and practices. Power planning and procurement.

251. **N.S. UARB** 02961, Port Hawkesbury biomass project; Nova Scotia Consumer Advocate. June 2010.

Least-cost planning and renewable-energy requirements. Feasibility versus alternatives. Unknown or poorly estimated costs.

252. **Mass. DPU** 10-54, NGrid purchase of long-term power from Cape Wind; Natural Resources Defense Council et al. July 2010.

Effects of renewable-energy projects on gas and electric market prices. Impacts on system reliability and peak loads. Importance of PPAs to renewable development. Effectiveness of proposed contracts as price edges.

253. **Md. PSC** 9230, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, July 2010; rebuttal, surrebuttal, August 2010.

Allocation of gas- and electric-distribution costs. Critique of minimum-system analyses and direct assignment of shared plant. Allocation of environmental compliance costs. Allocation of revenue increases among rate classes.

254. **Ont. Energy Board** 2010-0008, Ontario Power Generation facilities charges; Green Energy Coalition. Evidence, August 2010.

Critique of including a return on CWIP in current rates. Setting cost of capital by business segment.

255. **N.S. UARB** Matter No. 03454, Heritage Gas rates; Nova Scotia Consumer Advocate. October 2010.

Cost allocation. Cost of capital. Effect on rates of growth in sales.

256. **Man. PUB** 17/10, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. December 2010.

Revenue-allocation and rate design. DSM program.

257. **N.S. UARB** 03665, Nova Scotia Power depreciation rates; Nova Scotia Consumer Advocate. February 2011.

Depreciation and rates.

258. **New Orleans City Council** UD-08-02, Entergy IRP rules; Alliance for Affordable Energy. December 2010.

Integrated resource planning: Purpose, screening, cost recovery, and generation planning.

259. **N.S. UARB** NSPI-P-892, depreciation Rates of Nova Scotia Power; Nova Scotia Consumer Advocate. February 2011.

Steam-plant retirement dates, post-retirement use, timing of decommissioning and removal costs.

260. **N.S. UARB** 03632, renewable-energy community-based feed-in tariffs; Nova Scotia Consumer Advocate. March 2011.

Adjustments to estimate of cost-based feed-in tariffs. Rate effects of feed-in tariffs.

261. **Mass.** **EFSB** 10-2/DPU 10-131, 10-132; NStar transmission; Town of Sandwich, Mass. Direct, May 2011; Surrebuttal, June 2011.

Need for new transmission; errors in load forecasting; probability of power outages.

262. **Utah** **PSC** 10-035-124, Rocky Mountain Power rate case; Utah Office of Consumer Services. June 2011.

Load data, allocation of generation plants, scrubbers, power purchases, and service drops. Marginal cost study: inclusion of all load-related transmission projects, critique of minimum- and zero-intercept methods for distribution. Residential rate design.

263. **N.S.** **UARB** 04104; Nova Scotia Power general rate application; Nova Scotia Consumer Advocate. August 2011.

Cost allocation: allocation of costs of wind power and substations. Rate design: marginal-cost-based rates, demand charges, time-of-use rates.

264. **N.S.** **UARB** 04175, Load-retention tariff; Nova Scotia Consumer Advocate. August 2011.

Marginal cost of serving very large industrial electric loads; risk, incentives and rate design.

265. **Ark.** **PSC** 10-101-R, Rulemaking re self-directed energy efficiency for large customers; National Audubon Society and Audubon Arkansas. July 2011.

Structuring energy-efficiency programs for large customers.

266. **Okla. Corporation Commission** PUD 201100077, current and pending federal regulations and legislation affecting Oklahoma utilities; Sierra Club. Comments July, October 2011; presentation July 2011.

Challenges facing Oklahoma coal plants; efficiency, renewable and conventional resources available to replace existing coal plants; integrated environmental compliance planning.

267. **Nevada** **PUC** 11-08019, integrated analysis of resource acquisition, Sierra Club. Comments, September 2011; hearing, October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

268. **La.** **PSC** R-30021, Louisiana integrated-resource-planning rules; Alliance for Affordable Energy. Comments, October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

269. **Okla. Corporation Commission** PUD 201100087, Oklahoma Gas and Electric Company electric rates; Sierra Club. November 2011.

Resource monitoring and acquisition. Benefits to ratepayers of energy conservation and renewables. Supply planning

270. **Ky. PSC** 2011-00375, Kentucky utilities' purchase and construction of power plants; Sierra Club and National Resources Defense Council. December 2011.

Assessment of resources, especially renewables. Treatment of risk. Treatment of future environmental costs.

271. **N.S. UARB** 04819, demand-side-management plan of Efficiency Nova Scotia; Nova Scotia Consumer Advocate. May 2012.

Avoided costs. Allocation of costs. Reporting of bill effects.

272. **Kansas Corporation Commission** 12-GIMX-337-GIV, utility energy-efficiency programs; The Climate and Energy Project. June 2012.

Cost-benefit tests for energy-efficiency programs. Collaborative program design.

273. **N.S. UARB** 04862, Port Hawksbury load-retention mechanism; Nova Scotia Consumer Advocate. June 2012.

Effect on ratepayers of proposed load-retention tariff. Incremental capital costs, renewable-energy costs, and costs of operating biomass cogeneration plant.

274. **Utah PSC** 11-035-200, Rocky Mountain Power Rates; Utah Office of Consumer Council. June 2012.

Cost allocation. Estimation of marginal customer costs.

275. **Ark. PSC** 12-008-U, environmental controls at Southwestern Electric Power Company's Flint Creek plant; Sierra Club. Direct, June 2012; rebuttal, August 2012; further, March 2013.

Costs and benefits of environmental retrofit to permit continued operation of coal plant, versus other options including purchased gas generation, efficiency, and wind. Fuel-price projections. Need for transmission upgrades.

276. **U.S. EPA** EPA-R09-OAR-2012-0021, air-quality implementation plan; Sierra Club. September 2012.

Costs, financing, and rate effects of Apache coal-plant scrubbers. Relative incomes in service territories of Arizona Coop and other utilities.

277. **Arkansas PSC** Docket No. 07-016-U; Entergy Arkansas' integrated resource plan; Audubon Arkansas. Comments, September 2012.

Estimation of future gas prices. Estimation of energy-efficiency potential. Screening of resource decisions. Wind costs.

278. **Vt. PSB** 7862, Entergy Nuclear Vermont and Entergy Nuclear Operations petition to operate Vermont Yankee; Conservation Law Foundation. October 2012.

Effect of continued operation on market prices. Value of revenue-sharing agreement. Risks of underfunding decommissioning fund.

279. **Man. PUB** 2012–13 GRA, Manitoba Hydro rates; Green Action Centre. November 2012.

Estimation of marginal costs. Fuel switching.

280. **N.S. UARB** M05339, Capital Plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Economic and financial modeling of investment. Treatment of AFUDC.

281. **N.S. UARB** M05416, South Canoe wind project of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Revenue requirements. Allocation of tax benefits. Ratemaking.

282. **N.S. UARB** 05419; Maritime Link transmission project and related contracts, Nova Scotia Consumer Advocate and Small Business Advocate. Direct, April 2013; supplemental (with Seth Parker), November 2013.

Load forecast, including treatment of economy energy sales. Wind power cost forecasts. Cost effectiveness and risk of proposed project. Opportunities for improving economics of project.

283. **Ont. Energy Board** 2012-0451/0433/0074, Enbridge Gas Greater Toronto Area project; Green Energy Coalition. June 2013, revised August 2013.

Estimating gas pipeline and distribution costs avoidable through gas DSM and curtailment of electric generation. Integrating DSM and pipeline planning.

284. **N.S. UARB** 05092, tidal-energy feed-in-tariff rate; Nova Scotia Consumer Advocate. August 2013.

Purchase rate for test and demonstration projects. Maximizing benefits under rate-impact caps. Pricing to maximize provincial advantage as a hub for emerging tidal-power industry.

285. **N.S. UARB** 05473, Nova Scotia Power 2013 cost-of-service study; Nova Scotia Consumer Advocate. October 2013.

Cost-allocation and rate design.

286. **B.C. Utilities Commission** 3698715 & 3698719; performance-based ratemaking plan for FortisBC companies; British Columbia Sustainable Energy Association and Sierra Club British Columbia. Direct (with John Plunkett), December 2013.

Rationale for enhanced gas and electric DSM portfolios. Correction of utility estimates of electric avoided costs. Errors in program screening. Program potential. Recommended program ramp-up rates.

287. **Man. PUB** 2014, need for and alternatives to proposed hydro-electric facilities; Green Action Centre. Evidence (with Wesley Stevens) February 2014.

Potential for fuel switching, DSM, and wind to meet future demand.

288. **Utah PSC** 13-035-184, Rocky Mountain Power Rates; Utah Office of Consumer Services. May 2014.

Class cost allocation. Classification and allocation of generation plant and purchased power. Principles of cost-causation. Design of backup rates.

289. **Minn. PSC** E002/GR-13-868, Northern States Power rates; Clean Energy Intervenors. Direct, June 2014; rebuttal, July 2014; surrebuttal, August 2014.

Inclining-block residential rate design. Rationale for minimizing customer charges.

290. **Cal. PUC** Rulemaking 12-06-013, electric rates and rate structures; Natural Resources Defense Council. September 2014.

Redesigning residential rates to simplify tier structure while maintaining efficiency and conservation incentives. Effect of marginal price on energy consumption. Realistic modeling of Consumer price response. Benefits of minimizing customer charges.

291. **Md. PSC** 9361, proposed merger of PEPCo Holdings into Exelon; Sierra Club and Chesapeake Climate Action Network. Direct, December 2014; surrebuttal, January 2015.

Effect of proposed merger on Consumer bills, renewable energy, energy efficiency, and climate goals.

292. **N.S. UARB** M06514, 2015 capital-expenditure plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2015.

Economic evaluation of proposed projects. Treatment of AFUDC, overheads, and replacement costs of lost generation. Computation of rate effects of spending plan.

293. **N.S. UARB** M06733, supply agreement between Efficiency One and Nova Scotia Power; Nova Scotia Consumer Advocate. January 2015.

Avoided costs. Cost-effectiveness screening of DSM. Portfolio design. Affordability and bill effects.

294. **Md. PSC** 9153 et al., Maryland energy-efficiency programs; Maryland Office of People's Counsel. January 2015.

Costs avoided by demand-side management. Demand-reduction-induced price effects.

295. **Québec** Régie de L'énergie R-3876-2013 phase 1, Gaz Métro cost allocation and rate structure; Regroupement des organismes environnementaux en énergie and Union des consommateurs. February 2015

Classification of the area-spanning system; minimum system and more realistic approaches. Allocation of overhead, energy-efficiency, gas-supply, engineering-and-planning, and billing costs.

296. **Ky. PSC** 2014-00371, Kentucky Utilities Company electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

297. **Ky. PSC** 2014-00372, Louisville Gas and Electric Company electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

298. **Penn. PUC** P-2014-2459362, Philadelphia Gas Works DSM, universal-service, and energy-conservation plans; Philadelphia Gas Works. Direct, May 2015; Rebuttal, July 2015.

Avoided costs. Recovery of lost margin.

299. **Mich. PSC** U-17767, DTE Electric Company rates; Michigan Environmental Council, Sierra Club, and Natural Resource Defense Council. May 2015.

Cost effectiveness of pollution-control retrofits versus retirements. Market prices. Costs of alternatives.

ACRONYMS AND INITIALISMS

APS	Alleghany Power
ASLB	Atomic Safety and Licensing Board
BEP	Board of Environmental Protection
BPU	Board of Public Utilities
BRC	Board of Regulatory Commissioners
CMP	Central Maine Power
DER	Department of Environmental Regulation
DPS	Department of Public Service
DQE	Duquesne Light
DPUC	Department of Public Utilities Control
DSM	Demand-Side Management
DTE	Department of Telecommunications and Energy
EAB	Environmental Assessment Board
EFSB	Energy Facilities Siting Board
EFSC	Energy Facilities Siting Council
EUB	Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LRAM	Lost-Revenue-Adjustment Mechanism
NARUC	National Association of Regulatory Utility Commissioners
NEPOOL	New England Power Pool
NRC	Nuclear Regulatory Commission
OCA	Office of Consumer Advocate
PSB	Public Service Board
PBR	Performance-based Regulation
PSC	Public Service Commission
PUC	Public Utility Commission
PUB	Public Utilities Board
PURPA	Public Utility Regulatory Policy Act
SCC	State Corporation Commission
UARB	Utility and Review Board
USAEE	U.S. Association of Energy Economists
UTC	Utilities and Transportation Commission

PLC 7/28/2015

SENDOUT provides detailed dispatch optimization and assesses gas portfolio cost, revenue, and reliability while considering operational constraints and economic parameters

Overview

SENDOUT® is used by energy companies as the foundation for gas supply planning and portfolio optimization processes. ABB's gas analytics solution set includes a detailed supply portfolio optimization module, which incorporates scenario and stochastic analysis and an asset valuation module, which simulates forward curves and related trading behavior.

The software suite provides an assessment of gas portfolio costs, reliability, risks, and opportunities, revealing the impact of potential operating, weather, and price conditions.

Ultimately, SENDOUT is an integrated platform for short-term through long-term portfolio optimization, decision evaluation, and asset valuation. SENDOUT supports an industry proven, comprehensive, defendable, and prudent gas supply planning and asset valuation analytical process.

The solution is comprised of two integrated components:

Optimization Module – provides gas supply portfolio optimization, contract sizing, and scenario analysis

Asset Valuation Module – simulates market trading behavior and determines intrinsic/extrinsic value of gas assets Gas portfolio network model

Optimization Module

The SENDOUT model harnesses powerful linear programming and mixed integer programming (LP/MIP) engines for scenario analysis and physical portfolio dispatch optimization. The objective function seeks to minimize total gas supply system costs, while simultaneously maximizing revenue opportunities associated with incremental markets, capacity release, and off-system sales transactions. SENDOUT simultaneously evaluates thousands of time-dependent economic and operational constraints across the study period.

This assures that short-term dispatch decisions are consistent with out-term requirements and targets, such as storage inventory targets, ratchets, and contract minimum take requirements.

Key Benefits

- Supports a proven and defendable resource planning process
- Evaluates multiple decision criterion simultaneously
- Provides optimization of portfolio utilization and costs within operating constraints
- Maximizes financial results by managing weather and price risks
- Increases revenues by assessing capacity release and sales opportunities
- Reduces regulatory costs through improved compliance and procedures
- Helps sustain a consistent and repeatable planning methodology
- Compares multiple scenario results and dispatch decisions side-by-side
- Improves analytical quality with a sophisticated, comprehensive, and flexible approach to gas supply planning

SENDOUT Process Flow

The Optimization Module provides two optimization types:

Standard Optimization – determines the optimal use of the existing portfolio of resources to meet projected load requirements in a least cost manner based on variable costs only (considers fixed costs sunk).

Resource Mix Optimization – evaluates and optimally sizes potential contracts and sales opportunities, while meeting load requirements in a least cost manner based on the fixed and variable costs associated with optional resources.

ABB's comprehensive gas planning solution differs from traditional portfolio analysis. Traditional analysis typically relies on a few scenarios as a proxy to support important decisions.

For example, with respect to weather (demand), relying on normal, design cold, and design warm provides a limited view of the portfolio under those specific conditions. In contrast, our solution not only supports deterministic scenario analysis, but also considers the probability and implications of a distribution of weather and price conditions, which may fall between and outside the range of the typical planning scenarios.

The probabilistic approach provides additional risk metrics for better resource decisions, including expected value, variability, and probability.

Asset Valuation Module

Asset Valuation determines the potential market value or liability associated with a gas asset, typically storage. SENDOUT determines the intrinsic and extrinsic value of an asset by leveraging Principal Component Analysis and Rolling Intrinsic Optimization. SENDOUT simulates day-to-day trading and scheduling behavior to evaluate arbitrage opportunities between futures, term, and take-or-pay contracts, spot and balance of month procurement decisions.

Daily transactions are executed without perfect knowledge of future price strips. Thus, each day new transactions are executed considering previously executed positions, which may be committed or unwound to take advantage of new price arbitrage opportunities. Market prices and related transactions are simulated daily and discounted cash flows are calculated to represent the value of the asset(s).

SENDOUT Software Suite Features

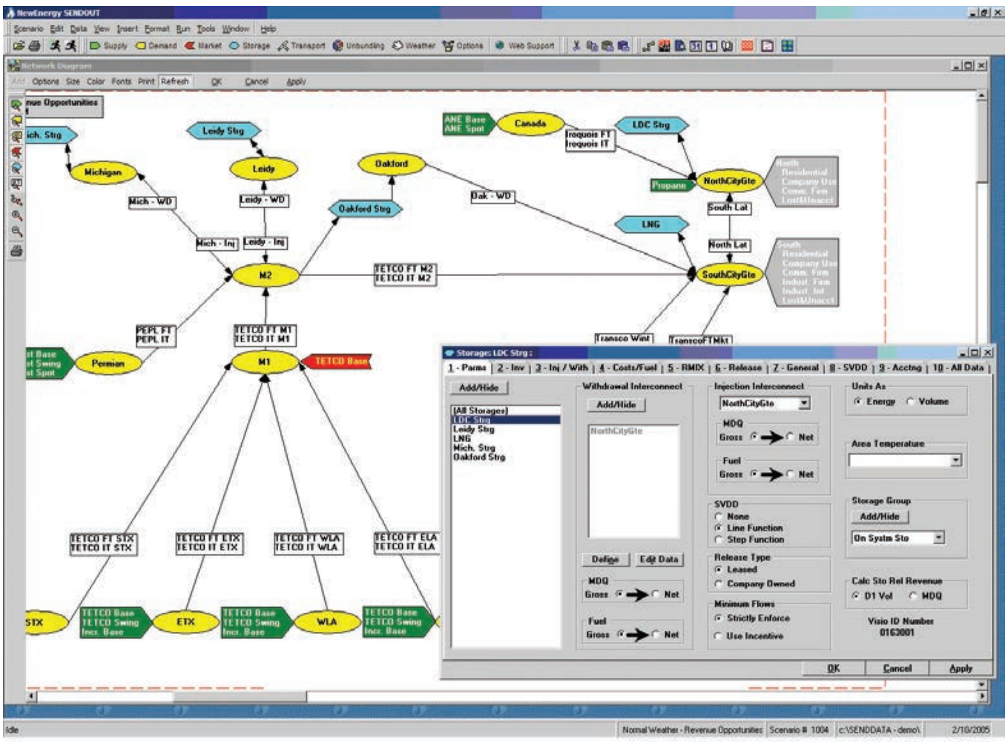
– Easy scenario and simulation creation with minimal data manipulation
– Fast simulation and optimization run times
– User-friendly, flexible, and intuitive interface specifically designed for the gas industry
– A comprehensive list of data items and parameters to accurately model gas system intricacies
– Flexible data management including various input options and integration with Microsoft Excel
– Customizable reports/graphs and seamless integration to Microsoft Excel, Access, Visio, Text, or HTML files
– Network diagramming and portfolio schematic visualization feature
– Over 100 comprehensive System Reports & Custom Reporting tools
– Dispatch and Gas Cost Forecasts

About ABB

ABB provides industry leading software and deep domain expertise to help the world's most asset intensive industries such as energy, utilities and mining solve their biggest challenges, from plant level, to regional network scale, to global fleet-wide operations.

Our enterprise software portfolio offers an unparalleled range of solutions for asset performance management, operations and workforce management, network control and energy portfolio management to help customers reach new levels of efficiency, reliability, safety and sustainability. We are constantly researching and incorporating the latest technology innovations in areas such as mobility, analytics and cloud computing.

We provide unmatched capabilities to integrate information technologies (IT) and operational technologies (OT) to provide complete solutions to our customers' business problems.



SENDOUT Model Run
Design Year 2012 / 2013
Existing Portfolio with HubLine

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	1073: 2013Q3 MA DY No AIM IR 8-29-13	Ventyx	Page 1 ,┐┐												
2	- Draw 0	SENDOUT® Version 14.1.0 REP 1	26-Nov-2013 ,┐┐												
3		Report 1	17:46:07 ,┐┐												
4															
5	NOV 2012 thru OCT 2013	USD (000)													
6															
7		Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod							
8		---------------------		---------------------		---------------------		-----------------							
9		Commodity Cost	515544	Injection Cost	4621	Transportation Cost	12225	JAN 14	2013						
10		Penalty Cost	0	Withdrawal Cost	285	Other Variable Cost	0	System Served	1286.183						
11		Other Variable Cost	0	Carrying Cost	0			System Unserved	0						
12				Other Variable Cost	1			Total	1286.183						
13		Total Variable	515544	Total Variable	4907	Total Variable	12225								
14															
15		Demand/Reservation Co	23703	Demand Cost	12780	Demand Cost	160529								
16		Other Fixed Cost	0	Other Fixed Cost	4078	Other Fixed Cost	99								
17		Total Fixed	23703	Total Fixed	16858	Total Fixed	160628								
18															
19		Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0								
20		Net Supply Cost	539247	Net Storage Cost	21765	Net Trans Cost	172853	Total Gas Cost	733865						
21								Total Revenue	0						
22								Net Cost	733865						
23															
24		Avg Cost of Served Demand	5.675	USD/DT	Avg Cost of Gas Purc		3.99	USD/DT							
25		(System Cost/Served Dem.)			(Supply Cost/LDC Pur										
26															
27		Demand Summary													
28			Demand	DSM	Net	Imbal.	Demand				Revenue	Peak	Peak		
29		Class	Before DSM	Impact	Demand	Served	After Unb.	Served	Unservec			Served	Unserved		
30															
31		BOS-N	38321.626	0	38321.626	0	38321.626	38321.626	0	0	381.057	0			
32		BOS-S	57482.438	0	57482.438	0	57482.438	57482.438	0	0	571.586	0			
33		ESX	7254.033	0	7254.033	0	7254.033	7254.033	0	0	70.547	0			
34		LOW	14431.806	0	14431.806	0	14431.806	14431.806	0	0	148.897	0			
35		CAP	11819.949	0	11819.949	0	11819.949	11819.949	0	0	114.096	0			
36															
37		Total	129309.852	0	129309.852	0	129309.852	129309.852	0	0	1286.183	0			
38		Supply Summary													
39															
40			Total	Max		Take Under	Take Under	Av Comm	Total	Total	Net	Average			
41		Source	Take	Take	Surplus	Daily Min	Other Min	Cost	Var Cost	Fix Cost	Cost	Net Cost			
42		Niagara	1019.292	4745	3725.708			3.9378	4014	0	4014	3.9378			
43		Dawn	1765.021	6570	4804.979			3.8108	6726	0	6726	3.8108			
44		Waddington	3797.047	13140	9342.953			6.8901	26162	0	26162	6.8901			
45		Dracut	2226.604	14696	12469.396			6.3011	14030	0	14030	6.3011			
46		Wharton	365.542	2737.5	2371.958			4.1622	1521	0	1521	4.1622			
47		TETCO Gulf	29318.059	55721.219	26403.16			3.4255	100428	0	100428	3.4255			
48		TGPZ4	30114.756	35192	5077.244			3.3504	100896	0	100896	3.3504			
49		TGPZ4 Cold	131.07	38690	38558.93			4.1348	542	0	542	4.1348			
50		TGP2025Gulf	5086.651	14600	9513.349			3.4213	17403	0	17403	3.4213			
51		TGP2062Gulf	8486.776	30660	22173.224			3.3848	28726	0	28726	3.3848			
52		TGP64023Gulf	13770.975	19345	5574.025			3.5118	48362	0	48362	3.5118			
53		TGP64024Gulf	16368.141	23725	7356.859			3.5086	57429	0	57429	3.5086			
54		TGP90623Gulf	2295.645	5110	2814.355			3.4668	7958	0	7958	3.4668			
55		TXG29962Gulf	6.661	5110	5103.339			3.38	23	0	23	3.38			
56		M3	11541.743	100010	88468.257			3.9785	45919	0	45919	3.9785			
57		M3 Cold	0	100010	100010			0	0	0	0	0			
58		Distrigas	5746.695	5746.695	0			4.7564	27333	23378	50711	8.8244			
59		Beverly	796.733	16790	15993.267			10.3987	8285	0	8285	10.3987			
60		FVS217	61.8	61.8	0			16.093	995	325	1320	21.3562			

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
61		Southbridge	11.672	11.672	0			14.6713	171	0	171	14.6713			
62		Norwood	14.24	14.24	0			14.6713	209	0	209	14.6713			
63		DTI Lebanon	1752.434	4847.2	3094.766			3.3834	5929	0	5929	3.3834			
64		OPR BOS	0.02	364635	364634.98			25.808	1	0	1	25.808			
65		OPR ESX	0	364635	364635			0	0	0	0	0			
66		OPR LOW	466.364	364635	364168.636			26.763	12481	0	12481	26.763			
67		OPR CAP	0	364635	364635			0	0	0	0	0			
68		DracutHess	0	0	0			0	0	0	0	0			
69		BevRepsol	0	0	0			0	0	0	0	0			
70		BevHess	0	0	0			0	0	0	0	0			
71		AIM	0	0	0			0	0	0	0	0			
72															
73		Total	135143.942						515544	23703	539247				
74		Storage Summary													
75															
76			Starting	%	Total	Total	NetInv	Inj	Final	%	With.	Diff in	Start	Final	Diff in
77		Storage	Balance	Full	Inj.	With.	Adj.	Fuel	Balance	Full	Fuel	Balance	Value	Value	Value
78		Honeoye	981.12	100	523.434	523.434	0	0	981.12	100	0	0	4135	3833	-301
79		NFLO01734	930.45	100	207.164	204.699	0	2.465	930.45	100	2.682	0	3921	3810	-111
80		FSMA524	1068.434	98	501.619	466.95	0	7.273	1095.83	100	0	27.396	4503	4335	-168
81		FSMA527	6344.774	98	2886.283	2681.745	0	41.851	6507.46	100	0	162.687	26739	25797	-942
82		GSS-TE60020	4698.132	100	3134.017	3053.786	0	80.231	4698.132	100	0	0	20000	19079	-921
83		GSS300114	222.2	100	148.225	144.43	0	3.795	222.2	100	0	0	946	902	-44
84		GSS-NS300115	10.4	100	6.938	6.76	0	0.178	10.4	100	0	0	44	42	-2
85		GSS-TE600008	823.529	100	549.357	535.294	0	14.064	823.529	100	0	0	3506	3344	-161
86		SS-1400225	4814.639	97	2672.343	2525.909	0	22.982	4938.091	100	80.829	123.452	20496	19852	-644
87		SS-1400200	481.149	98	254.352	239.828	0	2.187	493.486	100	7.674	12.337	2048	1987	-61
88		NGLNG006	1130.218	100	1132.68	1215.76	0	0	1047.138	93	0	-83.08	6346	5635	-711
89		BOS-NLYNN	937.364	100	1124.951	1124.951	0	0	937.364	100	0	0	5263	4531	-733
90		BOS-NSALEM	936.389	100	1069.135	1069.135	0	0	936.389	100	0	0	5258	4560	-698
91		ESXHAVERHILL	332.8	100	314.504	397.704	0	0	249.6	75	0	-83.2	1869	1362	-507
92		LOWTEWKSBURY	0	0	626.209	44.225	0	0	581.984	67	0	581.984	0	2818	2818
93		LOWWESTFORD	3.382	100	66.014	66.014	0	0	3.382	100	0	0	19	83	64
94		BOS-SCOMMPT	1068.434	100	1349.645	1349.645	0	0	1068.434	100	0	0	5999	5136	-863
95		CAPEWAREHAM	6.656	100	0.702	0.702	0	0	6.656	100	0	0	37	38	1
96		CAPEYARMOUTH	143.832	100	62.855	62.855	0	0	143.832	100	0	0	808	821	13
97															
98		Total	24933.901	95	16630.427	15713.82	0	175.026	25675.48	98	91.185	741.576	111938	107967	-3971
99		Transportation Summary													
100															
101			Total	Fuel						Cap Rel		Average			
102		Segment	Flow	Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Revenue	Net Cost	Net Cost			
103		TGP256	781.186	7.109	774.077	3844.545	3070.468	70	940	0	1010	1.2931			
104		TGP90618	144.829	1.343	143.486	356.24	212.754	13	87	0	100	0.6909			
105		TGP90622	93.276	0.864	92.412	235.425	143.013	8	58	0	66	0.7066			
106		UNIM12197	932.627	9.271	923.356	3211.27	2287.914	0	260	0	260	0.2786			
107		UNIM12198	628.04	6.272	621.767	2240.005	1618.238	0	181	0	181	0.2886			
108		UNIM12199	204.355	2.045	202.31	746.425	544.115	0	60	0	60	0.2955			
109		TCP29601	932.772	12.049	920.723	3175.865	2255.142	19	1176	0	1196	1.282			
110		TCP29602	610.942	8.001	602.941	2215.55	1612.609	13	821	0	833	1.3641			
111		TCP29603	203.72	2.65	201.069	738.395	537.326	4	274	0	278	1.3634			
112		IGT42001	5277.231	6.709	5270.523	16838.545	11568.022	25	3652	0	3677	0.6968			
113		IGT48001	244.549	0.252	244.297	2215.55	1971.253	1	481	0	482	1.9698			
114		TGP95343	1264.849	12.062	1252.787	3139	1886.213	113	768	0	881	0.6962			
115		TGP95344BOS	1568.562	14.931	1553.632	5475	3921.368	140	1339	0	1479	0.9429			
116		TGP95344MEN	2198.835	21.492	2177.343	7300	5122.657	196	1786	0	1981	0.9011			
117		TGP95347	290.498	2.699	287.799	730	442.201	26	179	0	204	0.7039			
118		TGP95348MEN	192.076	1.84	190.236	2190	1999.764	17	536	0	553	2.8779			
119		AGT9221	4495.452	45.73	4449.722	7289.05	2839.328	8	1465	0	1473	0.3277			
120		AGT9227	1474.446	14.446	1460	1460	0	3	293	0	296	0.2008			

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
121		AGT93203CMEN	737.223	7.223	730	730	0	9	154	0	164	0.2219			
122		TGP64023BG	7358.912	286.726	7072.186	11434.355	4362.169	13	13837	0	13850	1.882			
123		TGP64023MEN	4296.899	166.953	4129.946	7076.62	2946.674	7	0	0	7	0.0017			
124		TGP64023Stor	1868.393	60.865	1807.528	18510.975	16703.447	3	0	0	3	0.0017			
125		TGP64023HON	246.771	8.95	237.821	18510.975	18273.154	0	0	0	0	0.0017			
126		TGP64024BG	9924.832	386.354	9538.478	15638.425	6099.947	17	16912	0	16929	1.7057			
127		TGP64024MEN	4297.967	167.505	4130.463	6986.1	2855.637	7	0	0	7	0.0017			
128		TGP64024Stor	1848.892	60.23	1788.663	22624.525	20835.862	3	0	0	3	0.0017			
129		TGP64024HON	296.449	10.836	285.613	22624.525	22338.912	1	0	0	1	0.0017			
130		AGT510364	3920.866	40.006	3880.86	13870	9989.14	50	2997	0	3048	0.7774			
131		AGT510365	3880.86	32.773	3848.087	13870	10021.913	7	485	0	492	0.1269			
132		AGT510366	3848.087	32.429	3815.658	13870	10054.342	7	3815	0	3821	0.9931			
133		TGP2025LH	5086.651	190.792	4895.859	13184.165	8288.306	1621	8995	0	10615	2.0869			
134		TGP2062LH	8486.776	312.415	8174.361	29260.59	21086.229	2673	19753	0	22425	2.6424			
135		TGP2062Z4BG	5174.684	64.455	5110.229	5163.655	53.426	611	3486	0	4096	0.7916			
136		TGP90623LH	2295.645	85.077	2210.568	4879.685	2669.117	722	3287	0	4009	1.7464			
137		TGP90623Z4EG	840.442	10.461	829.981	861.035	31.054	99	580	0	679	0.8081			
138		NFLN01733IN	208.289	1.125	207.164	975.626	768.462	3	0	0	3	0.0152			
139		NFLN01733OUT	202.017	1.535	200.482	936.653	736.171	3	281	0	284	1.4082			
140		TGP623	15002.743	186.517	14816.226	15215.755	399.529	1770	4247	0	6017	0.4011			
141		TGP2029	2282.578	28.57	2254.008	2738.96	484.952	269	764	0	1034	0.4529			
142		TGP2025Z4FSM	1878.591	2.153	1876.438	2326.875	450.437	18	1587	0	1606	0.8548			
143		TGP10778	3706.836	45.633	3661.203	5870.295	2209.092	438	1638	0	2076	0.5601			
144		TGP20241Z4	2114.519	26.125	2088.394	2510.105	421.711	250	690	0	940	0.4445			
145		TGP20241Z5	523.434	4.763	518.671	2244.75	1726.079	47	559	0	606	1.1578			
146		TGP90617EG	1633.954	20.267	1613.687	1887.78	274.093	193	527	0	720	0.4405			
147		TGP90620EG	960.657	11.743	948.914	1485.185	536.271	113	415	0	528	0.5496			
148		TET800285	13501.866	832.306	12669.561	32031.305	19361.744	871	15263	0	16134	1.1949			
149		TET800286	5349.367	327.218	5022.149	11904.84	6882.691	340	5881	0	6220	1.1628			
150		TET800313	1629.396	99.701	1529.695	3602.185	2072.49	104	1726	0	1830	1.123			
151		TET800469	1706.803	104.546	1602.257	3916.815	2314.558	109	1935	0	2043	1.1972			
152		TET DTI Stor	4047.279	208.742	3838.536	51455.145	47616.609	212	0	0	212	0.0525			
153		TET SS-1 Sto	3083.348	156.653	2926.696	20320.645	17393.949	152	0	0	152	0.0494			
154		AGT92100	18.573	0.19	18.383	37.96	19.577	0	8	0	8	0.4443			
155		AGT93002CR	7783.984	80.703	7703.28	13513.671	5810.391	100	3444	0	3544	0.4554			
156		AGT93002EA	14697.129	154.292	14542.837	30242.316	15699.479	189	7366	0	7555	0.5141			
157		AGT93003ECR	2767.31	28.736	2738.574	5055.225	2316.651	36	1269	0	1304	0.4713			
158		AGT93203CLAM	1303.977	13.767	1290.21	3602.185	2311.975	17	760	0	777	0.596			
159		AGT933003	489.356	4.984	484.372	811.03	326.658	1	261	0	262	0.535			
160		AGT934001	4294.91	44.031	4250.879	7581.415	3330.536	8	2950	0	2958	0.6887			
161		AGT98002C	767.603	8.234	759.369	2378.365	1618.996	10	565	0	574	0.7484			
162		TXG29962	6.661	0.206	6.455	4847.2	4840.745	0	1523	0	1523	228.6741			
163		DTI100015	1758.889	50.128	1708.761	4736.97	3028.209	40	655	0	695	0.395			
164		TET800287	1855.835	46.019	1809.816	7808.81	5998.994	39	1440	0	1480	0.7972			
165		AGT99058LAM	4863.802	51.107	4812.695	14443.415	9630.72	63	3049	0	3112	0.6398			
166		TRA6425	336.364	2.186	334.178	2312.275	1978.097	51	314	0	365	1.0855			
167		TRA6428	29.178	0.19	28.988	210.24	181.252	4	29	0	33	1.1308			
168		AGT93203CCEN	26.153	0.285	25.868	210.605	184.737	0	44	0	45	1.7129			
169		AGT99058CEN	337.013	3.65	333.364	2312.275	1978.911	4	488	0	492	1.4613			
170		TGP31898BG	322.187	1.224	320.963	2555	2234.037	12	179	0	191	0.5919			
171		TGP31898EG	732.267	2.785	729.482	5913	5183.518	27	414	0	441	0.6021			
172		TGP31898CG	1172.149	4.454	1167.695	7300	6132.305	43	511	0	554	0.4727			
173		AGT510025	77.633	0.854	76.779	9125	9048.221	0	3010	0	3010	38.7686			
174		AGT510100	719.1	7.895	711.205	7300	6588.795	1	1678	0	1679	2.3354			
175		DTI700049	144.43	4.116	140.314	335.522	195.208	3	47	0	50	0.3461			
176		TET331009	3053.786	96.4	2957.386	10918.975	7961.589	97	2361	0	2458	0.8048			
177		TET331700	403.289	15.092	388.197	1100.84	712.643	17	238	0	255	0.6316			
178		TET331800	132.005	4.94	127.065	359.525	232.46	5	81	0	87	0.656			
179		TET800400	0	0	0	848.99	848.99	0	245	0	245	0			
180		AGT9B100	2977.416	31.486	2945.93	6350.647	3404.717	38	2305	0	2343	0.7869			

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
181		AGT9B101C	361.04	3.862	357.178	849.607	492.429	5	308	0	313	0.8668			
182		AGT99012	1215.76	13.076	1202.685	5429.878	4227.193	16	917	0	932	0.7667			
183		IP N to S	14273.111	0	14273.111	21900	7626.889	0	0	0	0	0			
184		TGPCG>BOS	0	0	0	364635	364635	0	0	0	0	0			
185		TGPCG>COL	0	0	0	364635	364635	0	0	0	0	0			
186		TGPCG>ESX	0	0	0	364635	364635	0	0	0	0	0			
187		BG LNG North	1363.042	0	1363.042	364635	363271.958	0	0	0	0	0			
188		BG LNG South	2180.689	0	2180.689	364635	362454.311	0	0	0	0	0			
189		AIM Hub BG	0	0	0	0	0	0	0	0	0	0			
190		AIM Hub CG	0	0	0	0	0	0	0	0	0	0			
191		AIM	0	0	0	0	0	0	0	0	0	0			
192															
193		Total		4826.303				12225	160628		172853	0.8068			

SENDOUT Model Run
Design Year 2012 / 2013
Portfolio with AIM Replacing HubLine

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	1074: 2013Q3 MA DY AIM IR 8-29-13	Ventyx	Page 1 ƒ┐┐												
2	- Draw 0	SENDOUT® Version 14.1.0 REP 1 26-Nov-2013 ƒ┐┐													
3		Report 1	17:50:38 ƒ┐┐												
4															
5	NOV 2012 thru OCT 2013	USD (000)													
6															
7		Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod							
8		---------------------		---------------------		---------------------		-----------------							
9		Commodity Cost	496795	Injection Cost	4035	Transportation Cost	11784	JAN 14	2013						
10		Penalty Cost	2108	Withdrawal Cost	288	Other Variable Cost	0	System Served	1286.183						
11		Other Variable Cost	0	Carrying Cost	0			System Unserved	0						
12				Other Variable Cost	1			Total	1286.183						
13		Total Variable	498903	Total Variable	4323	Total Variable	11784								
14															
15		Demand/Reservation Co	23703	Demand Cost	12780	Demand Cost	217161								
16		Other Fixed Cost	0	Other Fixed Cost	4078	Other Fixed Cost	99								
17		Total Fixed	23703	Total Fixed	16858	Total Fixed	217260								
18															
19		Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0								
20		Net Supply Cost	522606	Net Storage Cost	21181	Net Trans Cost	229045	Total Gas Cost	772832						
21								Total Revenue	0						
22								Net Cost	772832						
23															
24		Avg Cost of Served Demand	5.977	USD/DT	Avg Cost of Gas Purc	3.856	USD/DT								
25		(System Cost/Served Dem.)			(Supply Cost/LDC Pu										
26															
27		Demand Summary													
28			Demand	DSM	Net	Imbal.	Demand			Revenue	Peak	Peak			
29		Class	Before DSM	Impact	Demand	Served	After Unb.	Served	Unservec		Served	Unserved			
30															
31		BOS-N	38321.626	0	38321.626	0	38321.626	38321.626	0	0	381.057	0			
32		BOS-S	57482.438	0	57482.438	0	57482.438	57482.438	0	0	571.586	0			
33		ESX	7254.033	0	7254.033	0	7254.033	7254.033	0	0	70.547	0			
34		LOW	14431.806	0	14431.806	0	14431.806	14431.806	0	0	148.897	0			
35		CAP	11819.949	0	11819.949	0	11819.949	11819.949	0	0	114.096	0			
36															
37		Total	129309.852	0	129309.852	0	129309.852	129309.852	0	0	1286.183	0			
38		Supply Summary													
39															
40			Total	Max		Take Under	Take Under	Av Comm	Total	Total	Net	Average			
41		Source	Take	Take	Surplus	Daily Min	Other Min	Cost	Var Cost	Fix Cost	Cost	Net Cost			
42		Niagara	795.347	4745	3949.653			3.8919	3095	0	3095	3.8919			
43		Dawn	1662.336	6570	4907.664			3.8013	6319	0	6319	3.8013			
44		Waddington	2706.898	13140	10433.102			3.4775	9413	0	9413	3.4775			
45		Dracut	1740.8	14696	12955.2			6.3087	10982	0	10982	6.3087			
46		Wharton	182.899	2737.5	2554.601			4.2176	771	0	771	4.2176			
47		TETCO Gulf	28776.245	55721.219	26944.974			3.424	98530	0	98530	3.424			
48		TGPZ4	30114.756	35192	5077.244			3.3504	100896	0	100896	3.3504			
49		TGPZ4 Cold	99.296	38690	38590.704			4.0816	405	0	405	4.0816			
50		TGP2025Gulf	5086.651	14600	9513.349			3.4213	17403	0	17403	3.4213			
51		TGP2062Gulf	8106.648	30660	22553.352			3.3826	27422	0	27422	3.3826			
52		TGP64023Gulf	14185.54	19345	5159.46			3.506	49735	0	49735	3.506			
53		TGP64024Gulf	15871.848	23725	7853.152			3.5131	55759	0	55759	3.5131			
54		TGP90623Gulf	2293.549	5110	2816.451			3.4669	7951	0	7951	3.4669			
55		TXG29962Gulf	6.661	5110	5103.339			3.38	23	0	23	3.38			
56		M3	4251.528	100010	95758.472			3.9841	16938	0	16938	3.9841			
57		M3 Cold	0	100010	100010			0	0	0	0	0			
58		Distrigas	5209.09	5746.695	537.605		537.605	4.7347	26772	23378	50150	9.6273			
59		Beverly	0	16790	16790			0	0	0	0	0			
60		FVS217	0	61.8	61.8			0	0	325	325	0			

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
61		Southbridge	0	11.672	11.672			0	0	0	0	0			
62		Norwood	0	14.24	14.24			0	0	0	0	0			
63		DTI Lebanon	1752.434	4847.2	3094.766			3.3834	5929	0	5929	3.3834			
64		OPR BOS	0	364635	364635			0	0	0	0	0			
65		OPR ESX	0	364635	364635			0	0	0	0	0			
66		OPR LOW	433.715	364635	364201.285			26.8349	11639	0	11639	26.8349			
67		OPR CAP	0	364635	364635			0	0	0	0	0			
68		DracutHess	0	0	0			0	0	0	0	0			
69		BevRepsol	0	0	0			0	0	0	0	0			
70		BevHess	0	0	0			0	0	0	0	0			
71		AIM	12257.821	37230	24972.179			3.9908	48919	0	48919	3.9908			
72															
73		Total	135534.063				537.605		498903	23703	522606				
74		Storage Summary													
75															
76			Starting	%	Total	Total	NetInv	Inj	Final	%	With.	Diff in	Start	Final	Diff in
77		Storage	Balance	Full	Inj.	With.	Adj.	Fuel	Balance	Full	Fuel	Balance	Value	Value	Value
78		Honeoye	981.12	100	485.683	485.683	0	0	981.12	100	0	0	4135	3850	-285
79		NFLO01734	930.45	100	179.073	176.942	0	2.131	930.45	100	2.318	0	3921	3823	-98
80		FSMA524	1068.434	98	496.58	461.984	0	7.2	1095.83	100	0	27.396	4503	4338	-165
81		FSMA527	6344.774	98	2886.283	2681.745	0	41.851	6507.46	100	0	162.687	26739	25797	-942
82		GSS-TE60020	4698.132	100	3134.017	3053.786	0	80.231	4698.132	100	0	0	20000	19079	-921
83		GSS300114	222.2	100	148.225	144.43	0	3.795	222.2	100	0	0	946	902	-44
84		GSS-NS300115	10.4	100	6.938	6.76	0	0.178	10.4	100	0	0	44	42	-2
85		GSS-TE600008	823.529	100	549.357	535.294	0	14.064	823.529	100	0	0	3506	3344	-161
86		SS-1400225	4814.639	97	2690.92	2544.326	0	23.142	4938.091	100	81.418	123.452	20496	19847	-649
87		SS-1400200	481.149	98	312.051	297.03	0	2.684	493.486	100	9.505	12.337	2048	1972	-76
88		NGLNG006	1130.218	100	403.69	403.69	0	0	1130.218	100	0	0	6346	6147	-200
89		BOS-NLYNN	937.364	100	1025.601	1025.601	0	0	937.364	100	0	0	5263	4496	-768
90		BOS-NSALEM	936.389	100	804.212	804.212	0	0	936.389	100	0	0	5258	4572	-686
91		ESXHAVERHILL	332.8	100	493.734	493.734	0	0	332.8	100	0	0	1869	1792	-77
92		LOWTEWKSBURY	0	0	909.796	44.225	0	0	865.571	100	0	865.571	0	4098	4098
93		LOWWESTFORD	3.382	100	165.625	165.625	0	0	3.382	100	0	0	19	64	45
94		BOS-SCOMMPT	1068.434	100	1265.956	1265.956	0	0	1068.434	100	0	0	5999	5103	-897
95		CAPEWAREHAM	6.656	100	6.656	6.656	0	0	6.656	100	0	0	37	37	0
96		CAPEYARMOUTH	143.832	100	133.82	133.82	0	0	143.832	100	0	0	808	805	-3
97															
98		Total	24933.901	95	16098.215	14731.49	0	175.275	26125.34	100	93.241	1191.443	111938	110108	-1829
99		Transportation Summary													
100															
101			Total	Fuel						Cap Rel		Average			
102		Segment	Flow	Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Revenue	Net Cost	Net Cost			
103		TGP256	557.241	5.071	552.17	3844.545	3292.375	50	940	0	990	1.7769			
104		TGP90618	144.886	1.343	143.543	356.24	212.697	13	87	0	100	0.6907			
105		TGP90622	93.219	0.864	92.355	235.425	143.07	8	58	0	66	0.707			
106		UNIM12197	881.587	8.821	872.765	3211.27	2338.505	0	260	0	260	0.2947			
107		UNIM12198	587.9	5.922	581.978	2240.005	1658.027	0	181	0	181	0.3083			
108		UNIM12199	192.85	1.94	190.91	746.425	555.515	0	60	0	60	0.3131			
109		TCP29601	874.607	11.448	863.159	3175.865	2312.706	18	1176	0	1195	1.3659			
110		TCP29602	578.396	7.666	570.73	2215.55	1644.82	12	821	0	833	1.4397			
111		TCP29603	192.65	2.538	190.112	738.395	548.283	4	274	0	278	1.4406			
112		IGT42001	4146.51	4.587	4141.923	16838.545	12696.622	20	3652	0	3672	0.8856			
113		IGT48001	184.39	0.286	184.103	2215.55	2031.447	1	481	0	481	2.6109			
114		TGP95343	993.931	9.515	984.416	3139	2154.584	89	768	0	856	0.8616			
115		TGP95344BOS	1271.231	12.25	1258.981	5475	4216.019	113	1339	0	1452	1.1425			
116		TGP95344MEN	1638.897	16.455	1622.442	7300	5677.558	146	1786	0	1931	1.1784			
117		TGP95347	292.535	2.718	289.818	730	440.182	26	179	0	205	0.6996			
118		TGP95348MEN	129.432	1.269	128.164	2190	2061.836	12	536	0	547	4.2275			
119		AGT9221	4513.202	45.913	4467.29	7289.05	2821.76	8	1465	0	1473	0.3264			
120		AGT9227	1474.446	14.446	1460	1460	0	3	293	0	296	0.2008			

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
121		AGT93203CMEN	737.223	7.223	730	730	0	9	154	0	164	0.2219			
122		TGP64023BG	7406.926	288.731	7118.195	11434.355	4316.16	13	13837	0	13850	1.8698			
123		TGP64023MEN	4292.311	167.013	4125.298	7076.62	2951.322	7	0	0	7	0.0017			
124		TGP64023Stor	2294.023	74.73	2219.292	18510.975	16291.683	4	0	0	4	0.0017			
125		TGP64023HON	192.281	7.046	185.234	18510.975	18325.741	0	0	0	0	0.0017			
126		TGP64024BG	9924.097	386.355	9537.742	15638.425	6100.683	17	16912	0	16929	1.7059			
127		TGP64024MEN	4246.991	165.12	4081.871	6986.1	2904.229	7	0	0	7	0.0017			
128		TGP64024Stor	1388.859	45.244	1343.615	22624.525	21280.91	2	0	0	2	0.0017			
129		TGP64024HON	311.902	11.453	300.448	22624.525	22324.077	1	0	0	1	0.0017			
130		AGT510364	3232.904	32.495	3200.409	13870	10669.591	42	2997	0	3039	0.94			
131		AGT510365	3200.409	25.344	3175.066	13870	10694.934	6	485	0	491	0.1535			
132		AGT510366	3175.066	25.081	3149.985	13870	10720.015	6	3815	0	3820	1.2032			
133		TGP2025LH	5086.651	190.792	4895.859	13184.165	8288.306	1621	8995	0	10615	2.0869			
134		TGP2062LH	8106.648	298.422	7808.226	29260.59	21452.364	2553	19753	0	22306	2.7515			
135		TGP2062Z4BG	5116.484	63.739	5052.745	5163.655	110.91	604	3486	0	4089	0.7993			
136		TGP90623LH	2293.549	84.999	2208.549	4879.685	2671.136	722	3287	0	4008	1.7477			
137		TGP90623Z4EG	826.715	10.305	816.41	861.035	44.625	98	580	0	677	0.8195			
138		NFLN01733IN	180.045	0.972	179.073	975.626	796.553	3	0	0	3	0.0152			
139		NFLN01733OUT	174.624	1.327	173.296	936.653	763.357	3	281	0	284	1.6267			
140		TGP623	15013.015	186.675	14826.339	15215.755	389.416	1771	4247	0	6018	0.4009			
141		TGP2029	2284.132	28.565	2255.567	2738.96	483.393	269	764	0	1034	0.4526			
142		TGP2025Z4FSM	1878.4	2.15	1876.25	2326.875	450.625	18	1587	0	1606	0.8548			
143		TGP10778	3705.473	45.641	3659.832	5870.295	2210.463	438	1638	0	2076	0.5602			
144		TGP20241Z4	2098.519	25.915	2072.605	2510.105	437.5	248	690	0	938	0.447			
145		TGP20241Z5	485.683	4.42	481.263	2244.75	1763.487	43	559	0	603	1.2409			
146		TGP90617EG	1646.445	20.383	1626.062	1887.78	261.718	194	527	0	721	0.4381			
147		TGP90620EG	961.893	11.783	950.11	1485.185	535.075	114	415	0	528	0.5491			
148		TET800285	13280.178	820.215	12459.963	32031.305	19571.342	859	15263	0	16122	1.214			
149		TET800286	5152.042	316.085	4835.958	11904.84	7068.882	329	5881	0	6209	1.2052			
150		TET800313	1514.467	93.331	1421.136	3602.185	2181.049	97	1726	0	1823	1.204			
151		TET800469	1618.573	99.656	1518.918	3916.815	2397.897	104	1935	0	2039	1.2595			
152		TET DTI Stor	4047.279	208.742	3838.536	51455.145	47616.609	212	0	0	212	0.0525			
153		TET SS-1 Sto	3163.706	160.735	3002.971	20320.645	17317.674	157	0	0	157	0.0495			
154		AGT92100	7.148	0.076	7.072	37.96	30.888	0	8	0	8	1.134			
155		AGT93002CR	4903.077	52.387	4850.69	13513.671	8662.981	63	3444	0	3507	0.7153			
156		AGT93002EA	12570.445	133.826	12436.619	30242.316	17805.697	162	7366	0	7528	0.5988			
157		AGT93003ECR	1222.583	13.175	1209.408	5055.225	3845.817	16	1269	0	1284	1.0505			
158		AGT93203CLAM	1030.344	11.076	1019.268	3602.185	2582.917	13	760	0	774	0.7509			
159		AGT933003	372.405	3.908	368.497	811.03	442.533	1	261	0	262	0.7024			
160		AGT934001	4024.743	41.546	3983.198	7581.415	3598.217	7	2950	0	2958	0.7348			
161		AGT98002C	640.907	6.947	633.96	2378.365	1744.405	8	565	0	573	0.8938			
162		TXG29962	6.661	0.206	6.455	4847.2	4840.745	0	1523	0	1523	228.6741			
163		DTI100015	1758.889	50.128	1708.761	4736.97	3028.209	40	655	0	695	0.395			
164		TET800287	1855.835	46.019	1809.816	7808.81	5998.994	39	1440	0	1480	0.7972			
165		AGT99058LAM	4645.988	49.108	4596.88	14443.415	9846.535	60	3049	0	3109	0.6692			
166		TRA6425	172.263	1.12	171.143	2312.275	2141.132	26	314	0	340	1.974			
167		TRA6428	10.636	0.069	10.567	210.24	199.673	2	29	0	30	2.8357			
168		AGT93203CCEN	5.173	0.057	5.116	210.605	205.489	0	44	0	45	8.6079			
169		AGT99058CEN	176.538	1.942	174.596	2312.275	2137.679	2	488	0	490	2.778			
170		TGP31898BG	0	0	0	2555	2555	0	179	0	179	0			
171		TGP31898EG	635.868	2.416	633.452	5913	5279.548	23	414	0	437	0.6878			
172		TGP31898CG	1104.932	4.199	1100.733	7300	6199.267	40	511	0	552	0.4992			
173		AGT510025	0	0	0	0	0	0	0	0	0	0			
174		AGT510100	0	0	0	0	0	0	0	0	0	0			
175		DTI700049	144.43	4.116	140.314	335.522	195.208	3	47	0	50	0.3461			
176		TET331009	3053.786	96.4	2957.386	10918.975	7961.589	97	2361	0	2458	0.8048			
177		TET331700	404.19	15.126	389.064	1100.84	711.776	17	238	0	255	0.6302			
178		TET331800	131.103	4.905	126.198	359.525	233.327	5	81	0	87	0.6603			
179		TET800400	0	0	0	848.99	848.99	0	245	0	245	0			
180		AGT9B100	2793.3	29.693	2763.606	6350.647	3587.041	36	2305	0	2341	0.8379			

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
181		AGT9B101C	309.458	3.368	306.09	849.607	543.517	4	308	0	312	1.0091			
182		AGT99012	403.69	4.143	399.547	5429.878	5030.331	5	917	0	922	2.2832			
183		IP N to S	12828.981	0	12828.981	21900	9071.019	0	0	0	0	0			
184		TGPCG>BOS	0	0	0	364635	364635	0	0	0	0	0			
185		TGPCG>COL	0	0	0	364635	364635	0	0	0	0	0			
186		TGPCG>ESX	0	0	0	364635	364635	0	0	0	0	0			
187		BG LNG North	1457.924	0	1457.924	364635	363177.076	0	0	0	0	0			
188		BG LNG South	1637.844	0	1637.844	364635	362997.156	0	0	0	0	0			
189		AIM Hub BG	2303.685	23.337	2280.348	7300	5019.652	4	12264	0	12268	5.3254			
190		AIM Hub CG	2818.875	28.798	2790.077	9125	6334.923	5	15330	0	15335	5.4401			
191		AIM	7135.261	72.423	7062.839	20075	13012.161	13	33726	0	33739	4.7284			
192															
193		Total		4764.252				11784	217260		229045	1.0993			

SENDOUT Model Run
Design Year 2012 / 2013
Differences (AIM Scenario less HubLine Scenario)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	1074: 2013Q3 MA DY AIM IR 8-29-13	Ventyx	Page 1 ƒ┐┐												
2	- Draw 0	SENDOUT® Version 14.1.0 REP 1	26-Nov-2013 ƒ┐┐												
3		Report 1	17:50:38 ƒ┐┐												
4															
5	NOV 2012 thru OCT 2013	USD (000)													
6															
7		Supply Costs		Storage Costs		Transportation Costs		Peak Subperiod							
8		--------------------		--------------------		--------------------		----------------							
9		Commodity Cost	-18749	Injection Cost	-586	Transportation Cost	-441	JAN 14	0						
10		Penalty Cost	2108	Withdrawal Cost	3	Other Variable Cost	0	System Served	0						
11		Other Variable Cost	0	Carrying Cost	0			System Unserved	0						
12				Other Variable Cost	0			Total	0						
13		Total Variable	-16641	Total Variable	-584	Total Variable	-441								
14															
15		Demand/Reservation Co	0	Demand Cost	0	Demand Cost	56632								
16		Other Fixed Cost	0	Other Fixed Cost	0	Other Fixed Cost	0								
17		Total Fixed	0	Total Fixed	0	Total Fixed	56632								
18															
19		Sup Release Revenue	0	Sto Release Revenue	0	Cap Release Revenue	0								
20		Net Supply Cost	-16641	Net Storage Cost	-584	Net Trans Cost	56192	Total Gas Cost	38967						
21								Total Revenue	0						
22								Net Cost	38967						
23															
24		Avg Cost of Served Demand	0.302	USD/DT	Avg Cost of Gas Purc	-0.134	USD/DT								
25		(System Cost/Served Dem.)			(Supply Cost/LDC Pur										
26															
27		Demand Summary													
28			Demand	DSM	Net	Imbal.	Demand			Revenue	Peak	Peak			
29		Class	Before DSM	Impact	Demand	Served	After Unb.	Served	Unserved		Served	Unserved			
30															
31		BOS-N	0	0	0	0	0	0	0	0	0	0			
32		BOS-S	0	0	0	0	0	0	0	0	0	0			
33		ESX	0	0	0	0	0	0	0	0	0	0			
34		LOW	0	0	0	0	0	0	0	0	0	0			
35		CAP	0	0	0	0	0	0	0	0	0	0			
36															
37		Total	0	0	0	0	0	0	0	0	0	0			
38		Supply Summary													
39															
40			Total	Max		Take Under	Take Under	Av Comm	Total	Total	Net	Average			
41		Source	Take	Take	Surplus	Daily Min	Other Min	Cost	Var Cost	Fix Cost	Cost	Net Cost			
42		Niagara	-223.9	0.0	223.9			-0.0459	-919	0	-919	-0.0459			
43		Dawn	-102.7	0.0	102.7			-0.0095	-407	0	-407	-0.0095			
44		Waddington	-1,090.1	0.0	1,090.1			-3.4126	-16,749	0	-16,749	-3.4126			
45		Dracut	-485.8	0.0	485.8			0.0076	-3,048	0	-3,048	0.0076			
46		Wharton	-182.6	0.0	182.6			0.0554	-750	0	-750	0.0554			
47		TETCO Gulf	-541.8	0.0	541.8			-0.0015	-1,898	0	-1,898	-0.0015			
48		TGPZ4	0.0	0.0	0.0			0	0	0	0	0			
49		TGPZ4 Cold	-31.8	0.0	31.8			-0.0532	-137	0	-137	-0.0532			
50		TGP2025Gulf	0.0	0.0	0.0			0	0	0	0	0			
51		TGP2062Gulf	-380.1	0.0	380.1			-0.0022	-1,304	0	-1,304	-0.0022			
52		TGP64023Gulf	414.6	0.0	-414.6			-0.0058	1,373	0	1,373	-0.0058			
53		TGP64024Gulf	-496.3	0.0	496.3			0.0045	-1,670	0	-1,670	0.0045			
54		TGP90623Gulf	-2.1	0.0	2.1			1E-04	-7	0	-7	1E-04			
55		TXG29962Gulf	0.0	0.0	0.0			0	0	0	0	0			
56		M3	-7,290.2	0.0	7,290.2			0.0056	-28,981	0	-28,981	0.0056			
57		M3 Cold	0.0	0.0	0.0			0	0	0	0	0			
58		Distrigas	-537.6	0.0	537.6			-0.0217	-561	0	-561	0.8029			
59		Beverly	-796.7	0.0	796.7			-10.3987	-8,285	0	-8,285	-10.3987			
60		FVS217	-61.8	0.0	61.8			-16.093	-995	0	-995	-21.3562			

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
61		Southbridge	-11.7	0.0	11.7			-14.6713	-171	0	-171	-14.6713			
62		Norwood	-14.2	0.0	14.2			-14.6713	-209	0	-209	-14.6713			
63		DTI Lebanon	0.0	0.0	0.0			0	0	0	0	0			
64		OPR BOS	0.0	0.0	0.0			-25.808	-1	0	-1	-25.808			
65		OPR ESX	0.0	0.0	0.0			0	0	0	0	0			
66		OPR LOW	-32.6	0.0	32.6			0.0719	-842	0	-842	0.0719			
67		OPR CAP	0.0	0.0	0.0			0	0	0	0	0			
68		DracutHess	0.0	0.0	0.0			0	0	0	0	0			
69		BevRepsol	0.0	0.0	0.0			0	0	0	0	0			
70		BevHess	0.0	0.0	0.0			0	0	0	0	0			
71		AIM	12,257.8	37,230.0	24,972.2			3.9908	48,919	0	48,919	3.9908			
72															
73		Total	390.1						-16,641	0	-16,641				
74		Storage Summary													
75															
76			Starting	%	Total	Total	NetInv	Inj	Final	%	With.	Diff in	Start	Final	Diff in
77		Storage	Balance	Full	Inj.	With.	Adj.	Fuel	Balance	Full	Fuel	Balance	Value	Value	Value
78		Honeoye	0.0	0.0	-37.8	-37.8	0.0	0.0	0.0	0.0	0.0	0.0	0	17	16
79		NFLO01734	0.0	0.0	-28.1	-27.8	0.0	-0.3	0.0	0.0	-0.4	0.0	0	13	13
80		FSMA524	0.0	0.0	-5.0	-5.0	0.0	-0.1	0.0	0.0	0.0	0.0	0	3	3
81		FSMA527	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
82		GSS-TE60020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
83		GSS300114	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
84		GSS-NS300115	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
85		GSS-TE600008	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
86		SS-1400225	0.0	0.0	18.6	18.4	0.0	0.2	0.0	0.0	0.6	0.0	0	-5	-5
87		SS-1400200	0.0	0.0	57.7	57.2	0.0	0.5	0.0	0.0	1.8	0.0	0	-15	-15
88		NGLNG006	0.0	0.0	-729.0	-812.1	0.0	0.0	83.1	7.0	0.0	83.1	0	512	511
89		BOS-NLYNN	0.0	0.0	-99.3	-99.3	0.0	0.0	0.0	0.0	0.0	0.0	0	-35	-35
90		BOS-NSALEM	0.0	0.0	-264.9	-264.9	0.0	0.0	0.0	0.0	0.0	0.0	0	12	12
91		ESXHAVERHILL	0.0	0.0	179.2	96.0	0.0	0.0	83.2	25.0	0.0	83.2	0	430	430
92		LOWTEWKSBURY	0.0	0.0	283.6	0.0	0.0	0.0	283.6	33.0	0.0	283.6	0	1280	1280
93		LOWWESTFORD	0.0	0.0	99.6	99.6	0.0	0.0	0.0	0.0	0.0	0.0	0	-19	-19
94		BOS-SCOMMPT	0.0	0.0	-83.7	-83.7	0.0	0.0	0.0	0.0	0.0	0.0	0	-33	-34
95		CAPEWAREHAM	0.0	0.0	6.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0	-1	-1
96		CAPEYARMOUTH	0.0	0.0	71.0	71.0	0.0	0.0	0.0	0.0	0.0	0.0	0	-16	-16
97															
98		Total	0.0	0.0	-532.2	-982.3	0.0	0.2	449.9	2.0	2.1	449.9	0	2141	2142
99		Transportation Summary													
100															
101			Total	Fuel						Cap Rel		Average			
102		Segment	Flow	Consumed	Delivered	Max Flow	Surplus	Var Cost	Fix Cost	Revenue	Net Cost	Net Cost			
103		TGP256	-223.9	-2.0	-221.9	0.0	221.9	-20.0	0.0	0.0	-20.0	0.4838			
104		TGP90618	0.1	0.0	0.1	0.0	-0.1	0.0	0.0	0.0	0.0	-0.0002			
105		TGP90622	-0.1	0.0	-0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0004			
106		UNIM12197	-51.0	-0.5	-50.6	0.0	50.6	0.0	0.0	0.0	0.0	0.0161			
107		UNIM12198	-40.1	-0.4	-39.8	0.0	39.8	0.0	0.0	0.0	0.0	0.0197			
108		UNIM12199	-11.5	-0.1	-11.4	0.0	11.4	0.0	0.0	0.0	0.0	0.0176			
109		TCP29601	-58.2	-0.6	-57.6	0.0	57.6	-1.0	0.0	0.0	-1.0	0.0839			
110		TCP29602	-32.5	-0.3	-32.2	0.0	32.2	-1.0	0.0	0.0	0.0	0.0756			
111		TCP29603	-11.1	-0.1	-11.0	0.0	11.0	0.0	0.0	0.0	0.0	0.0772			
112		IGT42001	-1,130.7	-2.1	-1,128.6	0.0	1,128.6	-5.0	0.0	0.0	-5.0	0.1888			
113		IGT48001	-60.2	0.0	-60.2	0.0	60.2	0.0	0.0	0.0	-1.0	0.6411			
114		TGP95343	-270.9	-2.5	-268.4	0.0	268.4	-24.0	0.0	0.0	-25.0	0.1654			
115		TGP95344BOS	-297.3	-2.7	-294.7	0.0	294.7	-27.0	0.0	0.0	-27.0	0.1996			
116		TGP95344MEN	-559.9	-5.0	-554.9	0.0	554.9	-50.0	0.0	0.0	-50.0	0.2773			
117		TGP95347	2.0	0.0	2.0	0.0	-2.0	0.0	0.0	0.0	1.0	-0.0043			
118		TGP95348MEN	-62.6	-0.6	-62.1	0.0	62.1	-5.0	0.0	0.0	-6.0	1.3496			
119		AGT9221	17.8	0.2	17.6	0.0	-17.6	0.0	0.0	0.0	0.0	-0.0013			
120		AGT9227	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0			

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
121		AGT93203CMEN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0			
122		TGP64023BG	48.0	2.0	46.0	0.0	-46.0	0.0	0.0	0.0	0.0	-0.0122			
123		TGP64023MEN	-4.6	0.1	-4.6	0.0	4.6	0.0	0.0	0.0	0.0	0			
124		TGP64023Stor	425.6	13.9	411.8	0.0	-411.8	1.0	0.0	0.0	1.0	0			
125		TGP64023HON	-54.5	-1.9	-52.6	0.0	52.6	0.0	0.0	0.0	0.0	0			
126		TGP64024BG	-0.7	0.0	-0.7	0.0	0.7	0.0	0.0	0.0	0.0	0.0002			
127		TGP64024MEN	-51.0	-2.4	-48.6	0.0	48.6	0.0	0.0	0.0	0.0	0			
128		TGP64024Stor	-460.0	-15.0	-445.0	0.0	445.0	-1.0	0.0	0.0	-1.0	0			
129		TGP64024HON	15.5	0.6	14.8	0.0	-14.8	0.0	0.0	0.0	0.0	0			
130		AGT510364	-688.0	-7.5	-680.5	0.0	680.5	-8.0	0.0	0.0	-9.0	0.1626			
131		AGT510365	-680.5	-7.4	-673.0	0.0	673.0	-1.0	0.0	0.0	-1.0	0.0266			
132		AGT510366	-673.0	-7.3	-665.7	0.0	665.7	-1.0	0.0	0.0	-1.0	0.2101			
133		TGP2025LH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0			
134		TGP2062LH	-380.1	-14.0	-366.1	0.0	366.1	-120.0	0.0	0.0	-119.0	0.1091			
135		TGP2062Z4BG	-58.2	-0.7	-57.5	0.0	57.5	-7.0	0.0	0.0	-7.0	0.0077			
136		TGP90623LH	-2.1	-0.1	-2.0	0.0	2.0	0.0	0.0	0.0	-1.0	0.0013			
137		TGP90623Z4EG	-13.7	-0.2	-13.6	0.0	13.6	-1.0	0.0	0.0	-2.0	0.0114			
138		NFLN01733IN	-28.2	-0.2	-28.1	0.0	28.1	0.0	0.0	0.0	0.0	0			
139		NFLN01733OUT	-27.4	-0.2	-27.2	0.0	27.2	0.0	0.0	0.0	0.0	0.2185			
140		TGP623	10.3	0.2	10.1	0.0	-10.1	1.0	0.0	0.0	1.0	-0.0002			
141		TGP2029	1.6	0.0	1.6	0.0	-1.6	0.0	0.0	0.0	0.0	-0.0003			
142		TGP2025Z4FSM	-0.2	0.0	-0.2	0.0	0.2	0.0	0.0	0.0	0.0	0			
143		TGP10778	-1.4	0.0	-1.4	0.0	1.4	0.0	0.0	0.0	0.0	1E-04			
144		TGP20241Z4	-16.0	-0.2	-15.8	0.0	15.8	-2.0	0.0	0.0	-2.0	0.0025			
145		TGP20241Z5	-37.8	-0.3	-37.4	0.0	37.4	-4.0	0.0	0.0	-3.0	0.0831			
146		TGP90617EG	12.5	0.1	12.4	0.0	-12.4	1.0	0.0	0.0	1.0	-0.0024			
147		TGP90620EG	1.2	0.0	1.2	0.0	-1.2	1.0	0.0	0.0	0.0	-0.0005			
148		TET800285	-221.7	-12.1	-209.6	0.0	209.6	-12.0	0.0	0.0	-12.0	0.0191			
149		TET800286	-197.3	-11.1	-186.2	0.0	186.2	-11.0	0.0	0.0	-11.0	0.0424			
150		TET800313	-114.9	-6.4	-108.6	0.0	108.6	-7.0	0.0	0.0	-7.0	0.081			
151		TET800469	-88.2	-4.9	-83.3	0.0	83.3	-5.0	0.0	0.0	-4.0	0.0623			
152		TET DTI Stor	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0			
153		TET SS-1 Sto	80.4	4.1	76.3	0.0	-76.3	5.0	0.0	0.0	5.0	0.0001			
154		AGT92100	-11.4	-0.1	-11.3	0.0	11.3	0.0	0.0	0.0	0.0	0.6897			
155		AGT93002CR	-2,880.9	-28.3	-2,852.6	0.0	2,852.6	-37.0	0.0	0.0	-37.0	0.2599			
156		AGT93002EA	-2,126.7	-20.5	-2,106.2	0.0	2,106.2	-27.0	0.0	0.0	-27.0	0.0847			
157		AGT93003ECR	-1,544.7	-15.6	-1,529.2	0.0	1,529.2	-20.0	0.0	0.0	-20.0	0.5792			
158		AGT93203CLAM	-273.6	-2.7	-270.9	0.0	270.9	-4.0	0.0	0.0	-3.0	0.1549			
159		AGT933003	-117.0	-1.1	-115.9	0.0	115.9	0.0	0.0	0.0	0.0	0.1674			
160		AGT934001	-270.2	-2.5	-267.7	0.0	267.7	-1.0	0.0	0.0	0.0	0.0461			
161		AGT98002C	-126.7	-1.3	-125.4	0.0	125.4	-2.0	0.0	0.0	-1.0	0.1454			
162		TXG29962	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0			
163		DTI100015	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0			
164		TET800287	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0			
165		AGT99058LAM	-217.8	-2.0	-215.8	0.0	215.8	-3.0	0.0	0.0	-3.0	0.0294			
166		TRA6425	-164.1	-1.1	-163.0	0.0	163.0	-25.0	0.0	0.0	-25.0	0.8885			
167		TRA6428	-18.5	-0.1	-18.4	0.0	18.4	-2.0	0.0	0.0	-3.0	1.7049			
168		AGT93203CCEN	-21.0	-0.2	-20.8	0.0	20.8	0.0	0.0	0.0	0.0	6.895			
169		AGT99058CEN	-160.5	-1.7	-158.8	0.0	158.8	-2.0	0.0	0.0	-2.0	1.3167			
170		TGP31898BG	-322.2	-1.2	-321.0	0.0	321.0	-12.0	0.0	0.0	-12.0	-0.5919			
171		TGP31898EG	-96.4	-0.4	-96.0	0.0	96.0	-4.0	0.0	0.0	-4.0	0.0857			
172		TGP31898CG	-67.2	-0.3	-67.0	0.0	67.0	-3.0	0.0	0.0	-2.0	0.0265			
173		AGT510025	-77.6	-0.9	-76.8	-9,125.0	-9,048.2	0.0	-3,010.0	0.0	-3,010.0	-38.7686			
174		AGT510100	-719.1	-7.9	-711.2	-7,300.0	-6,588.8	-1.0	-1,678.0	0.0	-1,679.0	-2.3354			
175		DTI700049	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0			
176		TET331009	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0			
177		TET331700	0.9	0.0	0.9	0.0	-0.9	0.0	0.0	0.0	0.0	-0.0014			
178		TET331800	-0.9	0.0	-0.9	0.0	0.9	0.0	0.0	0.0	0.0	0.0043			
179		TET800400	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0			
180		AGT9B100	-184.1	-1.8	-182.3	0.0	182.3	-2.0	0.0	0.0	-2.0	0.051			

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
181		AGT9B101C	-51.6	-0.5	-51.1	0.0	51.1	-1.0	0.0	0.0	-1.0	0.1423			
182		AGT99012	-812.1	-8.9	-803.1	0.0	803.1	-11.0	0.0	0.0	-10.0	1.5165			
183		IP N to S	-1,444.1	0.0	-1,444.1	0.0	1,444.1	0.0	0.0	0.0	0.0	0			
184		TGPCG>BOS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0			
185		TGPCG>COL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0			
186		TGPCG>ESX	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0			
187		BG LNG North	94.9	0.0	94.9	0.0	-94.9	0.0	0.0	0.0	0.0	0			
188		BG LNG South	-542.8	0.0	-542.8	0.0	542.8	0.0	0.0	0.0	0.0	0			
189		AIM Hub BG	2,303.7	23.3	2,280.3	7,300.0	5,019.7	4.0	12,264.0	0.0	12,268.0	5.3254			
190		AIM Hub CG	2,818.9	28.8	2,790.1	9,125.0	6,334.9	5.0	15,330.0	0.0	15,335.0	5.4401			
191		AIM	7,135.3	72.4	7,062.8	20,075.0	13,012.2	13.0	33,726.0	0.0	33,739.0	4.7284			
192															
193		Total		-62.1				-441.0	56,632.0		56,192.0	0.2925			

FORM A

Proceeding:...EB-2015-0029 EB-2015-0049.......

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ..Paul Chernick..................(*name*). I live at ..Lexington............... (*city*), in the *state* of Massachusetts.

2. I have been engaged by or on behalf of ...Green Energy Coalition... (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ....July 28, 2015....................................

Signature