Synapse
Energy Economics, Inc.

Electricity Cost Highlights of Avoided Energy Supply Costs in New England 2007 Final Report

Briefing to NSTAR

October 5, 2007

AGENDA

10:00	*Introductions*
10:10	*Background and Overview of Avoided Costs*
	– *AESC Study Group*
	– *Prior Reports*
	– *Avoided Cost Components*
	– *2007 AESC Results*
10:30	*Projections*
	– *Avoided Electric Energy Costs*
	– *Avoided Electric Capacity Costs*
	– *Demand Reduction Induced Price Effects (DRIPE)*
	– *CO2 Environmental costs*
11:30	*General Questions*
12:00	*Wrap-up*

Background - 2007 AESC Study Group

- *Berkshire Gas Company*
- *KeySpan Energy Delivery New England (Boston Gas Company, Essex Gas Company, Colonial Gas Company, and EnergyNorth Natural Gas, Inc.)*
- *Cape Light Compact*
- *National Grid USA*
- *New England Gas Company*
- *NSTAR Electric & Gas Company*
- *New Hampshire Electric Co-op*
- *Bay State Gas and Northern Utilities,*
- *Northeast Utilities (Connecticut Light and Power, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and Yankee Gas)*
- *Unitil (Fitchburg Gas and Electric Light Company and Unitil Energy Systems, Inc.)*
- *United Illuminating*
- *Southern Connecticut Gas and Connecticut Natural Gas,*
- *State of Maine*
- *State of Vermont*
- *Connecticut Energy Conservation Management Board*
- *Massachusetts Department of Public Utilities*
- *Massachusetts Division of Energy Resources*
- *Massachusetts Low-Income Energy Affordability Network (LEAN)*
- *New Hampshire Public Utilities Commission*
- *Rhode Island Division of Public Utilities and Carriers.*

Background - Prior Reports

1999	*Resource Insight & Synapse. Direct components of avoided costs of electricity and natural gas.*
2001	*Resource Insight & Synapse. New - Retail adder.*
2003	*ICF. New - Avoided costs of other fuels.*
2005	*ICF. New – Locational Installed Capacity Prices (LICAP) and DRIPE*
2007	*Synapse, Resource Insight & Swanson Energy Group. New – Forward Capacity Market (FCM) and CO_2 environmental factor*

Background
Avoided Electricity Cost Components

Avoided energy costs = (wholesale energy + Renewable Portfolio Standard or "RPS" compliance) adjusted for retail adder

Avoided capacity costs = (wholesale capacity) adjusted for retail adder and losses on ISO-NE

DRIPE-energy and DRIPE-capacity

CO_2 environmental cost factors

program administrators

- *can set RPS compliance costs, retail adder and losses on ISO-NE*
- *should calculate and adjust for losses from the ISO delivery points to the end use for their specific system*
- *should calculate and adjust for avoided transmission and distribution costs for their specific system*

Background
AESC 2007 Results (cents/kwh) – Boston zone

Current prices for retail electricity supply to residential customers
10 cents/kwh to 11 cents/kwh

AESC 2007 Results, Boston zone, Summer Peak (15 year levelized, constant 2007$)

Avoided energy costs	*10.1*
Avoided capacity costs ($107.30 per kw-year @ 55% LF)	*2.2*
DRIPE- energy	*1.6*
DRIPE- capacity ($ 22.80 per kw-year @ 55% LF)	*.4*
CO2 environmental cost	*3.1*

Projections

- *Avoided Electric Energy Costs*
- *Avoided Electric Capacity Costs*
- *Demand Reduction Induced Price Effects (DRIPE)*
- *CO2 Environmental costs*

Modeling Framework

- Electric supply price forecasting was done using Market Analytics, a simulation and database management module developed and licensed by Global Energy Decisions, a leading industry information and solutions company.

- Market Analytics is based on the PROSYM simulation engine.

- Market Analytics is licensed with Global Energy's NERC database which includes detailed data for generation, load and transmission components of the electricity generation system for North America.

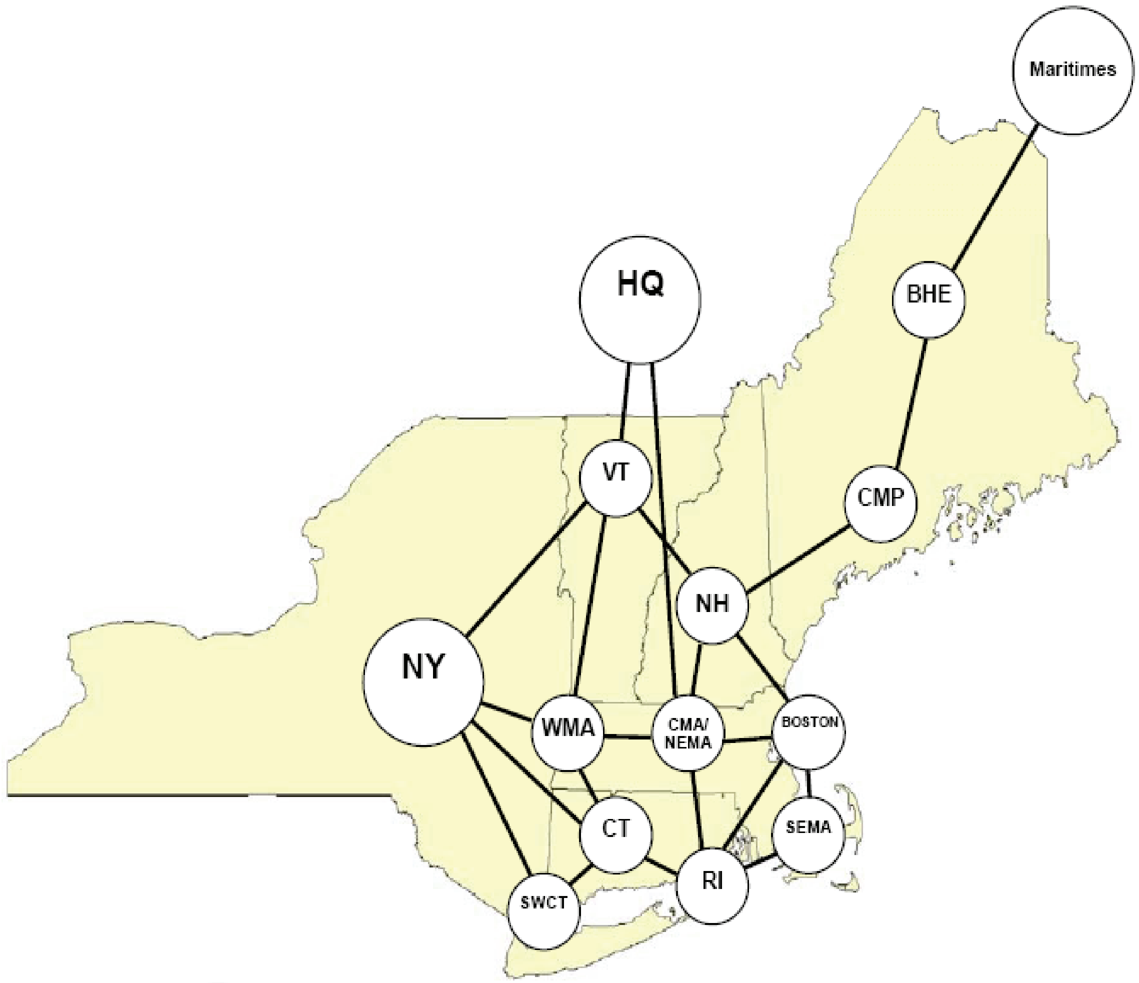
Electric System Representation

- Topology
- Load
- Thermal Unit Characteristics
- Conventional Hydro and Pumped Storage Units
- Fuel Price Forecasts
- Transmission System Representation
- Environmental Regulations
- Demand Response Resources
- Market Model Assumptions

Topology

Based on the topology used for ISO-NE RSP 2006 with two exceptions:

1. SME and ME combined to form CMP
2. Norwalk included in the rest of SWCT



Generator Representation

- Unit type (steam-cycle, combined-cycle, simple-cycle, cogeneration, etc)
- Heat rate values and curve
- Seasonal capacity ratings (maximum and minimum)
- Variable operation and maintenance costs
- Fixed operation and maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick start and spinning reserves capabilities
- Startup costs
- Ramp rates
- Emission rates (SO_2, NO_x, CO_2, and mercury)

Key Input Categories

- Load
- New resource additions
- Emission price forecasts
- Fuel Prices

Load

- Based on 2007 ISO-NE CELT Forecast
- ISO-NE load forecast does not include any incremental DSM savings after 2006
- Consistent with the purpose of this study which is to estimate avoided costs of DSM programs

New Resources

- Planned Additions—Near-term proposed new additions and uprates to existing plants that are in development or advanced stages of permitting and have a high likelihood of reaching commercial operation;
- RPS Additions—Renewable generators that are added to meet existing or anticipated renewable portfolio standards (RPS) in each state; and,
- Generic Additions—New generic conventional resources that are added to meet the residual capacity need after adding planned and RPS additions.

New Resources (cont'd) – RPS Additions

- RPS resources distributed throughout the region consistently with geographic distribution of proposed renewable projects in the ISO-NE queue.
- RPS resource mix is 65% wind, 33% biomass, 1% LFG, and 1% solar PV.

New Resources (cont'd) - Generic Additions

- Generic additions are added to meet a system-wide reserve margin target of 14.3%
- Generic additions are gas/oil CCs and CTs
- Dispersed geographically based on distribution of proposed CC and CT projects in the ISO-NE queue.

Emissions Allowance Price Forecasts

- Modeling include price forecasts for SO_2, NO_x, Hg and CO_2
- Price forecasts for SO_2, NO_x and Hg are based upon experience with existing regulations
- Price forecast for CO_2 assumes Regional Greenhouse Gas Initiative (RGGI) will be in effect in 2009 and will be replaced by national regulations for CO_2 in 2012.

Emission Allownace Price Forecasts (cont'd)

Exhibit 5-11. Allowance Prices for SO_2, NO_x, Mercury (Hg) and CO_2 (2007$)

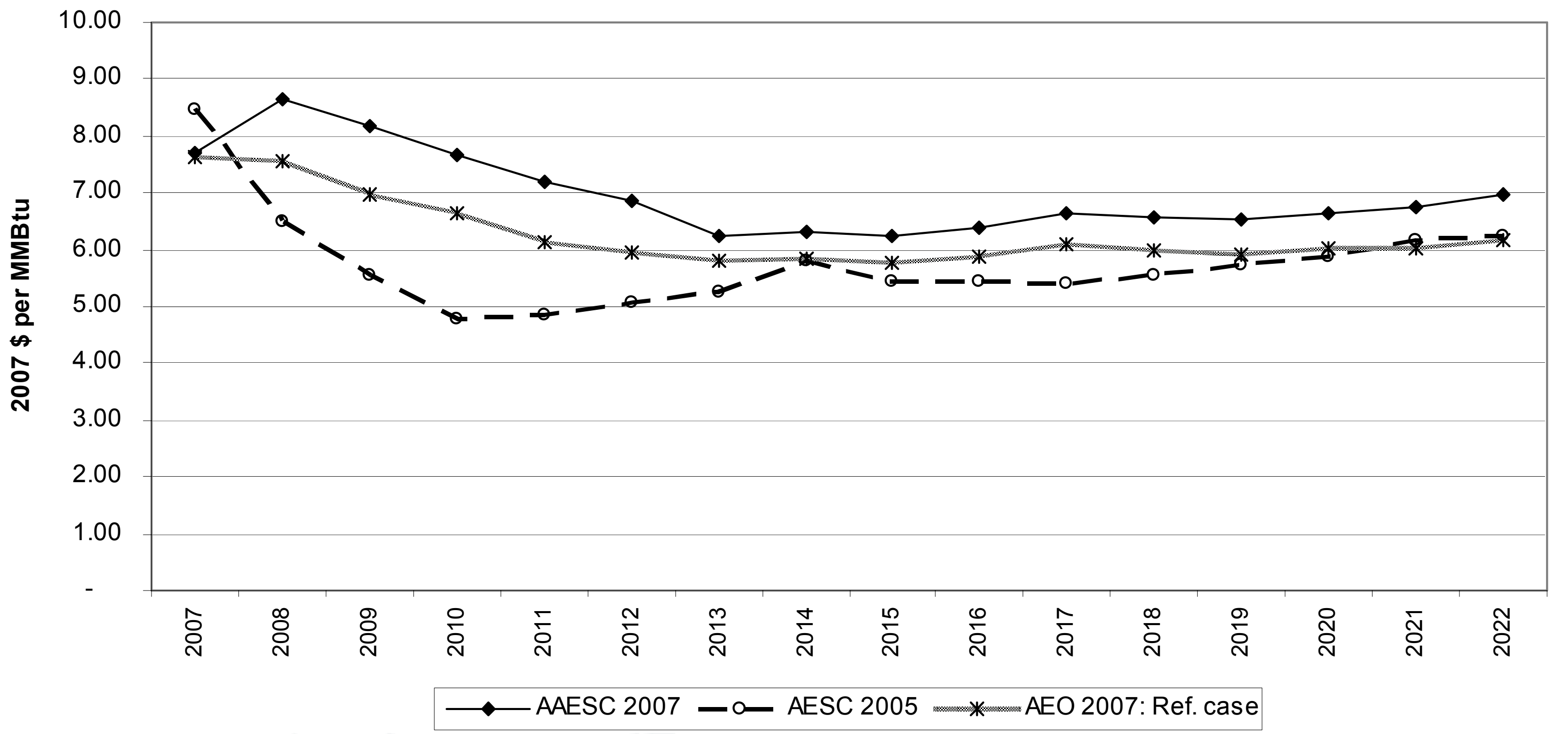
Year	SO2 $/ton	NOx $/ton	Mercury $million/ton	CO_2 $/ton
2007	$434	$1,013	$0.00	$0.00
2008	$433	$925	$0.00	$0.00
2009	$432	$800	$0.00	$2.21
2010	$470	$1,171	$12.66	$2.37
2011	$526	$1,715	$12.66	$2.53
2012	$563	$1,750	$12.66	$9.46
2013	$590	$1,750	$12.66	$11.56
2014	$610	$1,750	$12.66	$13.66
2015	$750	$1,750	$12.66	$15.76
2016	$750	$1,750	$12.66	$17.86
2017	$750	$1,750	$12.66	$19.96
2018	$750	$1,750	$12.66	$22.06
2019	$750	$1,750	$12.66	$24.16
2020	$750	$1,750	$12.66	$26.27
2021	$750	$1,750	$12.66	$27.32
2022	$750	$1,750	$12.66	$28.37

Natural Gas Price Forecast

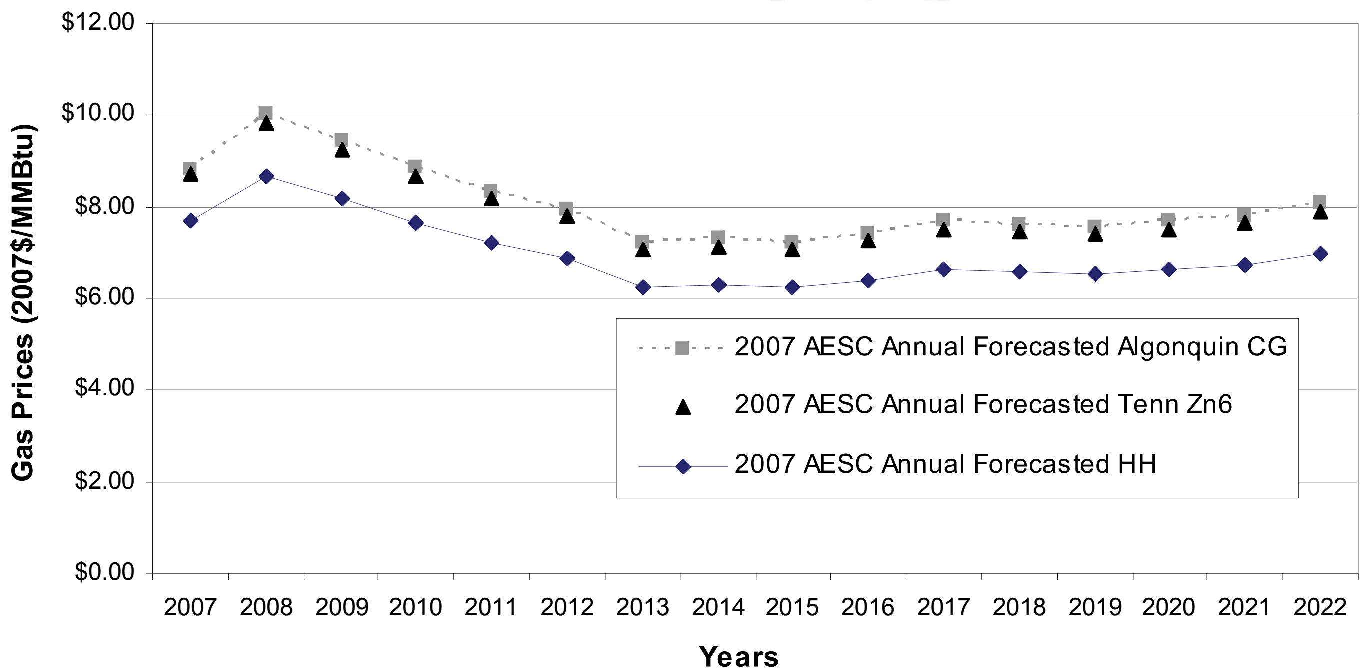
Price of Gas For Electric Generation = Henry Hub + basis differential + lateral charge

- Henry Hub forecast of annual prices
  - 2007 to 2012 – NYMEX (as of May 2)
  - 2013 - 2022 – AEO 2007 reference + Swanson adjustment
- Henry Hub forecast of monthly prices derived from forecast of annual price based on analysis of historical relationship between monthly and annual prices
- Basis Differential - based on analysis of historical relationship between monthly HH prices and monthly prices of spot gas delivered in New England
- Lateral Charge -$0.07/MMBtu (per 2005 AESC)

Avoided Natural Gas Costs – Henry Hub



Avoided Natural Gas Costs – Electric Generation in New England



Wholesale Electric Energy Price Forecast - Benchmarking

Exhibit 5-14. Off-Peak Hub Futures Prices vs. Off-Peak West-Central Massachusetts Forecasted Prices

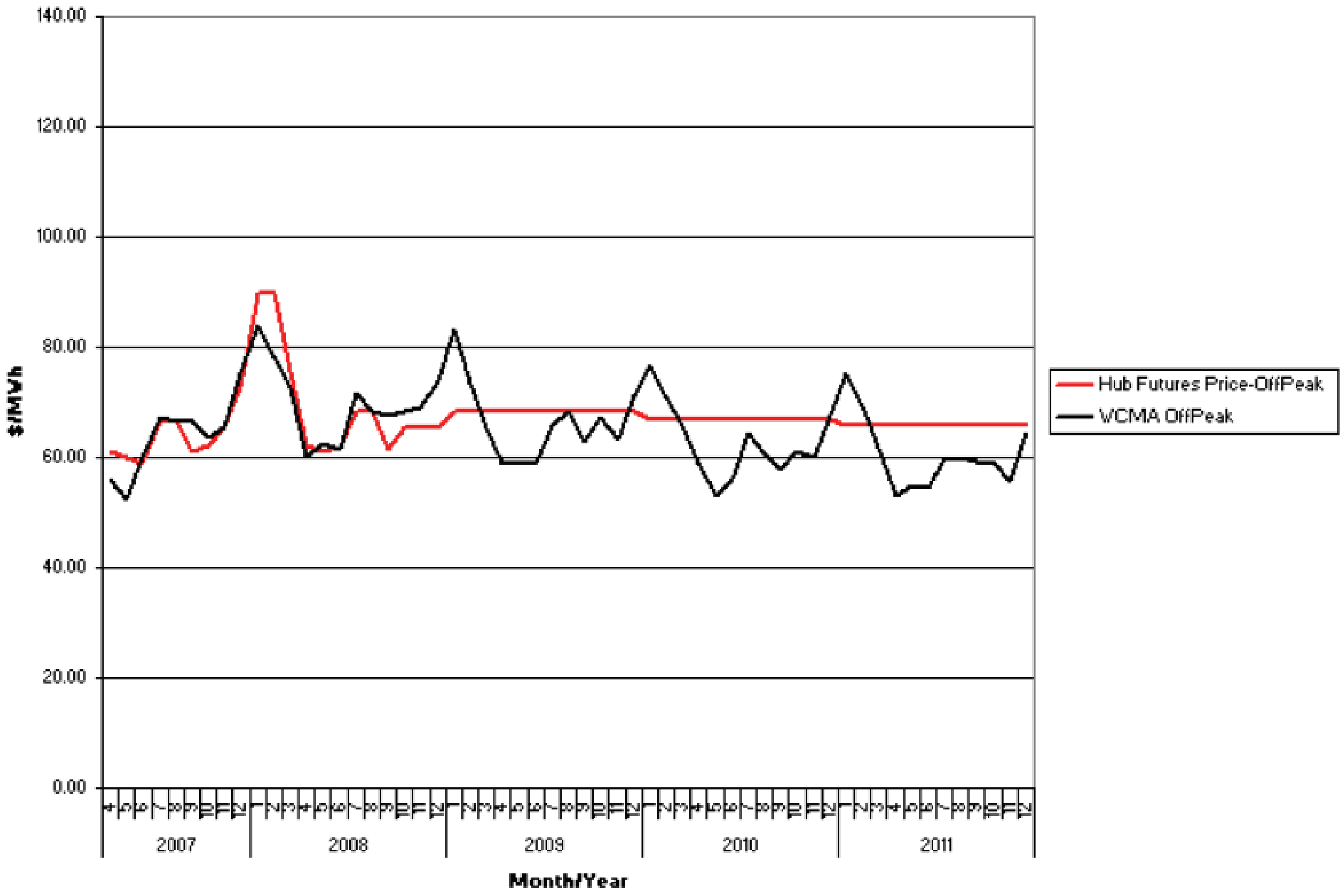
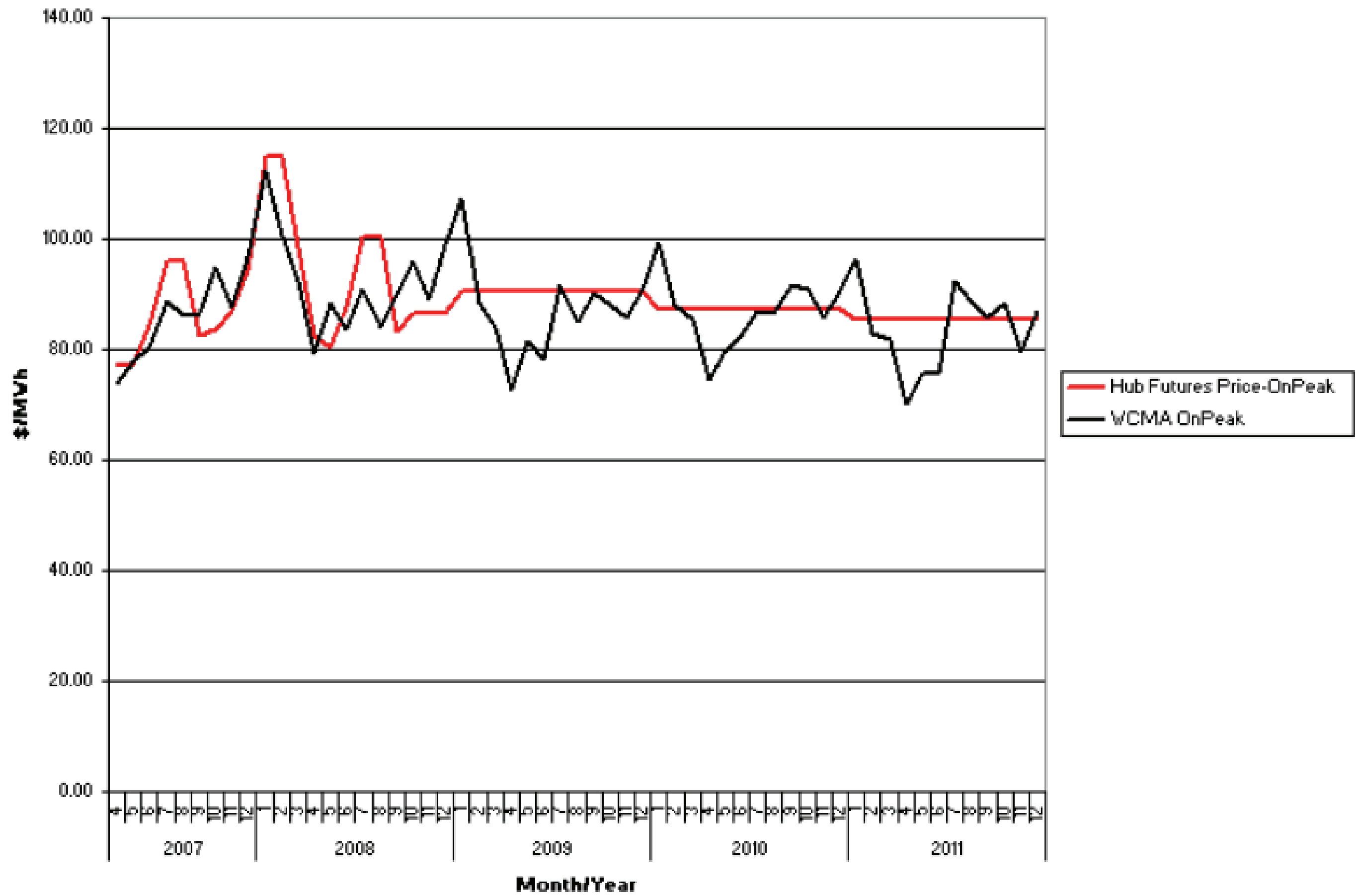
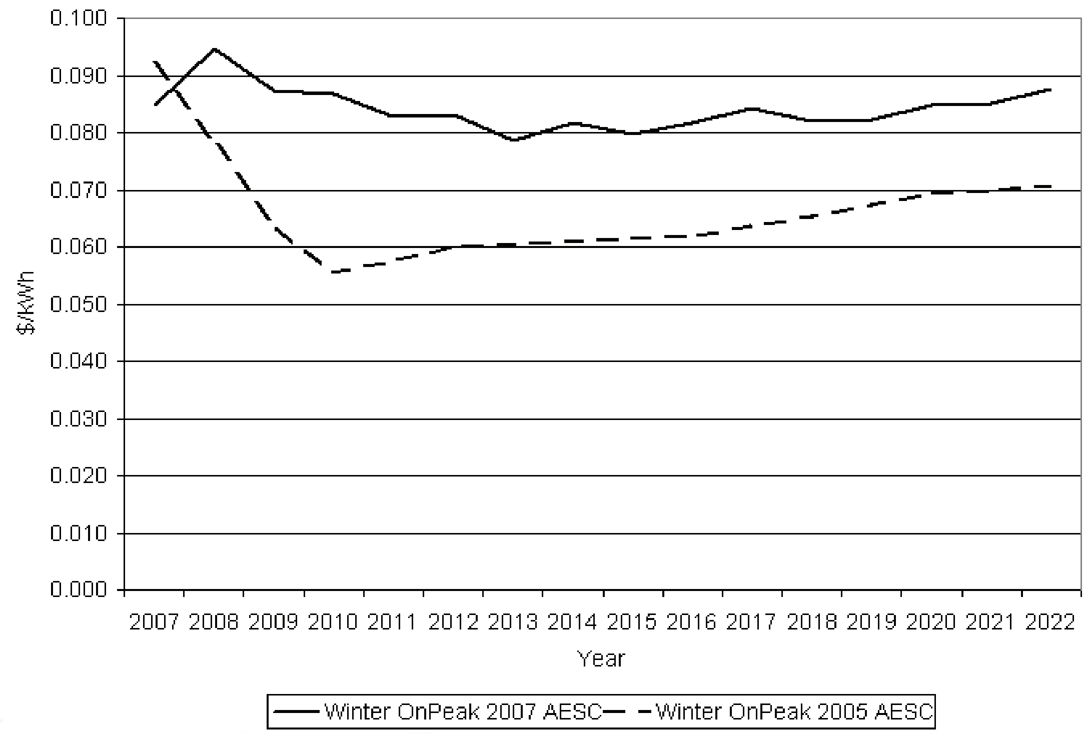


Exhibit 5-15. On-Peak Hub Futures Prices vs. On-Peak West-Central Massachusetts Forecasted Prices



Results – Comparison to 2005 AESC Report

Exhibit 5-14. AESC 2007 vs. AESC 2005 – Winter On-Peak Forecasted Prices



2007 vs. 2005 – Key Drivers

Exhibit ES-3. Illustrative Calculation of Differential in Avoided Energy Costs – 2007 versus 2005

Factor	Differential – 2007 AESC versus 2005 AESC	Impact on marginal electric energy supply cost (cents/kWh) assuming a gas-fired unit with 9,500 btu/kWh heat rate
Natural Gas Prices ($/MMBtu)	1.25	1.2
CO_2 compliance costs $/ton	9.52	0.6
Retail Adder	10%	0.8
Total		2.6

Exhibit 5-18. Contribution of Natural Gas Prices and Carbon Prices to the Total Energy Price

Gas Price	Energy Price Fuel Component	Percent of Total Price	Carbon Price	CO_2 Emission Rate	Energy Price Carbon Component	Percent of Total Price	Variable O&M	Total Energy Price
$/MMBtu	$/MWh	%	$/ton	lbs/MMBtu	$/MWh	%	$/MWh	$/MWh
5.00	50.00	91%	5.00	120	3.00	5%	2.00	55.00
6.00	60.00	85%	15.00	120	9.00	13%	2.00	71.00
7.00	70.00	80%	25.00	120	15.00	17%	2.00	87.00

AVOIDED ELECTRICITY COSTS - RPS

Exhibit 6-1. Avoided RPS Costs Under Alternative Forecasts of REC Prices (Cents/kWh in $2007)

State	$50/MWH		UNH Report	
	2010	2020	2010	2020
CT	0.35	0.35	0.23	0.00
MA	0.25	0.75	0.17	0.00
ME	0.50	0.50	0.10	0.00
NH	0.05	0.57	0.03	0.00
RI	0.13	0.70	0.08	0.00
VT	0.23	0.50	0.15	0.00

AVOIDED ELECTRICITY COSTS - Capacity

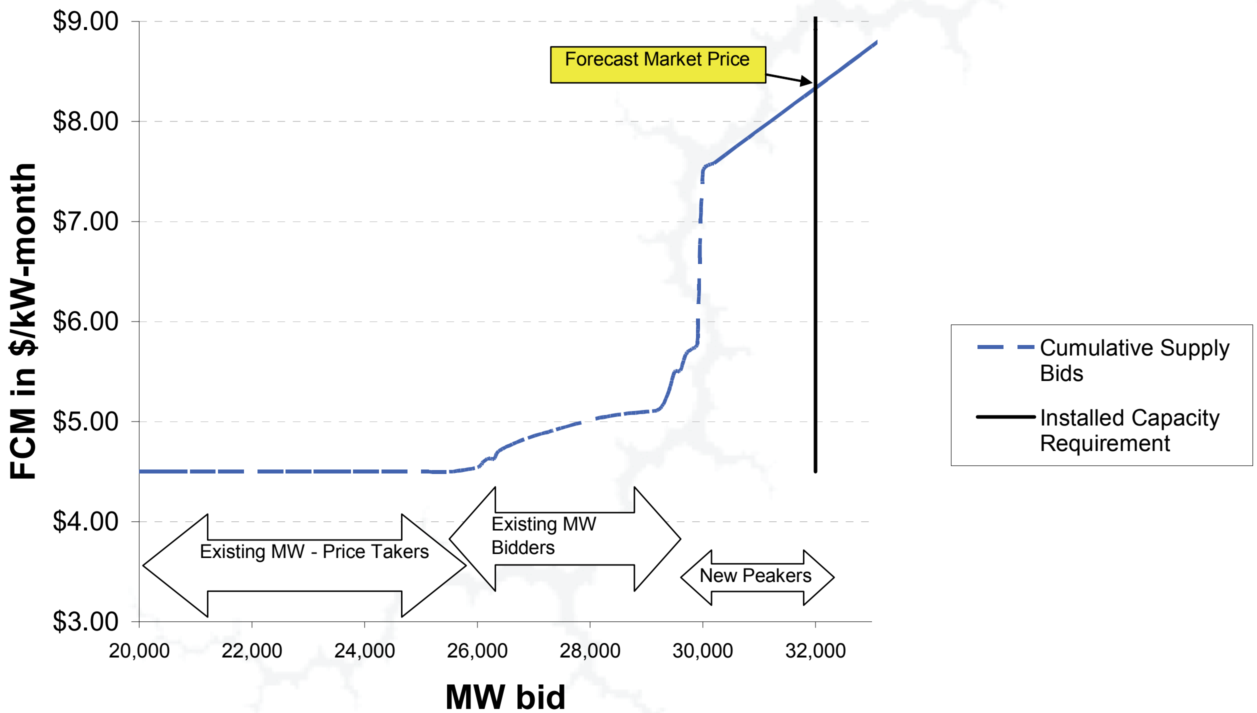
- Transition Period (2006 to May 2010)
  - ICAP values ranging from $36/kw-yr to $48/kw-yr: not avoidable

- Forward Capacity Market (June 2010 onward)
  - Values assume no new DSM
  - Values based on Cost of New Entry (CONE)
  - Marginal new entrant is a gas peaker
    - Levelized fixed cost of $130/kw-yr
    - Less net energy revenues of $30/kw-yr
    - Net fixed cost of $100/kw-yr
    - Plus reserve margin of 14.3%
    - Proposed value $114/kw-yr (2007$)
  - Due to early surge of demand resources bid into FCM, assume 20% reduction in 2010, 10% reduction in 2011

- 2005 AESC Avoided Capacity Costs (2005$, pre-reserve margin)
  - Boston $72/kw-yr
  - Other zones $68/kw-yr

AVOIDED ELECTRICITY COSTS - Capacity

Exhibit 6-3. Illustrative FCM Price with No DSM Bids



AVOIDED ELECTRICITY COSTS – Retail Adder

- Retail adder reflects the difference between prices for electricity supply to retail customers under full-requirements fixed-price contracts and wholesale energy and capacity prices during the corresponding time period.

- Primarily attributable to the costs marketers incur to mitigate their exposure to risk. Risks arise from the potential for costs to exceed revenues due to unexpected levels of consumption due to factors such as unexpected variations in weather, economic activity and and/or customer migration.

- No utility sponsor of this project was able to provide public information on the retail adders implicit in the prices bid by suppliers.

- Confidential data on prices bid by suppliers into standard offer service auctions suggests that a 10% retail adder is realistic.

- This adder was applied to the avoided wholesale energy prices and avoided wholesale capacity prices.

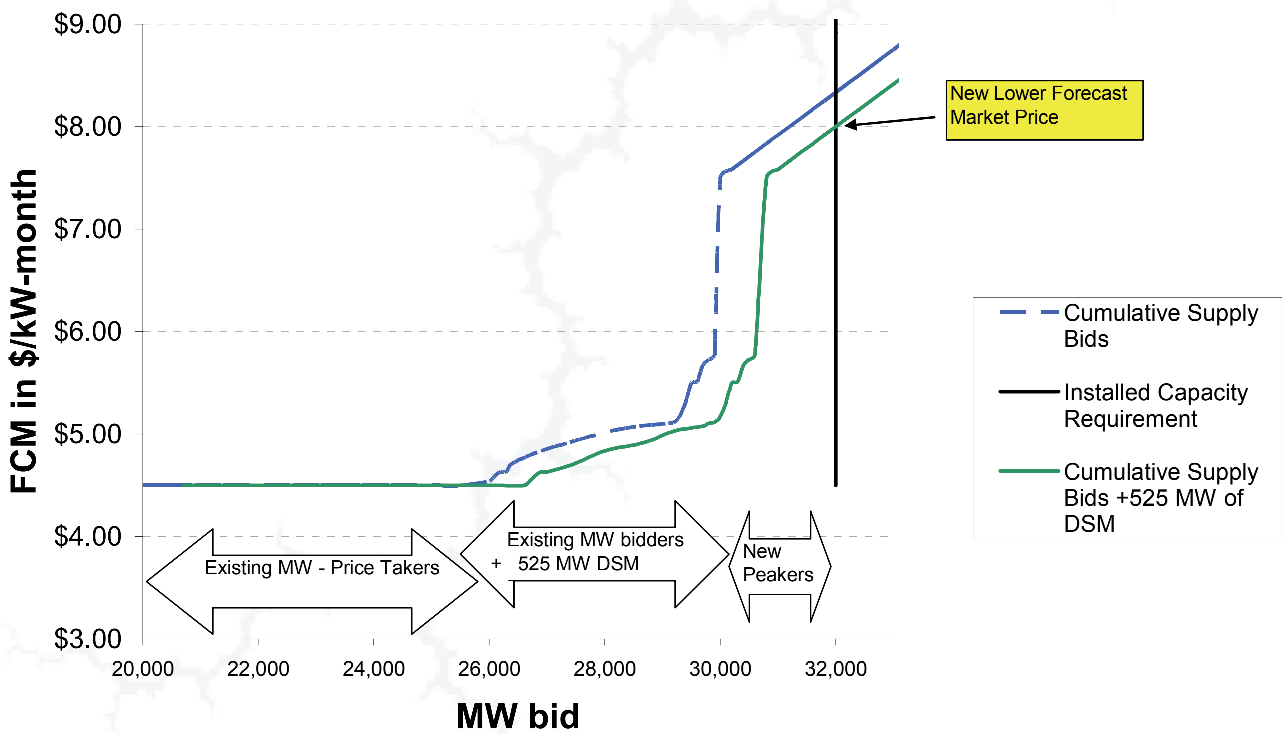
AVOIDED ELECTRICITY COSTS – DRIPE energy

- As load rises, more expensive sources of supply are dispatched and wholesale energy prices rise (all else equal)
- Regressions on historical data show that each additional MW of load in a zone typically increases price
  - from 0.4¢/MWh to 4.5¢/MWh in that zone, depending on the zone and month.
  - from 0.3¢/MWh to 2.0¢/MWh in the rest of ISO-NE pool
- Regressions on historical data show that a 1 MWh load reduction in a zone will reduce energy prices by
  - ~1.1¢/MWh in that zone
  - ~0.6¢/MWh in the rest of the ISO-NE pool.
- These energy price reductions are tiny compared to wholesale energy prices averaging ~$80/MWh
  - **0.014% in the zone**
  - **0.007% in the rest of the ISO-NE pool.**
- **We assume these impacts disappear after 4 years**
- **2005 AESC did not have DRIPE energy**

AVOIDED ELECTRICITY COSTS – DRIPE Capacity

- Expect a number of peakers to submit bids into FCM auction, with typical capacities of 200 MW
- Assume difference between highest bid selected, and next lowest bid, is $1/kW-year.
- Impact of DSM on FCM market price is $0.0000057/kW-year ($1/kw-yr divided by 175 MW of load reduction which at14.3% reserve margin is equivalent to 200 MW of supply)
- Impact is **0.000005%** of a FCM market price of $114/kw-year
- We assume impact dissipates over 5 years
- Estimated capacity DRIPE is about $190/kW-year
- 2005 AESC estimated DRIPE capacity of about $278/kW-year in 2005$ with no upward adjustments for reserve margin

Exhibit 6-12. Illustrative FCM Price with 525 MW of DSM Bids



Environmental Effects – CO_2 Externality Value

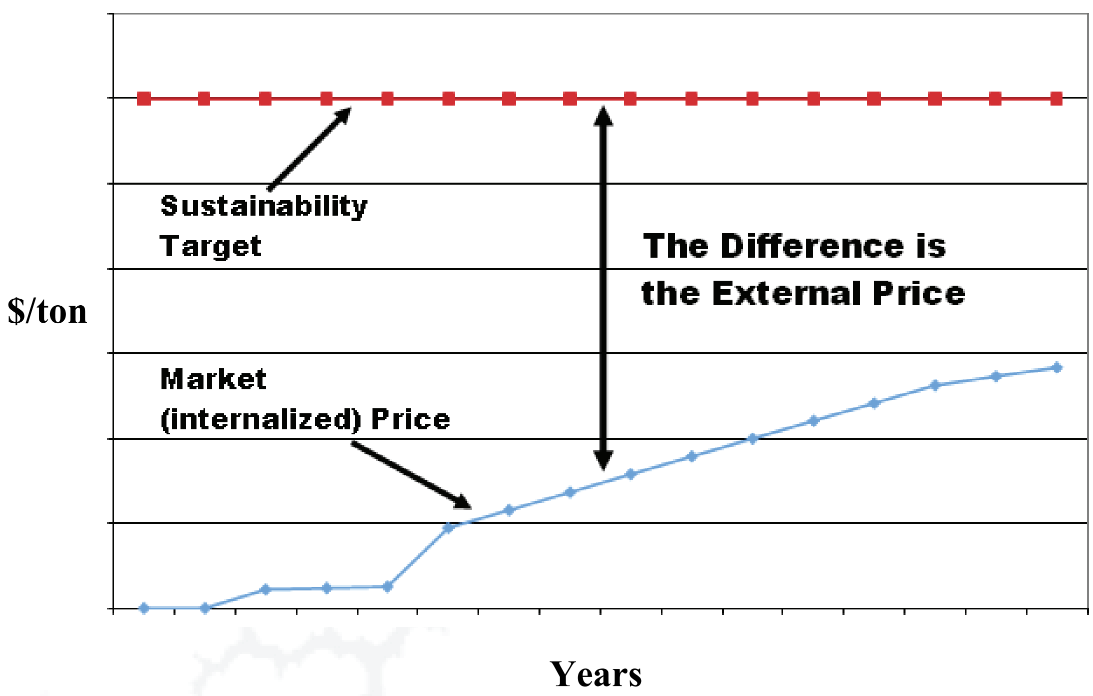
RFP requested review of the reasonableness of the monetized value for avoided emissions the Sponsors were currently using

Synapse proposed to focus on development of values CO_2 because it will be the one major emission associated with avoided electricity costs for which the near-term **internalized** cost reflected in compliance prices most significantly understates the externality value supported by current science.

- avoided electric energy costs are likely to be dominated by natural gas-fired generation, which has minimal SO_2, mercury and particulate emissions and relatively low NO_x emissions. Spending extensive time reviewing the latest literature on externality values for these emissions would not be a good use of time and budget.
- The near-term **internalized** cost of carbon dioxide emissions will be driven by RGGI and proposed federal CO_2 regulations. We expect these will only internalize a portion of the "greenhouse gas externality"

Environmental Effects – CO2 Externality Value

Exhibit 7-13. Determination of the Additional Cost of CO_2 Emissions



Environmental Effects – CO2 Externality Value

Exhibit 7-14. Recommended Externality Values

Year	Sustainability Target Cost ($/ton)	Allowance Price (internalized value) Price ($/ton)	Externality (sustainability target - allowance price) ($/ton)
2007	60	0.00	60.00
2008	60	0.00	60.00
2009	60	2.21	57.79
2010	60	2.37	57.63
2011	60	2.53	57.47
2012	60	9.46	50.54
2013	60	11.56	48.44
2014	60	13.66	46.34
2015	60	15.76	44.24
2016	60	17.86	42.14
2017	60	19.96	40.04
2018	60	22.06	37.94
2019	60	24.16	35.84
2020	60	26.27	33.73
2021	60	27.32	32.68
2022	60	28.37	31.63

Wrap-Up

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