AESC 2018

Presentation of results

March 30, 2018

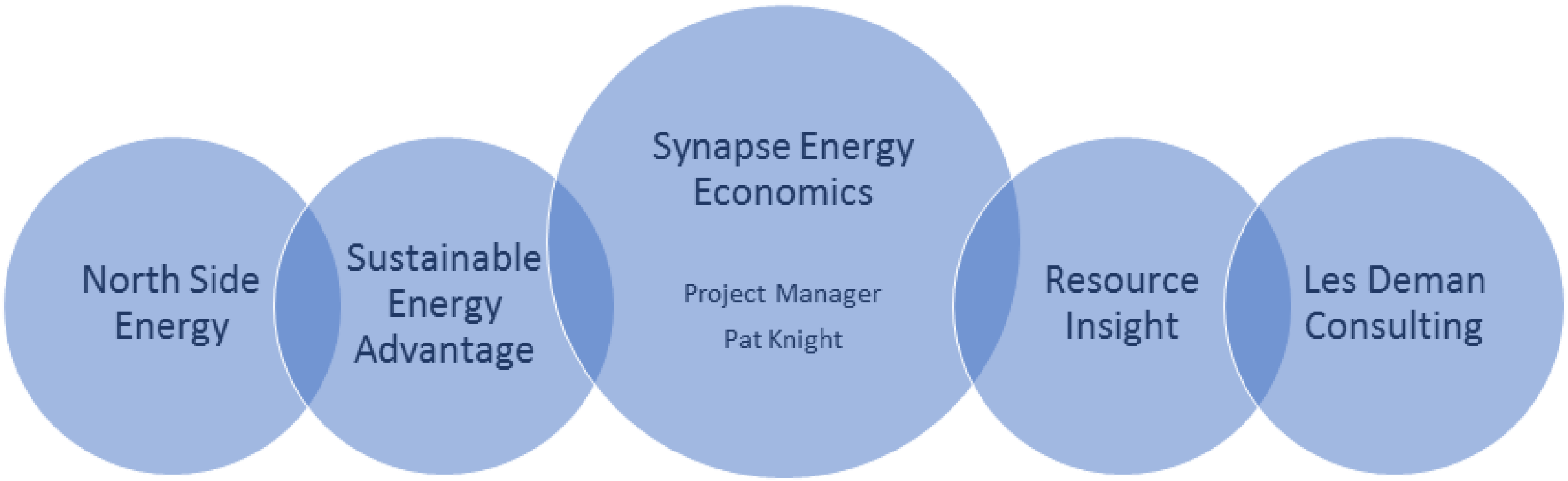
Synapse Energy Economics, Resource Insight, Sustainable Energy Advantage, Northside Energy, Les Deman Consulting

Outline

1. Main findings
2. Chapter results
   a) Natural gas
   b) Fuel oil & other fuels
   c) Common electric assumptions
   d) Avoided capacity
   e) Avoided energy
   f) Avoided cost of compliance with RPS
   g) Non-embedded environmental costs
   h) DRIPE
   i) Avoided T&D costs
   j) Value of improved reliability
   k) Sensitivities
   l) Appendices
   m) User Interface

Project Team and responsibilities

The Synapse Team



North Side Energy
- Avoided natural gas

Sustainable Energy Advantage
- Renewable energy buildouts
- REC/CEC prices
- Avoided cost of RPS and CES compliance

Synapse Energy Economics
- Lead contractor
- Project Management
- Project QC
- Electricity dispatch and capacity-expansion modeling

Resource Insight
- Avoided capacity
- DRIPE
- Assisting on long-term natural gas price forecasting, reliability, oil DRIPE

Les Deman Consulting
- Long-term natural gas price forecast development

Principal Advisor and Internal Quality Control:
Synapse Energy Economics, Principal Associate Max Chang

1. Main findings

- Generally lower avoided costs when comparing with AESC 2015
  - Generally similar costs when compared to AESC 2015 Update
  - Main drivers are lower costs for natural gas & RGGI; new or revised methodologies for capacity, DRIPE
- New chapters on avoided T&D and value of reliability
- Calculated prices and loads at 8760-hour level

ES-Table 1. Illustration of avoided electricity cost components, AESC 2018 versus AESC 2015 (WCMA), summer on-peak

	AESC 2015	AESC 2015	AESC 2018	AESC 2018, relative to AESC 2015	
	2015 cents/kWh	*2018 cents/kWh*	*2018 cents/kWh*	*2018 cents/kWh*	*% Difference*
Avoided Retail Capacity Costs	2.91	3.05	1.72	-1.33	-44%
Avoided Retail Energy Costs	6.29	6.60	4.63	-1.97	-30%
Avoided Renewable Energy Credit	0.96	1.01	0.39	-0.62	-61%
Subtotal: Capacity and Energy	**10.16**	**10.66**	**6.75**	**-3.92**	**-37%**
CO2 non-embedded	**4.88**	**5.13**	**4.36**	**-0.76**	**-15%**
T&D	**-**	**-**	**2.11**	**2.11**	**-**
Value of Reliability	**-**	**-**	**0.01**	**0.01**	**-**
Capacity DRIPE	-	-	0.91	0.91	-
Energy DRIPE	1.18	1.24	1.91	0.67	54%
Subtotal: DRIPE	**1.18**	**1.24**	**2.81**	**1.58**	**128%**
Total	**16.22**	**17.02**	**16.05**	**-0.98**	**-6%**

2a. Natural gas

- AESC 2018 Henry Hub is 19 percent lower than the AESC 2015 base case on a levelized basis; AESC 2018 Henry Hub is 5 percent lower than the AESC 2015 update
- Drivers of wholesale price changes in Henry Hub:
  - Higher gas production
  - Downward adjustment in breakeven drilling and operating costs in the major shale and tight gas producing regions

Summary of 15-year levelized Henry Hub, Algonquin Citygate, and basis differentials

	Units	Henry Hub	Algonquin Citygates	Basis
AESC 2015 (2016–2030)	2018 $/MMBtu	$5.44	$6.23	$0.80
AESC 2015 Update (2017–2031)	2018 $/MMBtu	$4.62	$5.55	$0.93
AESC 2018 (2018–2032)	2018 $/MMBtu	$4.38	$5.39	$1.01
Change from AESC 2015 to AESC 2018	%	-19.4%	-13.6%	-
Change from AESC 2015 Update to AESC 2018	%	-5.2%	-2.9%	-

Notes: All values are in 2018 $/MMBtu. AESC 2015 levelized costs are for 15 years (2016–2030) at a discount rate of 2.43 percent. AESC 2015 Update levelized costs are for 15 years (2017–2031) at a discount rate of 1.43 percent. AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent

2a. Natural gas (cont.)

- Drivers of price change at retail:
  - Avoidable pipeline capacity costs
  - High peak-period prices in the New England market

All Retail End Users, No Avoidable Margin (levelized, 2018 $/MMBtu)

	Units	Southern New England	Northern New England
AESC 2015	2018 $/MMBtu	$6.80	$7.91
AESC 2015 Update	2018 $/MMBtu	$5.96	$7.18
AESC 2018	2018 $/MMBtu	$7.40	$7.18
Change from AESC 2015 to AESC 2018	%	*9%*	*-9%*
Change from AESC 2015 Update to AESC 2018	%	*24%*	*0%*

All Retail End Users, Some Avoidable Margin (levelized, 2018 $/MMBtu)

	Units	Southern New England	Northern New England
AESC 2015	2018 $/MMBtu	$7.71	$8.76
AESC 2015 Update	2018 $/MMBtu	$7.26	$8.00
AESC 2018	2018 $/MMBtu	$8.17	$7.65
Change from AESC 2015 to AESC 2018	%	*6%*	*-13%*
Change from AESC 2015 Update to AESC 2018	%	*12%*	*-4%*

2a. Natural gas (cont.)

- Prices for Henry Hub and the resulting Algonquin Citygates are lower in AESC 2018 than in AESC 2015
- But, we observe a more complex set of trends for the avoided cost of natural gas for retail customers
  - In Southern New England, avoided natural gas costs are lower in AESC 2018 than in AESC 2015 because pipeline capacity costs in AESC 2018 are based on incremental expansion costs, rather than the lower cost of existing capacity as in AESC 2015.
  - In Northern New England, costs are lower relative to Southern New England and AESC 2015 because natural gas delivered through Canada has become a significant marginal resource, as new pipeline capacity from the Marcellus Shale region has reduced the Dawn Hub price basis vs. the Henry Hub. Since the Northern New England market is closer to this source of supply, the avoidable pipeline delivery cost is lower than it is for Southern New England.
  - For Vermont, peak period costs are higher than in AESC 2015 because variable operating costs for the propane-based peaking facilities have been added to the avoided costs, while the avoidable natural gas costs for the remainder of the year are lower than in AESC 2015 because of lower projected natural gas prices at the Dawn Hub.

2b. Fuel oil and other fuels

- We find that avoided levelized costs for residential fuel oil and other fuels are generally higher than was estimated in AESC 2015, while levelized costs for commercial fuel oil is slightly lower than was estimated in AESC 2015.
- The primary source of this difference is a change in data sources from the previous AESC study.

Comparison of avoided costs of retail fuels (15-year levelized, 2018 $/MMBtu)

	Residential						Commercial	
	No. 2 Distillate	Propane	Kerosene	BioFuel	Cord Wood	Wood Pellets	No. 2 Distillate	No. 6 Residual (low sulfur)
AESC 2015 (2016–2030)	$20.15	$19.26	$21.98	$19.61	$7.14	$8.12	$19.63	$17.29
AESC 2015 Update (2017–2031)	$21.22	$19.79	$23.14	$19.61	$7.14	$8.12	$19.87	$17.46
AESC 2018 (2018–2032)	$22.17	$31.11	$19.88	$22.83	$13.40	$21.60	$18.47	$16.26
Change from AESC 2015 to AESC 2018	10.0%	61.5%	-9.6%	16.4%	87.8%	165.9%	-5.9%	-5.9%
Change from AESC 2015 Update to AESC 2018	4.4%	57.2%	-14.1%	16.4%	87.8%	165.9%	-7.0%	-6.9%

2c. Common electric assumptions (i.e., modeling inputs)

- Various pieces of our modeling use the same assumptions for the electric sector
- Demand
  - Assume no EE added in 2018 or later years
  - Annual load trajectory based on ISO New England's 2017 CELT forecast
  - Regional, hourly load shapes based on 2002
- Supply
  - Assume that MA 83C and 83D are in effect
  - Assume that MA DEP policies (CES and CO2 cap) are in effect
  - Assume no change to renewable portfolio standard (RPS) policies, except an extension to CT RPS of 1 percent through 2030
  - Assume units with FCM commitments are built; model builds other CCs/GTs dynamically
- Prices
  - Natural gas: Based on blend of near-term NYMEX futures with long-term prices from AEO 2017
  - RGGI: Based on most recent modeling by RGGI Inc (conducted by ICF)

2d. Avoided capacity costs

- Avoided capacity costs are driven by actual and forecast clearing prices in ISO New England's Forward Capacity Market (FCM).
- Forecasted capacity <u>prices</u> are based on the experience in recent auctions and expected changes in demand, supply, and market rules.

AESC 2018 capacity prices (2018 $ / kW-month)

Commitment Period (June to May)	FCA	AESC 2018	AESC 2015
2018/2019	9	**$9.81**	$13.60
2019/2020	10	**$7.28**	$11.85
2020/2021	11	**$5.35**	$11.89
2021/2022	12	**$4.74**	$12.29
2022/2023	13	$4.84	$12.20
2023/2024	14	$4.94	$11.93
2024/2025	15	$5.22	$12.55
2025/2026	16	$5.65	$12.55
2026/2027	17	$6.13	$12.64
2027/2028	18	$6.60	$12.37
2028/2029	19	$7.07	$13.08
2029/2030	20	$7.54	$13.42
2030/2031	21	$6.60	-
2031/2032	22	$7.07	-
2032/2033	23	$7.54	-
2033/2034	24	$6.60	-
2034/2035	25	$7.07	-
2035/2036	26	$7.54	-
15-year levelized		$6.42	$12.32
Percent Difference		-48%	-

Notes: All prices are in 2018 $ per month. Levelization periods are 2015/2016 to 2029/2030 for AESC 2015 and 2018/2019 to 2032/2033 for AESC 2018. Real discount rate is 2.43 percent for AESC 2015 and 1.34 percent for AESC 2018.
Source: AESC 2015 Exhibit 5-32.

2d. Avoided capacity costs (cont.)

- These prices are applied differently for cleared resources, non-cleared energy efficiency, and non-cleared demand response.
- AESC 2015 assumed that the (at the time) existing capacity surplus would rapidly disappear, bringing the capacity price close to ISO New England’s estimate of net CONE.
- While the capacity surplus did disappear, the subsequent capacity auction (FCA 9) cleared well below the previous estimates of net CONE, and the market price fell substantially in the next few years.
- Since AESC 2015, a large amount of capacity has been added, and ISO New England has reduced its estimate of the cost of new entry (CONE) and shifted the demand curve; these factors have again created substantial surplus capacity.
- Due to changes in the market structure (particularly CASPR), along with expected state-mandated procurement of a large amount of clean energy capacity, retiring major generation is likely to be replaced by renewable resources. Generators will have strong incentives to avoid abrupt retirement, making price spikes (as observed in FCA 8 and 9) less likely.

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2e. Avoided energy costs

- Key drivers of these lower prices include lower overall demand for electricity (even in a future with no incremental energy efficiency), lower Henry Hub natural gas prices, lower RGGI prices, more renewables (caused by changes to the RPS in states like Connecticut and Rhode Island), and the addition of a new transmission line from Canada.
- This decrease is similar to the change in avoided energy costs observed between the 2013 AESC study and the 2015 AESC study

15-year levelized cost comparison for WCMA region (2018 $ / MWh)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2015	$59.38	$65.18	$59.64	$60.54	$47.27
AESC 2015 Update	$49.95	$56.58	$49.02	$48.74	$37.20
AESC 2018	$48.56	$55.67	$51.41	$42.91	$36.72
AESC 2015 Pcnt Diff	-18%	-15%	-14%	-29%	-22%
AESC 2015 Update Pcnt Diff	-3%	-2%	5%	-12%	-1%

Notes: All prices have been converted to 2018 $ per MWh. Levelization periods are 2016–2030 for AESC 2015, 2017–2031 for AESC 2015 Update, and 2018–2032 for AESC 2018. The real discount rate is 2.43 percent for AESC 2015, 1.43 percent for AESC 2015 Update, and 1.34 percent for AESC 2018. Source: AESC 2015 Exhibit 1-5, TCR workbook.

2e. Avoided energy costs (cont.)

- AESC 2018 features a lower ratio of summer peak prices to the annual average than observed in previous AESC studies; this difference can be attributed to:
  - Increased levels of solar generation, which is largely coincident with this period and which have a marginal cost of zero dollars per MWh
  - Difference in month-to-month wholesale gas costs (which are driven by new recent historical data on month-to-month gas costs)
  - Higher levels of zero-marginal cost imports.

2e. Avoided energy costs (cont.)

Avoided retail energy costs, AESC 2018 vs. AESC 2015 (15-year levelized costs, 2018 $ / kWh)

			Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2018	1	CT	$0.065	$0.060	$0.050	$0.044
	2	MA	$0.064	$0.059	$0.050	$0.044
	3	ME	$0.059	$0.055	$0.046	$0.040
	4	NH	$0.065	$0.061	$0.052	$0.045
	5	RI	$0.063	$0.058	$0.049	$0.043
	6	VT	$0.064	$0.059	$0.050	$0.043
AESC 2015	1	CT	$0.082	$0.076	$0.077	$0.062
	2	MA	$0.081	$0.076	$0.077	$0.062
	3	ME	$0.070	$0.064	$0.065	$0.051
	4	NH	$0.080	$0.075	$0.075	$0.061
	5	RI	$0.077	$0.071	$0.071	$0.057
	6	VT	$0.070	$0.065	$0.066	$0.051
Delta	1	CT	-$0.017	-$0.016	-$0.026	-$0.018
	2	MA	-$0.017	-$0.016	-$0.026	-$0.018
	3	ME	-$0.011	-$0.009	-$0.019	-$0.012
	4	NH	-$0.015	-$0.014	-$0.023	-$0.016
	5	RI	-$0.014	-$0.013	-$0.022	-$0.014
	6	VT	-$0.007	-$0.006	-$0.017	-$0.009
Pcnt Diff	1	CT	-21%	-21%	-34%	-29%
	2	MA	-21%	-21%	-34%	-30%
	3	ME	-16%	-14%	-29%	-23%
	4	NH	-18%	-19%	-31%	-26%
	5	RI	-18%	-18%	-31%	-25%
	6	VT	-9%	-9%	-25%	-17%

Notes: These costs are the sum of wholesale energy costs and wholesale renewable energy certificate (REC) costs, increased by a wholesale risk premium of 8 percent (9 percent in AESC 2015), except for Vermont, which uses a wholesale risk premium of 11.1 percent. All costs have been converted to 2018 $ per kWh. Levelization periods are 2016–2030 for AESC 2015 and 2018–2032 for AESC 2018. The real discount rate is 2.43 percent for AESC 2015 and 1.34 percent for AESC 2018. Source: AESC 2015 Exhibit 1-6.

2f. Avoided cost of RPS compliance

- Relative to AESC 2015, AESC 2018 sees generally lower prices for meeting RPS compliance.
- In the near term, a supply boom stimulated mainly by distributed generation policies has surpassed demand, creating a market surplus.
- This surplus is sustained in the long term as substantial supply driven by large-scale renewable procurement policies in Connecticut, Massachusetts, and Rhode Island are expected to become operational without matching growth on the demand side.

Avoided cost of RPS compliance, aggregated by new and existing, by state, 2018$/MWh

	CT	ME	MA	NH	RI	VT
Class 1/New	$2.82	$0.21	$1.72	$1.51	$2.39	$0.53
MA CES	NA	NA	$0.45	NA	NA	NA
All Other Classes	$0.94	$0.31	$1.44	$3.43	$0.03	$1.46
Total	$3.76	$0.51	$3.61	$4.94	$2.42	$1.99

2g. Non-embedded GHG costs

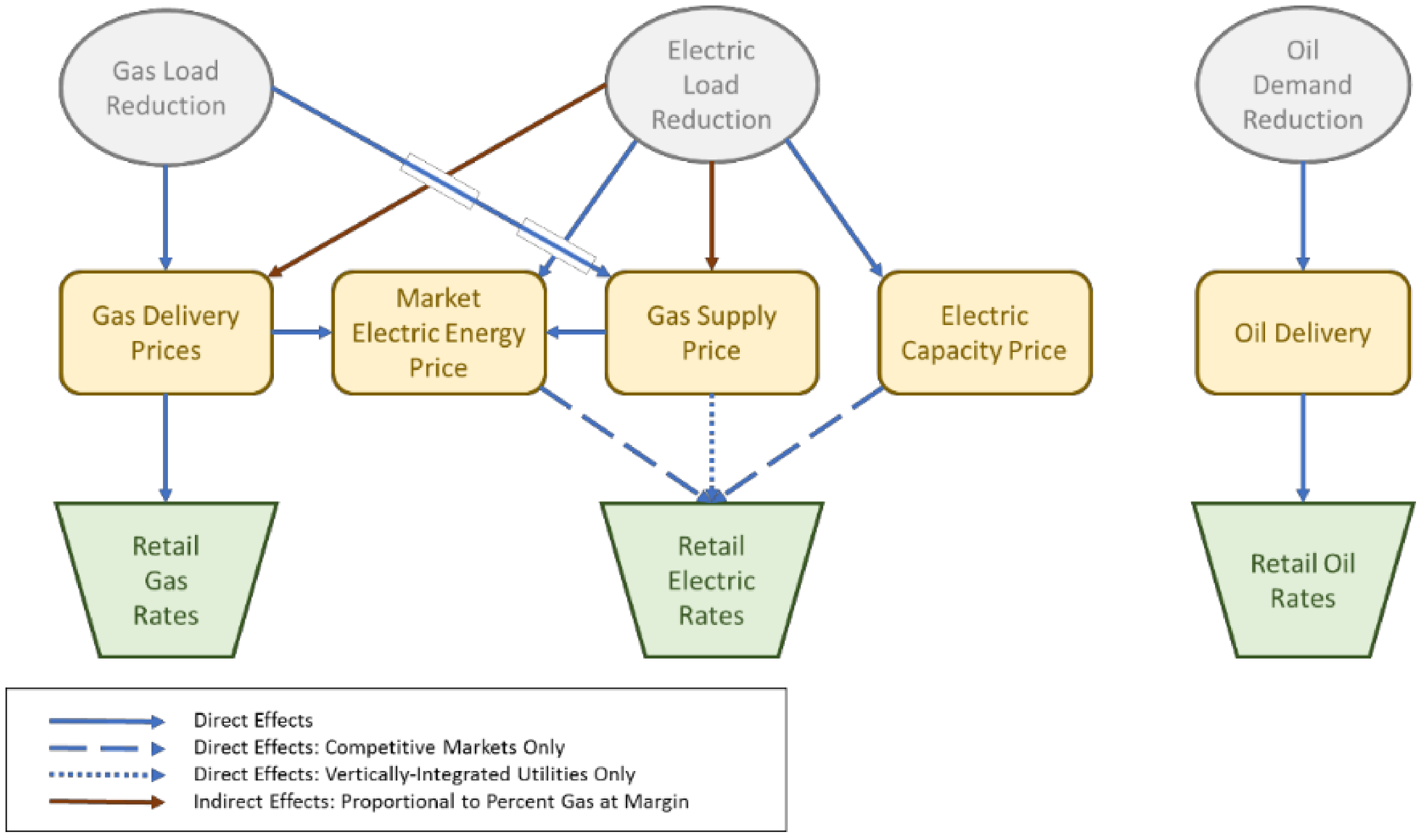
Carbon dioxide

- Two possible approaches: one based on global avoided cost of CO_2, and one based on a New England-centric value
  - Global cost is based on avoided cost of CCS, about $100/short ton
  - New England-centric value based on estimated cost of offshore wind during the study period, about $174/short ton
  - We have performed our initial calculations using the $100/short ton value, but have left it up to the PA's to determine which value should be used in their calculations

Nitrogen oxides

- Based on review of the literature—reasonably large range of values that are typically in the range of $13,000 to $60,000 per ton of N
- Estimated value of $31,000 per ton of N, or $1.58/MWh
- Heavily driven by assumed value of statistical life
- Not applied in Appendix B

2h. DRIPE



Gas Load Reduction
Electric Load Reduction
Oil Demand Reduction
Gas Delivery Prices
Market Electric Energy Price
Gas Supply Price
Electric Capacity Price
Oil Delivery
Retail Gas Rates
Retail Electric Rates
Retail Oil Rates
Direct Effects
Direct Effects: Competitive Markets Only
Direct Effects: Vertically-Integrated Utilities Only
Indirect Effects: Proportional to Percent Gas at Margin

2h. DRIPE (cont.)

- Demand Reduction Induced Price Effect (DRIPE)
- Refers to the reduction in prices in the wholesale markets for capacity and energy, relative to the prices forecast in AESC 2018 which result from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand response programs
- AESC 2018 models DRIPE benefits induced by reduced demand on electricity (energy and capacity), natural gas (supply and transportation), and oil markets
- DRIPE results in AESC 2018 differ from those in AESC 2015 because of differences in analytical approach, assumptions about hedging and decay, new commodity and capacity forecasts, and changes in market conditions.
- We find higher energy DRIPE values, lower natural gas supply DRIPE values, and lower natural gas transportation DRIPE values
- AESC 2018 DRIPE values are zone-specific, rather than state-specific

2i. Avoided T&D costs

- Not addressed in AESC 2015, or previous studies. Avoided PTF cost is a new issue in AESC 2018
- Developed a standardized approach to estimating generic avoidable T&D costs
- Also identified the portion of the pooled transmission facility (PTF) that would be allocated to Local Networks, thus calculating an avoided cost of $94/kW-year. In addition, the various utilities may have some avoidable local transmission cost.
- For non-PTF transmission, and for distribution, we discuss methods for estimating avoided T&D costs in the absence of recent or forecast load growth.
- We also review the methods in use by the utilities and program administrators, and we identify areas in which the methods could be refined to better match the criteria

2j. Value of improved reliability

- New issue in AESC 2018
- Reducing electric loads can improve reliability in several ways, which differ among generation, transmission, and distribution.
- Our analysis addresses the effect of increased reserve margins on generation reliability, the value of unserved energy, the potential and obstacles in estimating the effect of load levels on T&D overloads and outages, and the value of lost load.
- We estimate that the 15-year levelized benefit of reducing of unserved energy through higher generation reserves is $0.65/kW-year for cleared resources and $6.60/kW-year for uncleared load reductions.

2k. Sensitivities

- In addition to the main AESC case, we ran 4 sensitivities:
  - High gas price
  - Low gas price
  - High load (with increased impacts from EVs and heat pumps)
  - With EE (to be used to estimate the costs for non-programmatic EE)
- Main focus of these sensitivities was on impacts to energy price (and capacity price, REC costs, and DRIPE)
- Energy price and DRIPE results:
  - Levelized energy price and DRIPE changes for high/low gas price cases are largely commensurate with changes to natural gas trajectory
  - Levelized energy prices and DRIPE values for high load/with EE cases are largely similar to main case (+/-2 percent), mainly because natural gas trajectory is <u>not</u> changing
- Capacity and RPS
  - Different prices are due to different equilibriums in demand and supply

2I. Appendices

- Appendix A: Usage instructions
- Appendix B: Summary of energy avoided costs
  - Contains text describing how to use these
  - Two pages for each state/zone with annual and levelized values for energy prices, capacity prices, DRIPE, REC costs, non-embedded costs, etc.
  - Also available as an Excel workbook
- Appendix C: Summary of natural gas avoided costs
- Appendix D: Summary of fuel oil and other fuel avoided costs
- Appendix E: Financial parameters
- Appendix F: Description of User Interface
- Appendix G: MA GWSA Compliance costs
- Appendix H: DRIPE derivation
- Appendix I: Matrix of Resources for Value of Reliability

2m. User Interface

- Excel workbook containing hourly load and price data for 2018-2035 for each region
- Dynamically calculates DRIPE values
- Users can view avoided costs according to the traditional AESC costing periods (summer onpeak, etc.), or set up their own costing periods where they focus on peak prices or peak loads

ES-Table 1 notes

1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2018 dollars unless otherwise stated.
2. AESC 2015 values levelized (2016-2030) escalated with a factor of 1.050
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2015 cost (2015 $/kW-year) of $140.10/kW-year
AESC 2018 cost (2018 $/kW-year) of $83.09/kW-year
5. Distribution loss adjustment of 8.0%
6. Reserve margin adjustment of 17.2%
7. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
8. Wholesale risk premium adjustment of 8.0% assumed for AESC 2018. AESC 2015 assumes a value of 9%
9. Avoided wholesale energy cost (2018 $/MWh) of $42.91/MWh
10. AESC 2018 REC price (2018 cents/kWh pre-adjustment) of 0.36 cents/kWh
11. Retail cost = avoided wholesale cost x (1 + risk premium)
12. Assumes T&D cost (2018 $/kW-year) of $94.00/kW-year
13. Assumes reliability value (2018 $/kW-year) of $0.58/kW-year, and a VOLL of $25.00/kWh
14. "Energy DRIPE" is the sum of intrastate electric energy, own-fuel, and electric cross-DRIPE values. In both AESC 2015 and AESC 2018, these DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.
15. AESC 2015 data is from Exhibit 1-2 in AESC 2015. Small differences in values are due to rounding, except for (a) CO_2 non-embedded costs and (b) energy DRIPE which have been adjusted to reflect the AESC 2015 wholesale risk premium.

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