Thomas G. Robinson
Deputy General Counsel

October 27, 2005

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 3701 – Demand Side Management Programs
Responses to Commission's 1st Set of Data Requests

Dear Ms. Massaro:

Enclosed please find ten (10) copies of The Narragansett Electric Company's ("Company") d/b/a National Grid responses to the Commission's first set of data requests in the above-captioned proceeding.

Data Request 1-3 contains confidential information and has been redacted. Pursuant to Section 1.2(g) of the Commission's Rules of Practice and Procedure, the Company hereby requests a preliminary finding that the response to Data Request 1-3 be exempt from the mandatory public disclosure requirements of the Access to Public Records Act on the grounds that it contains confidential business information. R.I.G.L. 38-2-2(B). In accordance with Rule 1.2(g) of the Commission's Rules of Practice and Procedure, I am providing a complete unredacted copy of Data Request 1-3 under separate cover in a sealed envelope marked **"Contains Privileged and Confidential Materials – Do Not Release."**

The Company's response to Data Request 1-3 provides the Commission with the identity of customers who participated in the Company's energy-efficiency programs, the measures they installed, and the amount of rebates that they received. Customers consider this information confidential and proprietary to their business, and therefore, the Company holds this information confidential.

Thank you for your attention to this transmittal. Should you have any questions regarding this filing, please do not hesitate to contact me at (508) 389-2877.

Very truly yours,

Thomas G. Robinson

Enclosures

cc: Docket 3701 Service List

25 Research Drive, Westborough, MA 01582
T: 508-389-2877 ■ F: 508-389-2463 ■ thomas.robinson@us.ngrid.com ■ www.nationalgrid.com

Certificate of Service

I hereby certify that a copy of the cover letter and accompanying material(s) have been hand-delivered or sent via U.S. mail to the parties listed below.

Joanne M. Scanlon
The Narragansett Electric Company

October 27, 2005
Date

Narragansett Electric Co. – 2006 Demand Side Management – Dkt. 3701
Service list as of 10/28/05

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Original & nine (9) copies file w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd.	Lmassaro@puc.state.ri.us Cwilson@puc.state.ri.us Dhartley@puc.state.ri.us	401-941-4500 401-941-1691

Commission Data Request 1-1

Request:

For each of the Large C&I Programs, please be prepared at the Technical Session to provide an estimate of the number of participants expected in 2006.

Response:

The Company has provided a projection of participants by program in Attachment 10, page 3 of 3 in the Settlement, and is prepared to discuss this Attachment at the Technical Session. Under the Large C&I programs, the Company estimates that Design 2000*plus* will have 189 participants and Energy Initiative will have 185 participants with a total expectation of 374 participants.

Prepared by or under the supervision of: Michael McAteer

Commission Data Request 1-2

Request:

Please identify the schools which participated in either Design2000*plus* or the Schools Initiative in 2004 and 2005 to date. Please briefly summarize the measures installed and please also provide the number of dollars spent on each school.

Response:

The following table lists the schools that participated in either Design 2000*plus* or the Schools Initiative in 2004 and 2005 to date. The table also indicates measure type and rebate amount.

School		Program Name	Measure Category	Authorized Rebate
CITY OF CRANSTON	North Scituate Avenue Elementary	Schools Initiative	Custom Lighting and Contols	$37,575.00
LINCOLN SCHOOL	Private School	Design 2000	Lighting	$6,895.00
MIDDLETOWN SCHOOL DEPARTMENT	Joseph H. Gaudet Middle School	Design 2000	Custom	$20,252.00
MOSES BROWN SCHOOL	Private School	Design 2000	Lighting	$10,110.00
PENNFIELD SCHOOL	Private School	Schools Initiative	Custom Lighting	$42,134.00
PROVIDENCE SCHOOL DEPT	West Broadway Elementary	Design 2000	Dry Type Transformers	$23,800.00
ST ANDREWS SCHOOL	Private School	Design 2000	Cool Choice	$9,271.00
ST GEORGES SCHOOL	Private School	Design 2000	Lighting	$450.00
TOWN OF COVENTRY-SCHOOLS	Coventry Middle School	Design 2000	Lighting	$10,665.00
WARWICK PUBLIC SCHOOLS	Aldrich Jr HS (New Addition)	Design 2000	Lighting	$1,480.00
WARWICK PUBLIC SCHOOLS	Cedar Hill Elementary	Design 2000	Lighting	$1,020.00
WARWICK PUBLIC SCHOOLS	Gorton Elementary	Design 2000	Lighting	$1,770.00
WARWICK PUBLIC SCHOOLS	Greenwood Elementary	Design 2000	Lighting	$2,165.00
WARWICK PUBLIC SCHOOLS	Park Elementary School	Design 2000	Lighting	$2,650.00
WARWICK PUBLIC SCHOOLS	Randall Holden Elementary	Design 2000	Lighting	$2,730.00
			Total	**$172,967.00**

Prepared by or under the supervision of: Michael McAteer

Commission Data Request 1-3

Request:

With regard to the Large C&I Programs in 2004 and 2005 to date, with the exception of the schools listed in response to Commission 1-2, please identify the businesses which participated, identify the programs in which they participated, briefly summarize the measures installed and the number of dollars spent on each participant.

Response:

The response to this request is being provided to the Commission separately with a request for confidential treatment.

Prepared by or under the supervision of: Michael McAteer

Commission Data Request 1-4

Request:

Please provide, for each year since 2000, the number of kWh saved.

Response:
The table below shows the annual kWh, rounded to the nearest 1000, saved by the Company's programs since 2000.

Year	Annual kWh Savings
2000	47,192,000
2001	61,455,000
2002	50,231,000
2003	54,378,000
2004	51,397,000
Five year total	264,652,000

Prepared by or under the supervision of: Jeremy Newberger

Commission Data Request 1-5

Request:

Please be prepared to fully explain Attachment 11 at the Technical Session.

Response:

The Company will be prepared to fully explain Attachment 11 at the Technical Session.

Attachment 11 provides a summary of the avoided costs that are being used to value expected savings from proposed 2006 program efforts. As background on the inputs and assumptions used in the presentation of the avoided costs, Attachment 1-5 is a copy of the presentation material used by ICF Consulting when it presented final results to the study sponsors.

The final Avoided Energy Supply Component Study has not been published yet. The Company will provide a copy of the published report to the Commission once it is available.

Prepared by or under the supervision of: Jeremy Newberger

ICF CONSULTING

Avoided Costs of Energy in New England Due to Energy Efficiency Programs

Presented to

AESC Study Group

September 2005 (revised)

ICF Consulting.[SM] Powered by perspective.[SM]
Industry knowledge. Distinguished professionals. Innovative analytics.

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Outline

- Purpose of the Report
- Background on DSM in New England
  - Key Natural Gas Issues
  - Key Electric Power Issues
- Natural Gas, Oil and Other Fuels Avoided Costs
- Electric Power Avoided Costs

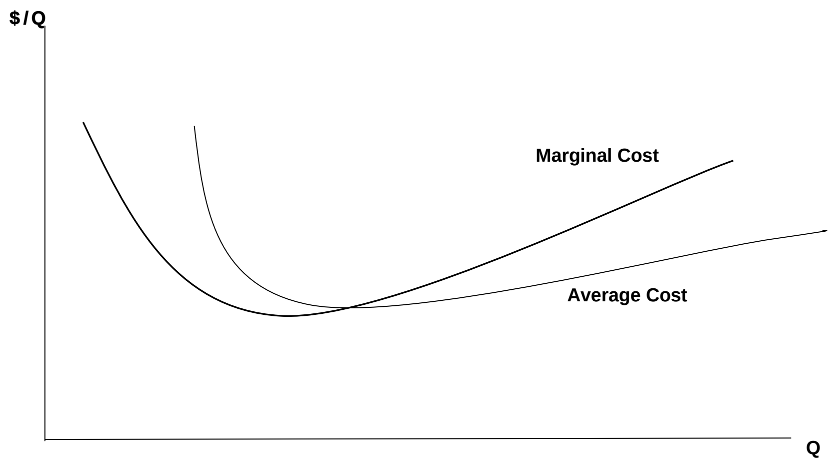
Purpose of the Study

- Develop forecast of the avoided cost of supplying natural gas, other fuels, and electricity
  - Includes forecasts of other key New England fuels: distillate fuel oil, residual fuel oil, kerosene, propane, and wood. Also includes method for transmission and distribution capacity.
  - Output used for regulatory filings and for energy efficiency and demand side management (DSM) program design and assessment.
- Natural gas avoided costs:
  - Costs to LDCs of not having to purchase more gas and capacity to meet peak load
    - Includes both avoided commodity and capacity costs
    - Winter peaks defined as 3, 5, 6 and 7 month winters
- Electric system avoided costs:
  - Costs savings for LSE based on demand reductions
    - Includes Energy and Capacity Payments

Why Value Demand Reductions at Avoided Costs?

- Customer incentives to reduce demand are not aligned with market realities.
  - Regulated customer rates are based on average embedded cost of service (declining block rates)
  - Utilities make investment decisions based on marginal cost, influenced by rate-based regulation
- Integrated resource planning has been implemented in many jurisdictions to help develop a common basis for analyzing supply side and demand side options to meet long term objectives
  - Avoided costs of supply represent the correct comparison for comparing DSM options with supply side options.

Background on DSM



New England Avoided Cost Issues

- Natural Gas Issues
  - New England is at the end of the continental pipeline network for its gas supply.
  - Pipeline capacity expansions or LNG will be needed to meet growing peak demand behind LDC city gates.
  - Gas costs and pipeline, storage, and LNG tariffs determine the avoided costs of natural gas supply.
- Electric Power Issues
  - New England is relatively isolated from other regional power markets.
  - Several internal transmission constraints exist in New England.
  - Structural changes are actively occurring in the market place including a movement towards locational capacity markets.
  - ICF approach shows significant savings can exist from demand side management programs, particularly those affecting peak hour load.

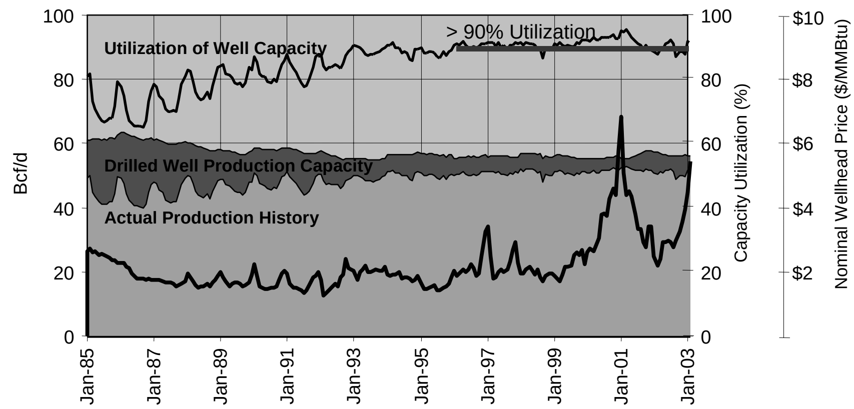
Natural Gas, Oil and Other Fuels Avoided Costs

Tasks 1, 2, and 5

Key Drivers of Gas Prices and Avoided Cost

- Constrained supply deliverability limits short term response to demand and prices
- New supply is from more distant and costly settings
- Growing use of gas in power generation drives demand
- Local infrastructure constraints contributes to wild swings in prices away from Henry Hub
  - Current capacity into New England is about 4.1 Bcf/d
- Gas prices will remain volatile and markets tight

Surplus Production Capacity has Vanished



Source: Energy Information Administration

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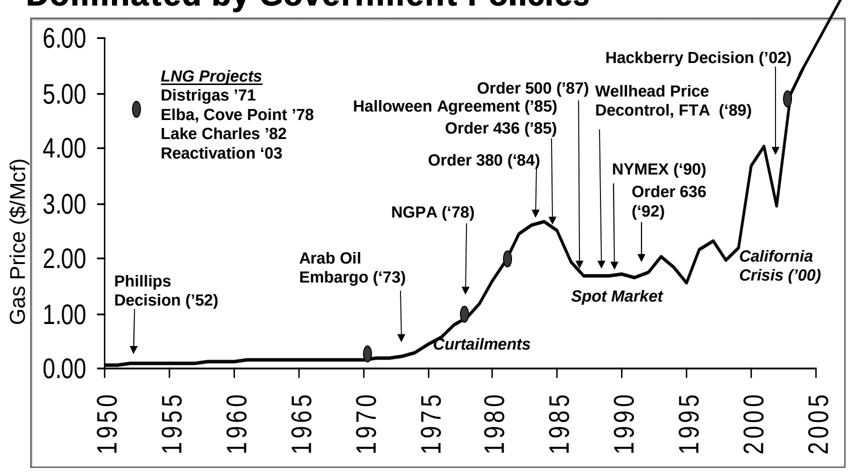
North American Gas Markets have been Dominated by Government Policies



Source: *EIA Historical Natural Gas Annual 1930 Through 2003.*

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North American Gas Flows and New England

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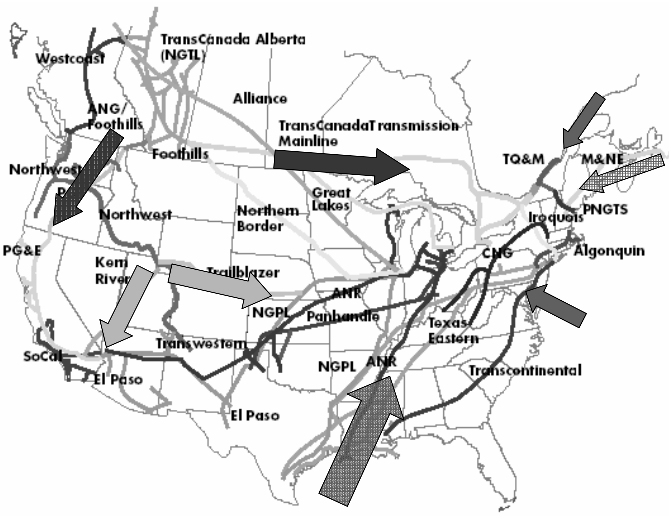
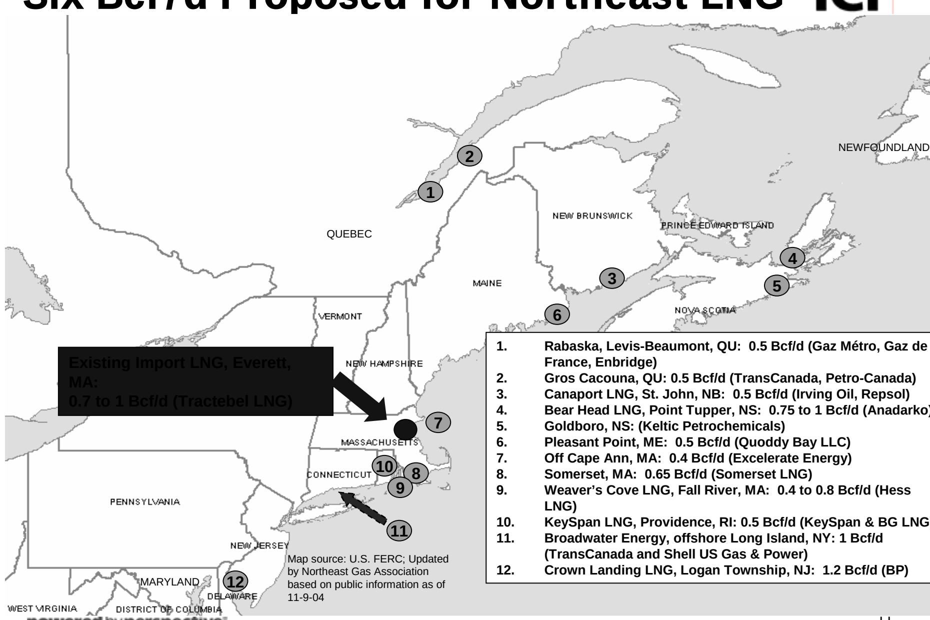


Six Bcf/d Proposed for Northeast LNG

ICF



1. **Rabaska, Levis-Beaumont, QU: 0.5 Bcf/d (Gaz Métro, Gaz de France, Enbridge)**
2. **Gros Cacouna, QU: 0.5 Bcf/d (TransCanada, Petro-Canada)**
3. **Canaport LNG, St. John, NB: 0.5 Bcf/d (Irving Oil, Repsol)**
4. **Bear Head LNG, Point Tupper, NS: 0.75 to 1 Bcf/d (Anadarko)**
5. **Goldboro, NS: (Keltic Petrochemicals)**
6. **Pleasant Point, ME: 0.5 Bcf/d (Quoddy Bay LLC)**
7. **Off Cape Ann, MA: 0.4 Bcf/d (Excelerate Energy)**
8. **Somerset, MA: 0.65 Bcf/d (Somerset LNG)**
9. **Weaver's Cove LNG, Fall River, MA: 0.4 to 0.8 Bcf/d (Hess LNG)**
10. **KeySpan LNG, Providence, RI: 0.5 Bcf/d (KeySpan & BG LNG)**
11. **Broadwater Energy, offshore Long Island, NY: 1 Bcf/d (TransCanada and Shell US Gas & Power)**
12. **Crown Landing LNG, Logan Township, NJ: 1.2 Bcf/d (BP)**

New England Consumption is Seasonal

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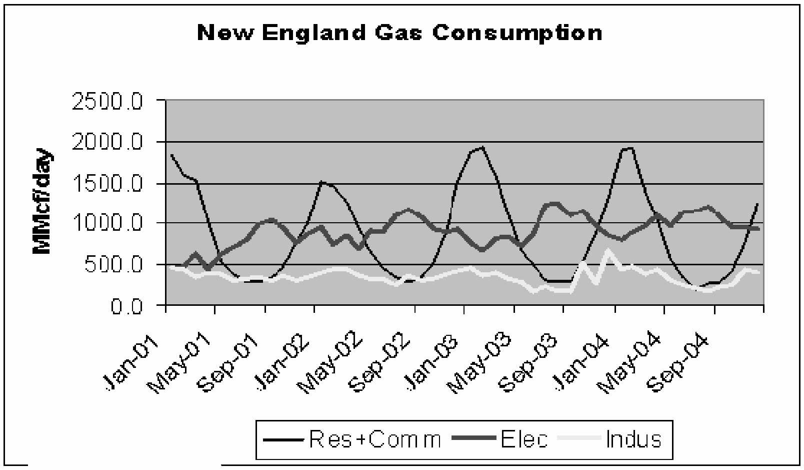

Source: EIA, 2005.

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Basis Volatility at Hubs Feeding New England

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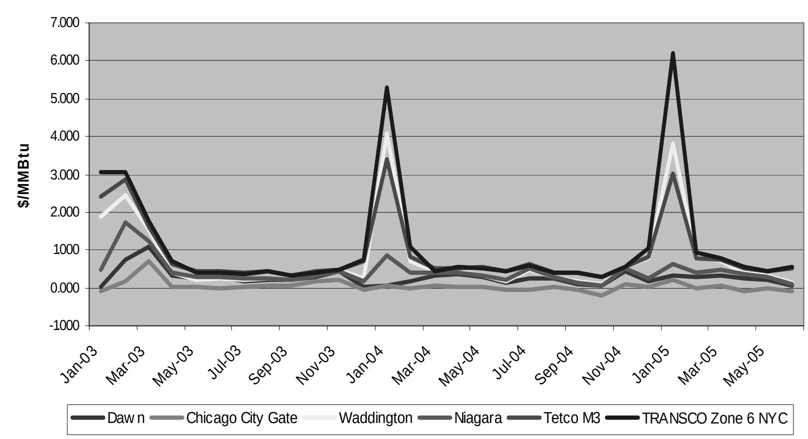

Source: Gas Daily

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Natural Gas Avoided Cost Methodology

- FERC's Order 636 (1992)
  - Unbundled gas sales from transportation services
  - Straight fixed variable rate design allocates all fixed costs to demand charges, giving better pricing signals for capacity purchases
  - Deregulated gas prices signal commodity scarcity and surplus
  - Secondary market in capacity allows capacity holders to resell unused capacity
- Avoided cost is defined as the total change in cost resulting from not having to serve the incremental customer demand
  - Alternatively: What would a LDC have to pay in order serve incremental load?
- LDCs buy capacity to meet peak demand
  - Changing demand in the peak heating season has different cost implications from changing demand in the off peak season

Natural Gas Avoided Cost Methodology

- We have used Long Run Avoided Cost concept
  - Assumes fixed costs can be avoided for decrements of demand
  - Includes incremental fixed cost for avoided expansions
- Our calculations involve developing a forward estimate of the cost of gas plus the cost of acquiring pipeline capacity, storage, and LNG services to serve that incremental use
- Components of cost
  - The cost of the physical gas (Henry Hub Price)
  - Transportation costs Winter Storage costs
  - Winter LNG peaking

Steps in the Methodology

- Step 1: Forecast base Henry Hub price to 2025
- Step 2: Establish seasonal variation for forecast years
- Step 3: Establish base pipeline transportation, storage, LNG costs
- Step 4: Allocate pipeline, storage, LNG use to seasons based on LDC use
- Step 5: Allocate costs to the seasons using the shares
- Step 6: Estimate wholesale avoided cost at the city gate
- Step 7: Estimate retail avoided costs using LDC margins

Cost of Physical Gas

- We constructed a gas forecast using a combination of modeled long term gas prices, futures, EIA short term forecast, and a pessimistic LNG supply assessment.
  - Short term gas prices were taken from the NYMEX futures market curve.
  - Long term gas prices were forecasted using ICF's North American Natural Gas Analysis System (NANGAS®)
  - Adjustment was made from a separate ICF low supply run, based on lower LNG imports.
  - Late in the study we made an adjustment for Hurricane Katrina effects. This resulted in increases to the forecast for the 2005 – 2009 period. Unless noted, values presented herein reflect the post-Katrina adjustments.
- Seasonality was estimated using historical price swings from five years of daily spot price data
  - The average seasonality in prices over the past five years was then used for all of the years in our forecast
  - Seasonality was mapped to the different winter month/summer month definitions

ICF Long Term Forecast

- Gas prices will decline from current levels as supply increases
- Prices stay high enough in Midwest to attract Alaskan Gas in 2011
  - At 4.5 Bcf/d, Alaska will have major impact on prices
- After 2011, prices gradually increase until 2018 when new supplies from enter the market and reduce prices again
  - Gulf off shore
  - Deep onshore gas
  - Rockies
  - Coal bed methane
- At the end of the period, strong gas demand again drives up prices

North American Gas Supply Outlook

- Current estimates of technically recoverable resource in the US is 1,280 Tcf, 535 Tcf in Canada
- Producers have more than replaced production with reserves additions since 2000
- Canadian conventional production in decline, but
  - Coal bed methane resource is huge, but un-tapped so far
- Frontiers gas is substantial
  - Alaska and Mackenzie Delta can contribute up to 6 bcf/d
- More of the resource base is in deep, tight, remote settings
- Technology improvements will lower cost and increase access to these resources

Long Term Forecast Comparison: AESC Studies Compared to Annual Energy Outlook (EIA)

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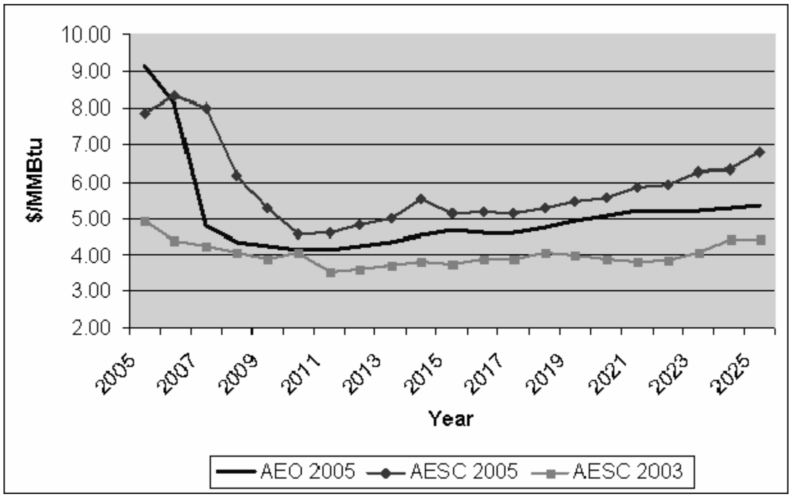

Henry Hub Price Forecast

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		Winter=(Dec-Feb)		Winter=(Nov-Mar)		Winter=(Oct-Mar)		Winter=(Oct-Apr)	
		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
	HH 2005$/	**-3.57%**	**10.71%**	**-4.12%**	**5.76%**	**-4.46%**	**4.46%**	**-5.05%**	**3.61%**
2005	7.88	7.60	8.73	7.56	8.34	7.53	8.24	7.49	8.17
2006	8.33	8.04	9.23	7.99	8.81	7.96	8.71	7.91	8.64
2007	8.02	7.73	8.87	7.69	8.48	7.66	8.37	7.61	8.30
2008	6.16	5.94	6.82	5.91	6.52	5.89	6.44	5.85	6.39
2009	5.25	5.06	5.81	5.03	5.55	5.02	4.89	4.99	5.44
2010	4.55	4.39	5.04	4.37	4.82	4.35	4.76	4.32	4.72
2011	4.61	4.45	5.10	4.42	4.88	4.41	4.82	4.38	4.78
2012	4.80	4.63	5.32	4.61	5.08	4.59	5.02	4.56	4.98
2013	4.98	4.81	5.52	4.78	5.27	4.76	5.21	4.73	5.16
2014	5.51	5.32	6.11	5.29	5.83	5.27	5.76	5.24	5.71
2015	5.14	4.95	5.69	4.92	5.43	4.91	5.37	4.88	5.32
2016	5.16	4.97	5.71	4.95	5.45	4.93	5.39	4.90	5.34
2017	5.13	4.95	5.68	4.92	5.43	4.90	5.36	4.87	5.32
2018	5.27	5.08	5.83	5.05	5.57	5.04	5.51	5.00	5.46
2019	5.44	5.25	6.02	5.22	5.75	5.20	5.68	5.17	5.64
2020	5.56	5.36	6.16	5.33	5.88	5.31	5.81	5.28	5.76
2021	5.84	5.63	6.46	5.60	6.17	5.58	6.10	5.54	6.05
2022	5.92	5.71	6.56	5.68	6.27	5.66	6.19	5.63	6.14
2023	6.26	6.03	6.93	6.00	6.62	5.98	6.53	5.94	6.48
2024	6.34	6.12	7.02	6.08	6.71	6.06	6.63	6.02	6.57
2025	6.79	6.55	7.52	6.51	7.18	6.49	7.09	6.45	7.04

Transportation Costs

- Estimating transportation costs involved using tariffs for Firm Transportation (FT) of the relevant pipelines
  - In Northern and Central New England El Paso's Tennessee Gas Pipeline (TGP) is the dominant pipeline
  - In Southern New England Duke Energy's Texas Eastern Transmission Company (TETCO) and Algonquin Gas Transmission (AGT) constitutes the primary system
- For purposes of identifying the relevant rates, we used the Gulf Coast to New England zoned charges
- Costs include
  - Annualized demand charges (for pipeline capacity) expressed as $/MMBtu of contract demand (monthly demand x12)
  - Unit commodity charges for variable costs of throughput ($/MMBtu)
  - Fuel cost (% of gas throughput)

Storage & LNG

- We assumed the storage contracts for each of the regions are tied to the relevant pipelines – TGP and TETCO/AGT
  - The relevant tariffs for these storage services were used to estimate storage costs
  - Costs included storage, injection and withdrawal charges, plus fuel
- LNG peaking services were assumed to be equal to the cost of incremental service from Distrigas LNG.
  - Costs included the LNG capacity service and LNG charge itself (set at a Gulf Coast price per the tariff)

Non-Gas Costs Summary

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Pipelines	Annual Fixed Cost/MMBtu of Demand	Commodity Rate/MMBtu	Fuel Percent
TETCO+Algonquin	$232.74	$0.088	9.45%
TETCO Storage	$74.40	$0.096	0
TGP	$181.80	$0.15	7.15 %
TGP Storage	$30.45	$0.02	2%
Distrigas LNG	$730.00	Gas Cost*	0

* Commodity rate is the price of gas.

Supply Source Weightings

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- The next step was to determine the appropriate mix of services that a typical LDC would use to fulfill their customer's demand.
- Using actual data from KeySpan and NSTAR we arrived at a set of weightings for the appropriate mix of supply sources(Transportation, LNG and Storage) during each season.

Supply Source Weightings

Winter Type	Pipeline	Storage	LNG	Total
3 Month	76.6%	18.7%	4.7%	100.0%
5 Month	79.6%	15.4%	5.0%	100.0%
6 Month	81.7%	13.7%	4.6%	100.0%
7 Month	83.7%	12.1%	4.2%	100.0%
Annual	85.0%	11.0%	4.0%	100.0%

Allocating Costs to Seasons

- The final step for determining the avoided costs of natural gas demand reductions
- LDCs must reserve capacity in transportation, storage and LNG services for the entire year just to meet demand during the peak winter demand season
  - Thus, demand reducing strategies that are focused on the peak demand months will save LDCs the most money
- We divide the annual avoided cost by the number of months in various definitions of winter
  - This assumes that the avoided cost – demand reduction – occurs during the entire winter season (as defined)

Results

- Show winter and summer avoided costs for different seasonal configurations
  - Winter costs include all fixed costs, allocated to winter and divided by months/winter
  - Summer costs include only gas, plus variable costs
- Capacity costs are flat in real terms reflecting current policy of pipelines eschewing rate cases
- Higher costs of TETCO/AGT reflects tariff differences

Southern NE Wholesale Avoided Costs (2005$/MMBtu)

Year	Annual Avg.	3 Month Winter	9 Month Summer	5 Month Winter	7 Month Summer	6 Month Winter	6 Month Summer	7 Month Winter	5 Month Summer	Peak Dayt
2005	9.66	12.51	8.39	11.15	8.34	10.80	8.32	10.46	8.27	247.01
2006	10.17	13.08	8.86	11.70	8.82	11.34	8.79	10.99	8.74	248.18
2007	9.81	12.68	8.53	11.31	8.48	10.95	8.45	10.61	8.40	247.35
2008	7.71	10.34	6.57	9.07	6.54	8.74	6.52	8.43	6.48	242.54
2009	6.68	9.18	5.61	7.96	5.58	6.97	5.56	7.36	5.53	240.17
2010	$5.90	$8.30	$4.87	$7.39	$4.86	$7.15	$4.85	$6.92	$4.82	238.37
2011	$5.96	$8.38	$4.93	$7.46	$4.92	$7.23	$4.91	$6.99	$4.88	238.52
2012	$6.18	$8.62	$5.14	$7.71	$5.13	$7.47	$5.11	$7.23	$5.08	239.02
2013	$6.38	$8.85	$5.33	$7.94	$5.32	$7.70	$5.30	$7.46	$5.27	239.49
2014	$6.99	$9.52	$5.89	$8.61	$5.87	$8.37	$5.85	$8.12	$5.82	240.87
2015	$6.56	$9.04	$5.49	$8.13	$5.48	$7.89	$5.46	$7.65	$5.42	239.89
2016	$6.58	$9.07	$5.51	$8.16	$5.50	$7.92	$5.48	$7.68	$5.45	239.94
2017	$6.55	$9.03	$5.48	$8.12	$5.47	$7.89	$5.45	$7.64	$5.42	239.87
2018	$6.71	$9.21	$5.63	$8.30	$5.62	$8.06	$5.60	$7.82	$5.56	240.23
2019	$6.90	$9.42	$5.81	$8.51	$5.79	$8.28	$5.77	$8.03	$5.74	240.67
2020	$7.04	$9.58	$5.94	$8.67	$5.92	$8.43	$5.90	$8.18	$5.87	240.99
2021	$7.35	$9.93	$6.23	$9.02	$6.21	$8.78	$6.19	$8.53	$6.15	241.71
2022	$7.45	$10.04	$6.32	$9.13	$6.30	$8.89	$6.28	$8.64	$6.24	241.93
2023	$7.83	$10.45	$6.67	$9.55	$6.65	$9.31	$6.63	$9.06	$6.59	242.79
2024	$7.93	$10.57	$6.76	$9.66	$6.74	$9.42	$6.72	$9.17	$6.68	243.02
2025	$8.43	$11.13	$7.23	$10.23	$7.21	$9.99	$7.19	$9.73	$7.14	244.18

Northern & Central NE Wholesale Avoided Costs (2005$/MMBtu)

Year	Annual Avg.	3 Month Winter	9 Month Summer	5 Month Winter	7 Month Summer	6 Month Winter	6 Month Summer	7 Month Winter	5 Month Summer	Peak Dayt
2005	9.58	11.89	8.26	10.74	8.22	10.44	8.20	10.14	8.15	199.64
2006	10.08	12.45	8.73	11.28	8.68	10.97	8.66	10.66	8.61	200.80
2007	9.72	12.05	8.40	10.90	8.36	10.60	8.33	10.29	8.28	199.98
2008	7.66	9.75	6.49	8.69	6.46	8.42	6.44	8.15	6.40	195.22
2009	6.64	8.61	5.54	7.60	5.52	6.67	5.50	7.09	5.47	192.86
2010	$5.86	$7.75	$4.82	$7.03	$4.80	$6.84	$4.79	$6.64	$4.76	191.07
2011	$5.92	$7.82	$4.88	$7.10	$4.86	$6.92	$4.85	$6.71	$4.82	191.22
2012	$6.14	$8.06	$5.08	$7.34	$5.06	$7.16	$5.04	$6.95	$5.02	191.71
2013	$6.34	$8.28	$5.27	$7.56	$5.24	$7.38	$5.23	$7.17	$5.20	192.18
2014	$6.93	$8.94	$5.82	$8.23	$5.79	$8.04	$5.77	$7.83	$5.74	193.54
2015	$6.51	$8.47	$5.43	$7.75	$5.40	$7.57	$5.38	$7.36	$5.35	192.57
2016	$6.53	$8.50	$5.45	$7.78	$5.42	$7.60	$5.41	$7.39	$5.38	192.62
2017	$6.50	$8.47	$5.42	$7.75	$5.39	$7.56	$5.38	$7.36	$5.35	192.56
2018	$6.66	$8.64	$5.56	$7.92	$5.54	$7.74	$5.52	$7.53	$5.49	192.91
2019	$6.85	$8.85	$5.74	$8.13	$5.71	$7.95	$5.69	$7.74	$5.66	193.35
2020	$6.98	$9.00	$5.87	$8.28	$5.84	$8.10	$5.82	$7.89	$5.79	193.67
2021	$7.29	$9.34	$6.15	$8.63	$6.12	$8.45	$6.10	$8.23	$6.07	194.38
2022	$7.39	$9.45	$6.24	$8.74	$6.21	$8.55	$6.19	$8.34	$6.16	194.60
2023	$7.76	$9.86	$6.58	$9.15	$6.55	$8.97	$6.53	$8.75	$6.49	195.45
2024	$7.86	$9.97	$6.67	$9.26	$6.64	$9.08	$6.62	$8.86	$6.58	195.68
2025	$8.36	$10.53	$7.13	$9.82	$7.10	$9.63	$7.08	$9.41	$7.04	196.83

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Vermont Wholesale Avoided Costs (2005$/MMBtu)

Year	Annual Avg.	3 Month Winter	9 Month Summer	5 Month Winter	7 Month Summer	6 Month Winter	6 Month Summer	7 Month Winter	5 Month Summer	Peak Day
2005	9.66	11.26	7.34	9.95	7.30	9.61	7.28	9.29	7.24	247.01
2006	10.17	11.49	7.53	10.17	7.49	9.83	7.47	9.50	7.42	248.18
2007	9.81	10.20	6.45	8.93	6.42	8.61	6.40	8.30	6.36	247.35
2008	7.71	8.98	5.44	7.76	5.41	7.45	5.39	7.16	5.36	242.54
2009	6.68	8.47	5.01	7.27	4.98	6.97	4.97	6.69	4.94	240.17
2010	5.89	8.30	4.87	7.12	4.85	6.82	4.83	6.54	4.81	238.36
2011	5.95	8.38	4.93	7.19	4.91	6.88	4.89	6.60	4.87	238.51
2012	6.17	8.62	5.14	7.42	5.11	7.11	5.10	6.83	5.07	239.01
2013	6.37	8.85	5.33	7.64	5.30	7.33	5.28	7.04	5.25	239.48
2014	6.98	9.52	5.89	8.28	5.86	7.96	5.84	7.67	5.81	240.86
2015	6.55	9.04	5.49	7.82	5.46	7.51	5.44	7.22	5.41	239.87
2016	6.57	9.07	5.51	7.85	5.48	7.54	5.47	7.25	5.43	239.93
2017	6.54	9.03	5.48	7.82	5.46	7.51	5.44	7.22	5.41	239.86
2018	6.70	9.21	5.63	7.99	5.60	7.67	5.58	7.38	5.55	240.22
2019	6.89	9.42	5.81	8.19	5.78	7.88	5.76	7.58	5.73	240.66
2020	7.03	9.58	5.94	8.34	5.91	8.02	5.89	7.72	5.85	240.98
2021	7.34	9.93	6.23	8.67	6.20	8.35	6.18	8.05	6.14	241.70
2022	7.44	10.04	6.32	8.78	6.29	8.45	6.27	8.15	6.23	241.92
2023	7.82	10.45	6.67	9.18	6.63	8.85	6.61	8.54	6.57	242.78
2024	7.92	10.57	6.76	9.28	6.73	8.96	6.71	8.64	6.67	243.01
2025	8.42	11.13	7.23	9.83	7.20	9.49	7.17	9.17	7.13	244.17

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Estimating Retail Avoided Costs

- Involved mapping winter types to retail sectors
  - Commercial and industrial non-heating – Annual
  - Commercial and industrial heating -- 5 Month
  - Existing residential heating -- 3 Month
  - New residential heating -- 5 Month
  - Residential domestic hot water -- Annual
  - All commercial and industrial -- 6 Month
  - All residential -- 6 Month
  - All retail end uses -- 5 Month
- Allocating LDC avoidable costs to end use sectors
  - Used average retail markups from EIA
  - Assumed 50 percent of retail markup is avoidable

Southern NE Retail Avoided Costs (2005$/MMBtu)

	Residential				Commercial & Industrial			All Retail
Year	Existing Heating	New Heating	Hot Water	All	Non Heating	Heating	All	
2005	12.60	12.49	12.46	12.51	11.17	11.20	11.18	11.92
2006	13.08	12.97	12.97	13.01	11.68	11.68	11.68	12.41
2007	12.64	12.54	12.61	12.60	11.32	11.25	11.28	12.01
2008	10.62	10.52	10.51	10.55	9.22	9.23	9.22	9.95
2009	9.62	9.52	9.47	9.54	8.18	8.23	8.21	8.94
2010	8.89	8.79	8.68	8.79	7.39	7.50	7.44	8.18
2011	8.95	8.85	8.75	8.85	7.46	7.56	7.51	8.25
2012	9.17	9.07	8.97	9.07	7.68	7.78	7.73	8.47
2013	9.38	9.28	9.17	9.28	7.88	7.99	7.93	8.67
2014	9.99	9.88	9.77	9.88	8.48	8.59	8.54	9.28
2015	9.55	9.45	9.35	9.45	8.05	8.16	8.11	8.85
2016	9.58	9.48	9.37	9.47	8.08	8.19	8.13	8.87
2017	9.55	9.45	9.34	9.45	8.05	8.16	8.10	8.84
2018	9.71	9.60	9.50	9.60	8.21	8.31	8.26	9.00
2019	9.90	9.80	9.69	9.80	8.40	8.51	8.45	9.19
2020	10.04	9.94	9.83	9.94	8.54	8.65	8.59	9.33
2021	10.36	10.25	10.14	10.25	8.85	8.96	8.91	9.65
2022	10.46	10.35	10.24	10.35	8.95	9.06	9.00	9.74
2023	10.83	10.73	10.61	10.73	9.32	9.44	9.38	10.12
2024	10.94	10.83	10.71	10.83	9.42	9.54	9.48	10.22
2025	11.45	11.34	11.22	11.34	9.93	10.05	9.99	10.73
2026-40	11.45	11.34	11.22	11.34	9.93	10.05	9.99	10.73
Levelized 2.03%	10.74	10.63	10.54	10.64	9.25	9.34	9.29	10.03

Northern & Central NE Retail Avoided Costs (2005$/MMBtu)

Year	Residential: Existing Heating	Residential: New Heating	Residential: Hot Water	Residential: All	Commercial & Industrial: Non Heating	Commercial & Industrial: Heating	Commercial & Industrial: All	All Retail
2005	12.28	12.19	12.19	12.22	11.31	11.31	11.31	11.81
2006	12.76	12.67	12.70	12.71	11.82	11.79	11.80	12.30
2007	12.33	12.24	12.34	12.30	11.46	11.36	11.41	11.90
2008	10.34	10.25	10.27	10.29	9.39	9.37	9.38	9.88
2009	9.36	9.28	9.25	9.30	8.37	8.40	8.39	8.89
2010	8.63	8.55	8.48	8.55	7.60	7.67	7.63	8.14
2011	8.70	8.62	8.54	8.62	7.66	7.74	7.70	8.20
2012	8.91	8.83	8.75	8.83	7.87	7.95	7.91	8.42
2013	9.12	9.04	8.96	9.04	8.08	8.16	8.12	8.62
2014	9.72	9.63	9.55	9.63	8.67	8.75	8.71	9.22
2015	9.29	9.21	9.13	9.21	8.25	8.33	8.29	8.79
2016	9.31	9.23	9.15	9.23	8.27	8.35	8.31	8.82
2017	9.28	9.20	9.12	9.20	8.24	8.32	8.28	8.79
2018	9.44	9.36	9.28	9.36	8.40	8.48	8.44	8.94
2019	9.63	9.55	9.47	9.55	8.59	8.67	8.63	9.13
2020	9.77	9.68	9.60	9.69	8.72	8.80	8.76	9.27
2021	10.08	9.99	9.91	10.00	9.03	9.11	9.07	9.58
2022	10.18	10.09	10.01	10.09	9.13	9.21	9.17	9.68
2023	10.55	10.46	10.38	10.46	9.50	9.58	9.54	10.05
2024	10.65	10.56	10.47	10.56	9.59	9.68	9.64	10.15
2025	11.15	11.06	10.97	11.06	10.09	10.18	10.14	10.65
2026-40	11.15	11.06	10.97	11.06	10.09	10.18	10.14	10.65
Levelized								
2.03%	10.45	10.37	10.30	10.37	9.42	9.49	9.45	9.96

Vermont Retail Avoided Cost (2005$/MMBtu)

Year	Residential: Existing Heating	Residential: New Heating	Residential: Hot Water	Residential: All	Commercial & Industrial: Non Heating	Commercial & Industrial: Heating	Commercial & Industrial: All	All Retail
2005	11.50	11.42	11.32	11.41	10.29	10.38	10.34	10.93
2006	11.98	11.90	11.80	11.89	10.77	10.87	10.82	11.41
2007	11.64	11.56	11.46	11.55	10.43	10.52	10.48	11.07
2008	9.65	9.58	9.50	9.58	8.46	8.55	8.51	9.10
2009	8.67	8.60	8.53	8.60	7.49	7.57	7.53	8.12
2010	7.93	7.86	7.79	7.86	6.75	6.83	6.79	7.38
2011	7.99	7.92	7.85	7.92	6.81	6.89	6.85	7.44
2012	8.19	8.13	8.05	8.13	7.02	7.09	7.06	7.64
2013	8.39	8.32	8.24	8.32	7.21	7.29	7.25	7.84
2014	8.96	8.89	8.81	8.88	7.77	7.85	7.81	8.40
2015	8.55	8.48	8.41	8.48	7.37	7.45	7.41	8.00
2016	8.57	8.51	8.43	8.50	7.40	7.47	7.43	8.02
2017	8.55	8.48	8.40	8.48	7.37	7.44	7.41	7.99
2018	8.69	8.63	8.55	8.62	7.51	7.59	7.55	8.14
2019	8.88	8.81	8.73	8.80	7.70	7.77	7.73	8.32
2020	9.01	8.94	8.86	8.93	7.82	7.90	7.86	8.45
2021	9.30	9.23	9.15	9.23	8.12	8.20	8.16	8.75
2022	9.40	9.32	9.24	9.32	8.21	8.29	8.25	8.84
2023	9.75	9.68	9.59	9.67	8.56	8.64	8.60	9.19
2024	9.85	9.77	9.69	9.77	8.65	8.74	8.70	9.29
2025	10.32	10.25	10.16	10.25	9.13	9.22	9.17	9.76
2026-40	10.32	10.25	10.16	10.25	9.13	9.22	9.17	9.76
Levelized								
2.03%	9.68	9.61	9.52	9.60	8.49	8.57	8.53	9.12

Uncertainties about Future Costs

- North American gas prices
  - Supply and demand response to current market
  - Long term gas supply response in U.S. and Canada
  - Availability of LNG
  - Climate change regulation and future of gas for power generation
- Shifting capacity towards Dawn away from the Gulf Coast
  - Recent NEGM contracting has tapped Dawn Hub in southwestern Ontario

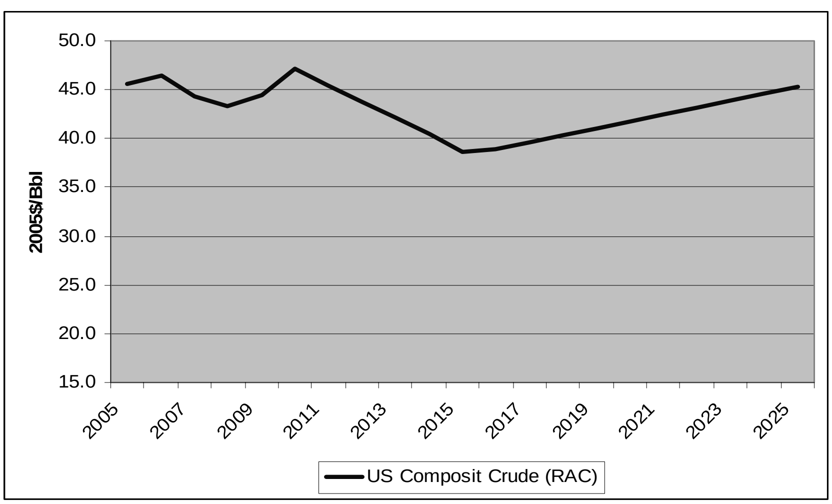
Comparison With Previous Study for 2010 – Wholesale Avoided Cost

2010	AESC 2003		AESC 2005	
	South NE	North/Central NE	South NE	North/Central NE
Annual Average	$5.15	$5.02	$5.90	$5.86
3 Month Winter	$6.74	$6.49	$8.30	$7.75
9 Month Summer	$4.33	$4.30	$4.87	$4.82
5 Month Winter	$6.42	$6.16	$7.39	$7.03
7 Month Summer	$4.23	$4.21	$4.86	$4.80
7 Month Winter	$6.19	$5.95	$6.92	$6.64
5 Month Summer	$4.09	$4.11	$4.82	$4.76

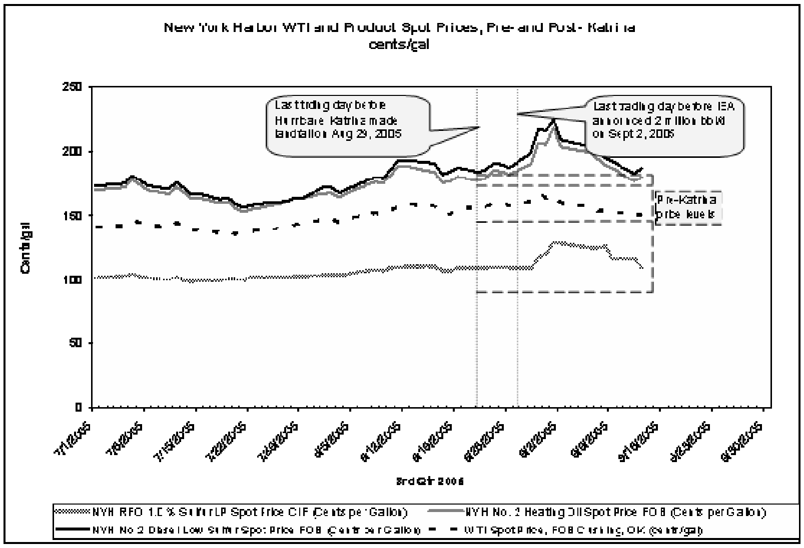
Other Fuels Forecasts

- Other fuels forecasts, except for wood, derive generally from oil prices
- Oil price forecast based on analysis of futures and fundamentals
  - Near term oil markets will remain tight, with an initial decline from recent highs
  - After 2010, new supplies will emerge to meet demand, bringing down oil prices
  - Overall world demand will increase and gradually raise prices
- Oil prices are notoriously susceptible to short term thinking about supply security and episodic disruptions and contain a risk premium not related to fundamentals

Crude Oil Price Forecast



Katrina Impacts on Oil Were Small



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Oil and Product Prices (National)

Year	US Composite RAC Oil Price	US Composite RAC Oil Price	US Average (Base) No.2 Distillate	US Average (Base) No. 6 Resid < 1% S	U.S. Propane (Consumer Grade) Wholesale Price	U.S. Refiners Price of Kerosene
	$/bbl	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
2005	45.60	7.86	9.39	7.25	9.39	9.89
2006	46.40	8.01	9.54	7.40	9.54	10.04
2007	44.40	7.65	9.19	7.05	9.19	9.68
2008	43.30	7.47	9.01	6.87	9.01	9.51
2009	44.50	7.67	9.21	7.07	9.21	9.71
2010	47.20	8.14	9.68	7.54	9.68	10.17
2011	45.50	7.84	9.38	7.24	9.38	9.88
2012	43.80	7.55	9.09	6.95	9.09	9.59
2013	42.10	7.26	8.80	6.66	8.80	9.29
2014	40.40	6.97	8.51	6.37	8.51	9.00
2015	38.60	6.66	8.20	6.06	8.20	8.69
2016	38.90	6.71	8.25	6.10	8.24	8.74
2017	39.60	6.83	8.37	6.23	8.37	8.86
2018	40.30	6.95	8.49	6.35	8.49	8.99
2019	41.00	7.07	8.61	6.47	8.61	9.11
2020	41.70	7.19	8.73	6.59	8.73	9.23
2021	42.40	7.32	8.85	6.71	8.85	9.35
2022	43.10	7.44	8.98	6.84	8.97	9.47
2023	43.80	7.56	9.10	6.96	9.10	9.59
2024	44.60	7.68	9.22	7.08	9.22	9.72
2025	45.30	7.80	9.34	7.20	9.34	9.84

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Electric Power Avoided Costs

Tasks 3 and 4

The Analysis Of Electric Power Avoided Costs Incorporated Several Key Steps

Wholesale Price Forecast	DRIPE Forecast	Retail Cost Components	Transmission and Distribution	Avoided Cost Forecast
• Agree on Assumptions and Methodology • Perform Analysis to Determine Wholesale Average Hourly Price and Producer Cost Forecast • Address Comments on Results	• Agree on Assumptions and Methodology • Perform Analysis to Determine DRIPE effect on wholesale prices • Include DRIPE in the Avoided Cost Estimates		• Develop an approach to include transmission and distribution avoidable capacity costs	• Present Results and Collect Comments for Final Report •Finalize Report
Task 3	Task 3L	Task 3K	Task 4	

Start → End

Key Drivers of Power Prices and Avoided Cost

- Spot market energy prices are impacted by fossil fuel prices and availability, particularly natural gas, and by transmission congestion charges. Environmental allowance also have a significant impact on energy prices.
  - Local infrastructure (transmission) constraints can contribute to high degree of price differentiation across sub-zones.
- Capacity value is dependent on the supply of MW available to serve the peak demand requirements. Capacity value is subject to similar infrastructure issues to energy prices.
  - Capacity prices are subject to an uncertain future in terms of the structure which will be implemented for capacity markets going forward.
  - Dependent on the market design, the value of capacity may not be apparent from the price signal only.
  - Pure capacity value in an equilibrium market is reflective of the return of and on capital that a unit serving the marginal demand need has.
- The individual energy and capacity price drivers are discussed in further detail in the following slides.

Annual Energy Avoided Costs for Select Years By State (2005$/kWh)

Year	CT	MA	ME	NH	RI	VT
2005	0.071	0.065	0.063	0.064	0.065	0.068
2006	0.082	0.074	0.071	0.072	0.075	0.077
2007	0.085	0.077	0.073	0.075	0.077	0.079
2008	0.068	0.065	0.061	0.063	0.065	0.065
2009	0.055	0.052	0.049	0.051	0.052	0.053
2012	0.050	0.049	0.047	0.048	0.049	0.049
2016	0.051	0.051	0.048	0.050	0.050	0.051
2020	0.059	0.058	0.056	0.058	0.058	0.058
2030	0.065	0.065	0.063	0.064	0.065	0.065
2040	0.065	0.065	0.063	0.064	0.064	0.065
Levelized 2005-2040	0.061	0.060	0.057	0.059	0.059	0.060
Levelized 2006-2010	0.068	0.063	0.060	0.062	0.063	0.064
Levelized 2006-2020	0.058	0.056	0.053	0.055	0.056	0.056

Levelized at a 2.03 percent real discount rate.

Annual Capacity Avoided Costs for Select Years By State (2005$/kW-yr)

Year	CT	MA	ME	NH	RI	VT
2005	20.332	6.637	0.000	3.616	3.616	3.616
2006	52.243	40.920	23.304	36.350	36.350	36.350
2007	54.462	45.076	20.172	41.283	41.283	41.283
2008	67.588	63.127	19.462	62.635	62.635	62.635
2009	72.019	67.496	17.895	66.962	66.962	66.962
2012	80.444	76.753	66.810	76.100	76.100	76.100
2016	79.577	80.721	68.230	77.188	77.188	77.188
2020	76.392	78.148	58.896	75.267	75.267	75.267
2030	78.014	79.542	76.468	78.796	78.796	78.796
2040	36.090	36.809	35.718	36.459	36.459	36.459
Levelized 2005-2040	68.041	66.728	51.998	64.964	64.964	64.964
Levelized 2006-2010	63.956	57.086	21.693	55.048	55.048	55.048
Levelized 2006-2020	73.370	70.499	47.760	68.296	68.296	68.296

Levelized at a 2.03 percent real discount rate.

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Annual Energy Avoided Costs for Select Years By State (nominal$/kWh)

Year	CT	MA	ME	NH	RI	VT
2005	0.071	0.065	0.063	0.064	0.065	0.068
2006	0.084	0.076	0.073	0.074	0.076	0.078
2007	0.089	0.081	0.077	0.079	0.081	0.082
2008	0.073	0.069	0.065	0.068	0.069	0.070
2009	0.060	0.057	0.053	0.055	0.057	0.058
2012	0.058	0.057	0.055	0.056	0.057	0.057
2016	0.065	0.065	0.062	0.064	0.064	0.065
2020	0.082	0.081	0.078	0.080	0.081	0.082
2030	0.113	0.113	0.109	0.112	0.113	0.114
2040	0.142	0.141	0.138	0.139	0.140	0.142
Levelized 2005-2040	0.084	0.082	0.079	0.081	0.082	0.083
Levelized 2006-2010	0.074	0.068	0.065	0.067	0.069	0.070
Levelized 2006-2020	0.069	0.067	0.063	0.065	0.066	0.067

Levelized at a 4.33 percent nominal discount rate.

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Annual Capacity Avoided Costs for Select Years By State (nominal$/kW-yr)

ICF CONSULTING

Year	CT	MA	ME	NH	RI	VT
2005	20.332	6.637	0.000	3.616	3.616	3.616
2006	53.419	41.841	23.828	37.167	37.167	37.167
2007	56.941	47.128	21.089	43.161	43.161	43.161
2008	72.253	67.485	20.805	66.958	66.958	66.958
2009	78.723	73.779	19.561	73.196	73.196	73.196
2012	94.002	89.689	78.070	88.926	88.926	88.926
2016	101.645	103.106	87.151	98.594	98.594	98.594
2020	106.659	109.111	82.231	105.089	105.089	105.089
2030	136.067	138.733	133.371	137.432	137.432	137.432
2040	78.633	80.200	77.822	79.437	79.437	79.437
Levelized 2005-2040	93.349	91.551	71.348	89.130	89.130	89.130
Levelized 2006-2010	68.277	60.943	23.159	58.768	58.768	58.768
Levelized 2006-2020	86.543	83.158	56.339	80.560	80.560	80.560

Levelized at a 4.33 percent nominal discount rate.

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Wholesale Power Market Prices Form the Basis for Avoided Costs *Task 3 a-d*

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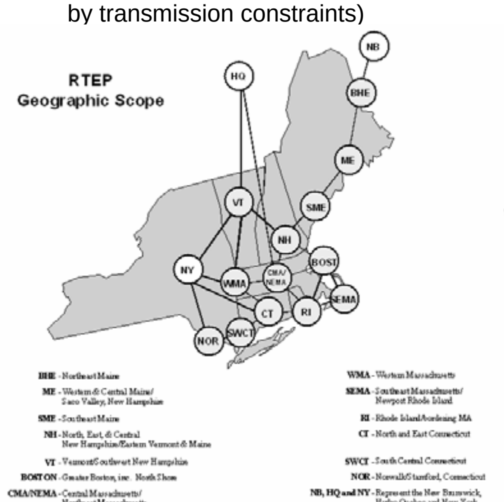
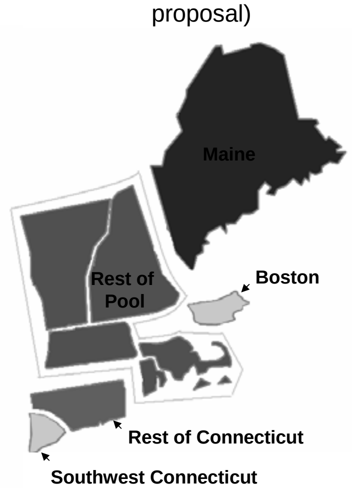
Energy Zones (determined by transmission constraints)



Capacity Zones (as per LICAP proposal)



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Wholesale Energy Prices Reflect Market Fundamentals

- Fuel prices
- Growth in energy demand
- Transmission constraints (energy prices include congestion costs and transmission losses)
- Environmental costs
- New unit operating costs

Load Growth Assumptions are a Key Driver of Potential Avoided Costs

Parameter	New England	Boston	Rest of Connecticut	SWCT	Rest of Pool	Maine
2005 Weather Normalized Net Energy Load (GWh)	126,495	25,139	16,080	16,148	57,182	11,947
Annual Energy Growth						
2005-2006 AAGR	2.0	2.0	2.0	2.1	2.0	1.8
2007-2010 AAGR	1.5	1.5	1.5	1.6	1.6	1.4
2011-2020 AAGR	1.5	1.5	1.5	1.6	1.5	1.3
2021 – forward AAGR	1.6	1.5	1.5	1.7	1.6	1.4

Source: ISO-NE Capacity, Energy Loads and Transmission (CELT) Report April 2005 adjusted to reflect load prior to savings from incremental demand side savings programs.

- Demand and load growth in New England has historically been below the national average growth level.
- Energy and peak demand are both expected to grow slightly less than two percent per year throughout the forecast horizon. The long-term growth rate (post 2014) in New England is roughly 1.5% annually. The U.S. average is approximately 2.5% per year.
- This study accounted for sub-regional differences in growth rates. Some of the faster growing zones include New Hampshire, Southwest Connecticut and Rhode Island. Some of the slower growing regions include Western Massachusetts and Norwalk. The New England RTEP study was used to derive regional growth expectations.

Transmission Constraints Also Play a Key Role

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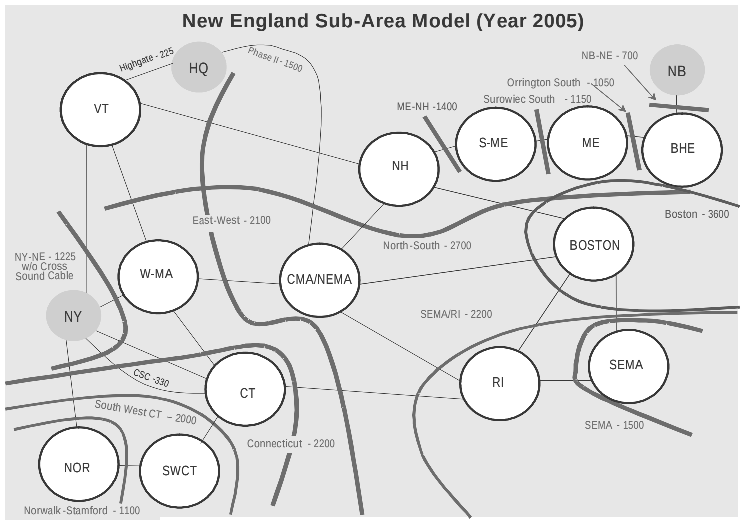


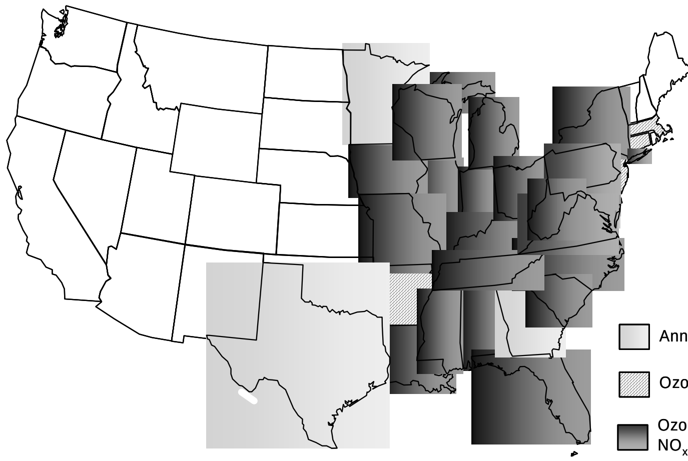
Source: New England RTEP 2004.

Transmission Constraints Also Play a Key Role

ICF CONSULTING

- This study considered all 13 RTEP sub-regions as individual zones. This characterization captures a reasonable set of constraints and transfer potential across areas and as well as major pricing or dispatch differentials across these areas.
- The sub-regions are also interconnected with external power regions including Hydro Quebec and New Brunswick and New York. Transmission flows between these regions will be solved for endogenously.
- In this analysis ICF also considered future transmission developments in the New England region. Some of the major upgrades considered include Phase 1 and Phase 11 of the Southwest Connecticut Reliability Project, the Southern New England Reinforcement Project, the NSTAR 345kV Transmission Reliability Project and the Northeast Reliability Interconnect Project.

Environmental Regulations will Affect Prices - States Affected by the CAIR and Hg Rulings



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Final CAIR and Hg Rule Comparison – NOx Market Outlook

	NOx	
	Proposed	Final
Description	28 States + DC Annual NOx Program	23 State + DC Annual NOx Program plus 25 state + DC Ozone Season NOx Program
Caps	2010: 1.60 Million Tons 2015: 1.33 Million Tons	**Annual Program** 2009: 1.50 Million Tons 2015: 1.25 Million Tons (200,000 ton CSP in 2009) **Ozone Season Program** 2009: 0.568 Million Tons 2015: 0.485 Million Tons
Other Comments	The Phase 1 caps in the final annual and ozone season NOx programs, as well as, the proposed annual NOx program are all based on a 0.15 lb/MMBtu rate decreasing to 0.125 lb/MMBtu in 2015. EPA has proposed including NJ and DE in the annual NOx program. They are currently only in the ozone season program. RI and NH have the option to opt into the ozone season NOx program. SIP Call allowances can be banked into the CAIR Ozone Season NOx program, not into the annual program. In the proposed rule SIP Call allowances could be banked into the annual NOx program.	

- The Clean Air Interstate Rule is modeled in this analysis.
- Under CAIR NOx limitations are imposed on most eastern states under a cap and trade program.
- NOx caps will exist on an annual and seasonal basis.
- NOx caps will begin in 2009 and tighten in 2015.

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Final CAIR and Hg Rule Comparison – SO2 and Hg Market Outlook

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	SO2		Mercury	
	Proposed	Final	Proposed	Final
Description	28 States + DC Annual SO2 Program	23 States + DC Annual SO2 Program	National Annual Cap and Trade Program	National Annual Cap and Trade Program
Caps	Retirement Ratios for Title IV SO2 Allowances 2010: 2:1 2015: 2.86:1	Retirement Ratios for Title IV SO2 Allowances 2010: 2:1 2015: 2.86:1	2010: 34 tons 2018: 15 tons (Safety Valve Hg Price of $35,000/lb)	2010: 38 tons 2018: 15 tons (No Safety Valve Hg Price)
Other Comments	EPA has proposed including NJ and DE in the CAIR SO2 program.			

- SO2, similar to NOx, is controlled under the CAIR rule affecting most eastern states. This implementation affects the allowance trading ratios in the eastern states under Title IV of the Clean Air Act.
- The Clean Air Mercury Rule implements a national tradable tonnage cap for Mercury at 38 tons in 2010 and reducing to 15 tons in 2018.

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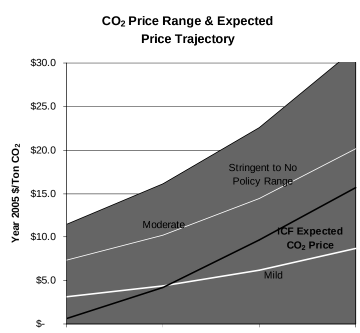
Environmental Regulations will Affect Prices - CO2 Market Outlook

ICF CONSULTING

Build Up of ICF's Expected Case CO_2 Price Trajectory

Year 2005 $/ton CO_2

Prices	2010	2015	2020	2025
Scenario	**2010**	**2015**	**2020**	**2025**
None	$ -	$ -	$ -	$ -
Mild	$ 3.1	$ 4.4	$ 6.2	$ 8.6
Moderate	$ 7.3	$ 10.3	$ 14.4	$ 20.2
Stringent to No Policy Range	$ 11.5	$ 16.1	$ 22.6	$ 31.7
Probabilities				
Scenario	**2010**	**2015**	**2020**	**2025**
None	80%	30%	10%	5%
Mild	20%	50%	45%	40%
Moderate	0%	20%	40%	45%
Stringent to No Policy Range	0%	0%	5%	10%
ICF Expected CO_2 Price	**$ 0.6**	**$ 4.2**	**$ 9.7**	**$ 15.7**



- In addition to the national expected case, a northeast regional CO2 program was considered to be in place as a precursor to the national program.

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Summary of Northeast/Mid-Atlantic (NEMA) RPS Policies impacting New Renewable Generation

Regional Market	State	Incremental (i.e., beyond existing) Standard in 2005 and Later
NEPOOL New York PJM (NEMA)	Connecticut (Class I)	1.5% in 2005 growing to 7% in 2010
	Massachusetts	2% in 2005 growing to 4% in 2009 plus 1% growth per year thereafter
	Rhode Island	3% by 2007, increasing to 4.5% in 2010, increasing to 8.5% in 2014, increasing to 16% in 2019 and thereafter
	New York	1% in 2006 growing to 8% in 2013
	New Jersey (Class I)	0.75% in 2005, 1% in 2006, 4% in 2012
	Pennsylvania (proposed Tier I)	1.5% in 2006 growing by 0.5% per year to 8.0% in 2020 and thereafter.
	Maryland (Tier I)	0.5% in 2006, growing to 7% in 2018

- All renewable market assumptions have been normalized to reflect state requirements for **new** renewable generation. Actual state renewable standards are well above those presented above. For instance, Connecticut, New Jersey, and Maryland have Class II renewable requirements.
- All states allow wind, landfill gas, biomass gasification, fuel cells, geothermal, solar, small hydro, and tidal renewables.
- Note that the PA RPS is prorated by 50% to account for Midwest ISO and existing renewable expected contribution to meeting RPS standard. In addition, the requirement has been prorated to take into account the solar tier component. The resultant RPS begins at 0.75% in 2006 and grows to 3.75% in 2020 and thereafter.

New Unit Performance and Operating Costs will Affect Future Energy Prices

On-line Year	Combined Cycle	Cogen	Combustion Turbine	LM 6000
2010	6,800	6,144	10,547	9,265
2015	6,672	5,976	10,321	9,066
2020	6,553	5,813	10,100	8,872
2025	6,447	5,653	10,100	8,719
2030	6,342	5,653	10,100	8,719

- Over-time, technological improvements are anticipated such that new units coming on will be more efficient than prior vintages of similar unit types. As units come on, these newer units will tend to reduce overall energy prices.

Post-Katrina Natural Gas Price Forecast Update Moves Energy Price Projections Up 28 Percent

Year	Initial Forecast			Revised Forecast		Percent Change
	Gas Price (2005$/ mmbtu)	Implied Heat Rate (btu/kWh)	Energy Price (2005$ /MWh)	Gas Price (2005$/ mmbtu)	Energy Price (2005$ /MWh)	Gas and Energy Price
2005	6.89	8,259	56.9	7.88	65.1	14%
2006	6.50	8,935	58.1	8.33	74.5	28%
2007	5.38	9,645	51.8	8.02	77.3	49%
2008	4.44	10,489	46.6	6.16	64.7	39%
2009	4.39	9,904	43.5	5.25	52.0	20%
2010	4.55	9,926	45.2	4.55	45.2	0%
Levelized 2006-2010	5.07	NA	49.2	6.50	63.1	28%

Levelized at a 2.03 percent real discount rate.

- A near-term adjustment was made to the energy price forecast to account for the affect of the hurricane Katrina on natural gas production and distribution in the gulf. This adjustment affected the near-term only. The adjustment was an off-line adjustment from the existing modeling runs holding the implied heat rate flat. An off-line adjustment was used as the report was near completion at the time of the meeting. Note, the changes were made regionally and by time of day; Rhode Island is shown for explicative purposes.

Annual Wholesale Energy Price for Select Years By State (2005$/kWh)

Year	CT	MA	ME	NH	RI	VT
2005	0.071	0.065	0.063	0.064	0.065	0.068
2006	0.082	0.074	0.071	0.072	0.075	0.077
2007	0.085	0.077	0.073	0.075	0.077	0.079
2008	0.068	0.065	0.061	0.063	0.065	0.065
2009	0.055	0.052	0.049	0.051	0.052	0.053
2012	0.050	0.049	0.047	0.048	0.049	0.049
2016	0.051	0.051	0.048	0.050	0.050	0.051
2020	0.059	0.058	0.056	0.058	0.058	0.058
2030	0.065	0.065	0.063	0.064	0.065	0.065
2040	0.065	0.065	0.063	0.064	0.064	0.065
Levelized 2005-2040	0.061	0.060	0.057	0.059	0.059	0.060
Levelized 2006-2010	0.068	0.063	0.060	0.062	0.063	0.064
Levelized 2006-2020	0.058	0.056	0.053	0.055	0.056	0.056

Levelized at a 2.03 percent real discount rate.

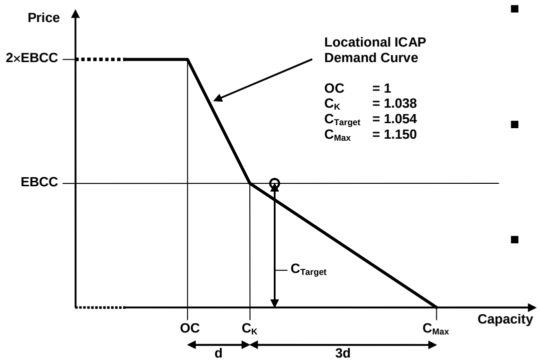
Annual Wholesale Energy Prices By State (continued)

- The energy price forecast is very closely tied to the gas price forecast. The energy prices are very strong throughout the forecast given the dominance of oil and gas fired generation in the New England region.
- The near-term prices in particular are very strongly tied to the gas price forecast. New unit efficiency and environmental policies only play a role in the mid to long-term as new units come online to meet growing demand and environmental polices become more stringent.
- On a zonal level, in the near-term, energy prices are higher in the import constrained regions of Norwalk, Southwest Connecticut and Norwalk. Overall, prices also tend to be higher in zones west of the East/West constraint.

Wholesale Capacity Prices Also Reflect Market Fundamentals

- Market design (ICAP / LICAP / Bundled or others) – this analysis assumes that a LICAP market structure will exist going forward.
- Transmission constraints – under LICAP, locational value is created due to transmission constraints. In the most extreme cases, constraints will strand megawatts or will isolate load resulting in very low or very high capacity value respectively.
- Growth in peak demand
- New unit costs

New England ISO Proposed Demand Curve



EBCC = Estimated Benchmark Capacity Cost
C = Capacity
OC = Objective Capability
C_{Max} = The Capacity at which price equals 2 * EBCC
C_{Target} = Target long-run average capacity
C_K = Capacity at the kink in the demand curve
d = C_k - OC

- The newly proposed capacity demand curves are intended to allow the markets to settle at a reliability level consistent with the willingness to pay for reliability.
- Maine, Connecticut, NEMA/Boston, Southwest Connecticut, and Rest-of-Pool NEPOOL have a proposed locational ICAP market with a demand curve price mechanism.
- This analysis included the use of demand curves in January 2006. The latest FERC decision to delay the implementation of LICAP until no earlier than October 1, 2006, came toward the end of this study. We do not believe this decision would have significant impact on the total avoided capacity payments.

Peak Demand Growth Assumptions

Parameter	New England	Boston	Rest of Connecticut	SWCT	Rest of Pool	Maine
2005 Net Internal Demand[1] (MW)	26,400	5,434	3,516	3,605	11,859	1,986
Annual Peak (and NID) Growth						
2005-2006 AAGR	2.5	2.6	2.4	2.3	2.7	2.4
2007-2010 AAGR	1.5	1.5	1.4	1.3	1.6	1.4
2011-2020 AAGR	1.4	1.5	1.3	1.3	1.5	1.3
2021 – forward AAGR	1.6	1.6	1.4	1.4	1.7	1.4

1. Net internal demand (NID) is equal to the peak load less interruptible load and direct control load management.

Source: ISO-NE Capacity, Energy Loads and Transmission (CELT) Report April 2005 adjusted to reflect load prior to savings from incremental demand side savings programs.

- Demand growth in New England has historically been below the national average growth level. The long-term growth rate (post 2014) in New England is roughly 1.5% annually. The U.S. average is approximately 2.5% per year.
- This study accounted for sub-regional differences in growth rates. Some of the faster growing zones include New Hampshire, Southwest Connecticut and Rhode Island. Some of the slower growing regions include Western Massachusetts and Norwalk. The New England RTEP study was used to derive regional growth expectations.

Technology Costs will Drive Both Capacity and Energy Value

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	CC / Cogen	Combustion Turbine	LM6000	Wind
New Plant All-In Levelized Capital Cost (2005$/kW)				
Connecticut	855	574	1018	1906
Boston	914	606	1041	1969
Southwest Connecticut	892	596	1035	-
Rest of Pool	837	560	974	1844
Maine	792	547	960	1722
Financing Costs for New Unplanned Builds	CC / Cogen	CT/LM6000		Wind
Debt/Equity Ratio (%)	45/55	30/70		45/55
Nominal Debt Rate (%)	8	9		8
Nominal After Tax Return on Equity (%)	13	13		13
Income Taxes[1] (%)	41.0/39.9/40.8	41.0/39.9/40.8		41.0/39.9/40.8
Other Taxes[2,3] (%)	1.34/1.23/1.09	1.34/1.23/1.09		1.34/1.23/1.09
General Inflation Rate (%)	2.3	2.3		2.3
Levelized Real Capital Charge Rate[2] (%)	**13.1/12.9/12.8**	**14.3/14.1/14.1**		**13.7/13.5/13.4**

1. Production tax and other tax credits assumed to be available through 2009 and are included directly in the capital costs or capital charge rate.

2. Includes state taxes of 7.5, 8.9, 9.5, 8.5, 9.0 and 9.75 percent in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont respectively.

3. Includes insurance costs of 0.3 percent for all the sub-regions.

Technology Costs will Drive Both Capacity and Energy Value

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- Average New England capital costs start at over $800/kW (real 2005$) for combined cycles and cogeneration facilities, at roughly $564/kW (real 2005$) for combustion turbines and at roughly $1000/kW (real 2005$) for LM 6000s. These capital costs remain flat over the forecast period.
- Costs vary regionally within New England based on labor and site costs as well as temperature and altitude adjustments. In particular, costs are highest in Connecticut and Boston and lowest in Maine.
- The build mix will be determined through economics for units allowed. New coal facilities are not permitted in the New England marketplace.

Annual Wholesale Market Capacity Prices for Select Years By State (2005$/kW-yr)

Year	CT	MA	ME	NH	RI	VT
2005	6.783	3.908	0.000	2.662	2.662	2.662
2006	48.378	34.873	23.304	34.548	34.548	34.548
2007	51.479	39.500	20.172	39.132	39.132	39.132
2008	65.040	63.019	19.462	62.436	62.436	62.436
2009	69.546	67.385	17.895	66.758	66.758	66.758
2012	78.325	76.681	66.810	75.967	75.967	75.967
2016	79.577	80.721	68.230	77.188	77.188	77.188
2020	76.392	78.148	58.896	75.267	75.267	75.267
2030	78.014	79.542	76.468	78.796	78.796	78.796
2040	36.090	36.809	35.718	36.459	36.459	36.459
Levelized 2005-2040	66.745	66.167	51.998	64.742	64.742	64.742
Levelized 2006-2010	61.095	54.628	21.693	54.120	54.120	54.120
Levelized 2006-2020	71.811	69.578	47.760	67.922	67.922	67.922

Levelized at a 2.03 percent real discount rate.

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Annual Realized Out of Market Cost for Select Years By State (2005$/kW-yr)

Year	CT	MA	ME	NH	RI	VT
2005	13.549	2.728	0.00	0.954	0.954	0.954
2006	3.865	6.047	0.00	1.801	1.801	1.801
2007	2.983	5.576	0.00	2.151	2.151	2.151
2008	2.547	0.108	0.00	0.199	0.199	0.199
2009	2.473	0.111	0.00	0.204	0.204	0.204
2012	2.119	0.072	0.00	0.133	0.133	0.133
2016	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00
Levelized 2005-2040	1.191	0.558	0.00	0.215	0.215	0.215
Levelized 2006-2010	2.858	2.458	0.00	0.927	0.927	0.927
Levelized 2006-2020	1.348	0.913	0.00	0.360	0.360	0.360

Levelized at a 2.03 percent real discount rate. Rest of Pool out of Market Costs are distributed equally across the RTEP zones.

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Annual Wholesale Capacity Value and Out-of-Market Costs Comprise the Avoided Capacity Value

- As discussed earlier, the capacity price in this forecast is reflected under the locational ICAP zones as per the current LICAP proposal. These zonal prices (Maine, Boston, Southwest Connecticut, Rest of Connecticut, and Rest of Pool) have been aggregated to the state level for presentation purposes.
- This analysis projected that several units, despite receiving LICAP revenues, would not earn significant capacity compensation to allow those units to continue operation. ICF did not do a full determination of need assessment or voltage support / reliability; however, based on public information, ICF determined which of those margin units would be eligible for a cost-of-service recovery and included these costs in the avoided cost forecast as "out-of-market" costs. These units were located in primarily in Southwest Connecticut and Boston, and additionally in SEMA and Western Massachusetts. Note, only those units eligible for cost recovery were considered to have costs which could be avoided.
- The LICAP status has stalled somewhat since the inception of this project. Ultimately LICAP may take an alternate for to that proposed. However, as the all-in avoided cost forecast allows for cost-recovery for both new and existing units, it is reflective of the value one would expect under a competitive market design.

Costs of Serving Retail Load above the Wholesale Power Costs are not Considered as Avoidable

- In this analysis, other costs typically considered as the costs of serving load, are not considered avoidable. The full exclusion of these costs is conservative, however, it is expected that typical DSM savings programs will not result in significant reductions.
  - Customer Account Expenses and Customer Service Expenses – it is anticipated that the number of customers will not be affected, rather the load per customer. Hence customer expenses are excluded.
  - Sales Costs – Sales costs include advertising expenses were assumed not to change with reductions in peak demand.
  - General Managerial and Administrative Expenses – G&A expenses include office supplies, insurance, franchise fees, pension and benefit costs, etc.. which are assumed not to change with reductions in peak demand.
  - Line Maintenance Expense – Transmission and distribution line maintenance costs are assumed to include items such as vehicles, employee wages, and equipment such as line monitoring equipment. These costs are also considered to be independent of the avoidance of peak load for existing lines.
- Additional items such as stranded costs recovery and fixed costs or retail operations are not considered in the avoided costs presented although they would be considered in retail rates.

Massachusetts Retail Multiple - *Task 3K*

Source	Period	New England	Massachusetts
AEO 2005	2002-2003 (historical)	1.7	n/a
EIA 826	2003-2004	2.0	2.0
FERC FORM 1	2002-2004	n/a	1.4
AVERAGE		**1.9**	**1.7**

Source: Calculated as the price increment over the ISO reported energy and capacity price.

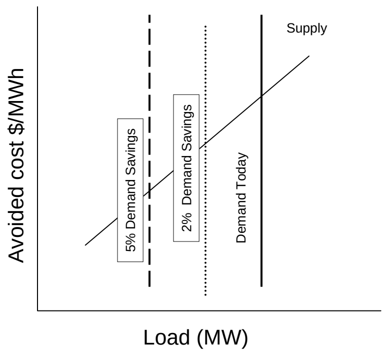
- Task 3k under the original AESC RFP included a calculation for the retail adder in Massachusetts. ICF utilized information reported on the EIA form 826 and the FERC Form 1 to estimate the retail adder for Massachusetts only. This resulted in an estimate of 1.7x the wholesale price.

Costing Periods *Tasks 3e and 3f*

States	Season	Peak Period
CT	Summer – June through September; Winter – All other months	7 a.m. to 10 p.m. weekdays
All other states	Summer – June through August; Winter – All other months	7 a.m. to 10 p.m. weekdays

- The costing periods used in this analysis varied slightly from the ICF recommendation. Instead the costing period used in the 2003 study was maintained as it was determined that the implementation barriers outweighed the slight variations between costing periods. The Costing periods used for this analysis are shown in the table to the left.
- ICF's costing period recommendation analyzed 2005 forecast data. Historical data was also analyzed in reviewing costing period.
- A hour of the day was considered to be peak if more than 50 percent of the prices that occurred over for that hour of the day were greater than the annual mean. This resulted in slight deviations in hour type definitions than what was used for the analysis.
- To determine the seasonal characterization, ICF examined the monthly average prices and volatility across regions. While the summer months typically had lower average prices, they tended to have twice as much volatility as the winter months. ICF used this criteria to determine the seasonal characterization.

Electric Demand Reduction Induced Price Effects (DRIPE) *Task 3L* - Demand Savings Programs May Reflect Alternate Savings



- Initially the DRIPE was considered under multiple scenarios examining alternate reductions (or increases) in the Reference Case load projection due to demand response. It was determined that the scenario most relevant to consider was a case with 0.75% peak load reduction.
- Peak capacity price shifts only were measured using this scenario.
- The levelized savings over multiple year periods are shown.

Annual DRIPE for Select Years By State (2005$/kW-yr)

Year	CT	MA	ME	NH	RI	VT
Levelized 2005-2040	185.6	245.8	134.9	320.0	320.0	320.0
Levelized 2006-2010	219.2	446.3	450.2	595.6	595.6	595.6
Levelized 2006-2015	236.2	315.2	237.1	424.6	424.6	424.6
Levelized 2006-2020	249.9	308.4	166.5	416.9	416.9	416.9

Levelized at a 2.03 percent real discount rate.

Annual Alternative DRIPE for Select Years By State (2005$/kW-yr)

Year	CT	MA	ME	NH	RI	VT
Levelized 2005-2040	42.19	24.48	13.49	32.00	32.00	32.00
Levelized 2006-2010	88.28	44.59	45.02	59.56	59.56	59.56
Levelized 2006-2015	94.22	31.50	23.71	42.46	42.46	42.46
Levelized 2006-2020	72.80	30.83	16.65	41.69	41.69	41.69

Levelized at a 2.03 percent real discount rate.

- The Alternate DRIPE scenario considers that demand reductions will only impact capacity traded in the spot markets. This is estimated to be approximately 10 percent of the capacity transactions based on historical activity in the ISO-NE ICAP market and activity in the NY-ISO existing LICAP market.

Transmission and Distribution Avoided Capacity Cost Methodology *Task 4*

- The avoided cost is reflected in the savings associated with deferred T&D investment.

$$= \frac{\$ \sum\left[\frac{Capex}{(1+d)^n} - \frac{Capex * (1 + esc)^{\Delta n}}{(1+d)^{n+\Delta n}}\right] * \text{Capital Charge Rate}}{\text{Change in Load (kW)}}$$

- ICF has provided an adaptable spreadsheet methodology for determining transmission and distribution avoided costs.

Comparison of New England Retail Avoided Electricity Levelized Cost Estimates

ICF CONSULTING

	Current Analysis (2005$/MWh)	Previous Analysis (2005$/MWh)	Delta in $/MWh
Annual All-Hours Price Annuity (2005-2012)	$66.48	$61.24	+5.24 (+8.6%)
Seasonal On – Peak Annuity (2005-2037)			
Summer	$72.33	$75.51	-$3.18 (-4.2%)
Winter	$67.24	$51.68	+$15.56 (+30.1%)
Seasonal Off – Peak Annuity (2005-2037)			
Summer	$47.79	$40.52	+$7.27 (+17.9%)
Winter	$55.31	$40.43	+$14.88 (+36.8%)

Notes: Levelized (annuity) values were calculated using a 2.03 percent discount rate as per the Massachusetts Regulatory Agency standard. Previous analysis inflated to 2005 dollars from 2004 dollars using a 2.25% annual inflation rate assumption. Retail Avoided Costs do not include Transmission and Distribution, note, the previous analysis included some costs in addition to wholesale market costs while the current analysis does not (the additional costs were the equivalent of a multiple of 1.23 above the wholesale costs for all of New England). DRIPE is not included in the values shown.

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Comparison of New England Retail Avoided Electricity Levelized Cost Estimates Excluding Retail Adder

ICF CONSULTING

	Current Analysis (2005$/MWh)	Previous Analysis (2005$/MWh)	Delta in ($/MWh)
Annual All-Hours Price Annuity (2005-2012)	$66.48	$49.79	+$16.69 (+33.5%)
Seasonal On – Peak Annuity (2005-2037)			
Summer	$72.33	$61.39	+$10.94 (+17.8%)
Winter	$67.24	$42.02	+$25.22 (+60.0%)
Seasonal Off – Peak Annuity (2005-2037)			
Summer	$47.79	$32.94	+$14.85 (+45.1%)
Winter	$55.31	$32.87	+$22.44 (+68.3%)

Notes: Levelized (annuity) values were calculated using a 2.03 percent discount rate as per the Massachusetts Regulatory Agency standard. Previous analysis inflated to 2005 dollars from 2004 dollars using a 2.25% annual inflation rate assumption. Retail Avoided Costs do not include Transmission and Distribution or retail cost adder. DRIPE is not included in the values shown.

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Comparison of New England Retail Avoided Electricity Cost Estimates

Year	Current Analysis (2005$/MWh)	Previous Analysis (2005$/MWh)	Delta ($/MWh)
2005	$67.45	$63.07	$4.38
2006	$80.48	$60.61	$19.87
2007	$83.48	$60.81	$22.67
2008	$71.90	$61.01	$10.89
2009	$59.63	$61.03	($1.40)
2010	$53.11	$61.05	($7.94)
2011	$55.26	$61.08	($5.82)
2012	$57.55	$61.10	($3.55)
Levelized 2005-2012 @ 2.03%	$66.48	$61.24	$5.24

Notes: Levelized (annuity) values were calculated using a 2.03 percent discount rate as per the Massachusetts Regulatory Agency standard. Previous analysis inflated to 2005 dollars from 2004 dollars using a 2.25% annual inflation rate assumption. Retail Avoided Costs do not include Transmission and Distribution, note, the previous analysis included some costs in addition to wholesale market costs while the current analysis does not (the additional costs were the equivalent of a multiple of 1.23 above the wholesale costs for all of New England). DRIPE is not included in the values shown.

Seasonal Comparison of New England Retail Avoided Electricity Cost Estimates

Year	On-Peak				Off-Peak			
	Current Analysis (2005$/MWh)		Previous Analysis (2005$/MWh)		Current Analysis (2005$/MWh)		Previous Analysis (2005$/MWh)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2006	84.77	86.05	74.60	53.44	59.90	72.37	42.24	44.36
2008	78.14	74.70	72.08	52.35	50.63	60.48	41.79	41.99
2013	61.46	57.00	75.89	51.21	38.72	45.81	39.54	39.25
2018	67.31	61.75	77.70	52.71	43.42	50.57	40.77	40.50
2025	76.12	68.78	78.81	52.16	50.65	57.08	41.24	40.63
2030	80.48	72.22	79.94	53.80	54.18	60.03	42.34	41.78
2037	79.58	72.18	80.60	53.80	53.10	58.94	42.34	41.78
Levelized 2005-2037 @ 2.03%	72.33	67.24	75.51	51.68	47.79	55.31	40.52	40.43

Notes: Levelized (annuity) values were calculated using a 2.03 percent discount rate as per the Massachusetts Regulatory Agency standard. Previous analysis inflated to 2005 dollars from 2004 dollars using a 2.25% annual inflation rate assumption. Retail Avoided Costs do not include Transmission and Distribution, note, the previous analysis included some costs in addition to wholesale market costs while the current analysis does not (the additional costs were the equivalent of a multiple of 1.23 above the wholesale costs for all of New England). DRIPE is not included in the values shown.

Why do the studies differ?

- Near-term energy market prices differ largely due to gas price assumptions.
- Capacity prices in the current analysis reflect the LICAP market design unlike the prior analysis.
- Retail cost items are not included as avoidable in the current analysis. The previous analysis considered some share of the costs as avoidable.

For More Information

Please Contact:

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Commission Data Request 1-6

Request:

Please bring to the Technical Session at least 9 copies of the responses to the July 12, 2005 data request 3 which asked, "Has Narragansett or the DSM Collaborative considered offering a DSM program to owners/operators of drinking water and/or wastewater facilities as part of its DSM programs? If not, would the DSM Collaborative be willing to research the development of such a program? Please elaborate where necessary."

Response:

The Company will bring 9 copies of the responses to the July 12, 2005 data request 3 to the Technical Session.

Prepared by or under the supervision of: Michael McAteer

Commission Data Request 1-7

Request:

Please be prepared to discuss more fully the section of Attachment 1 entitled "Public Education Initiative.

Response:

Laura McNaughton, Manager of Residential Energy Efficiency, will be available to discuss the Public Education Initiative at the October 28th Technical Session.

Prepared by or under the supervision of: Laura G. McNaughton