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AGENDA

Electric Utility Commission Resource Planning Working Group Meeting

Date: September 26, 2019

Time: 4:00 pm – 6:00 pm

Location: Town Lake Center, Room 100

Safety Moment (5 Min)

Citizens Communication (15 Min)

Resource Plan 2017 Studies – Q&A (60 Min)

- Distributed Energy Resource Strategy Whitepaper
- Cost and Benefits of Raising Local Solar
- Renewable, Carbon Free and Battery Storage

Resource Planning Working Group Charter (15 Min)

Closing Remarks (10 Min)



2017 Resource Planning Studies Questions & Answers

DISTRIBUTED ENERGY RESOURCE (DER) STRATEGY, NEXT STEPS, AND PRELIMINARY FINDINGS FROM AUSTIN SHINES DER INTEGRATION PROJECT

Questions from Todd Davey

1. Modeling the fielded assets showed the scenario with the SHINES assets increased the per kWh cost versus the baseline case.
2. Page 42 has the following: Note, there are still no O&M costs incorporated into the residential fleet cost estimate. How impactful would the O&M be to the below table?

ADJUSTED Demonstration Data Cost vs. Value Analysis	Kingsbery ESS Grid-scale	Aggregated ESS Commercial	Aggregated ESS + EV Residential
Annual Value Estimate [\$/kWh/yr]	\$137.73	\$149.53	\$119.64
Annual Cost Estimate [\$/kWh/yr]	\$97.88	\$199.90	\$215.83

Cost vs. Value Estimates Using ADJUSTED Austin SHINES Demonstration Data

Initial estimates show that the residential O&M costs for the installed fleet size would be fairly significant and continue to widen the gap between cost and value estimates. This may seem counterintuitive because residential components are purchased off-the-shelf with hardware warranties and minimal requirements, if any, for regular battery or inverter maintenance. However, demonstration phase experience shows that non-trivial personnel time is needed for site visits (to troubleshoot communication/settings issues or to implement warranty transactions), software controls (for the residential aggregator) and data collection. The O&M cost estimate for the installed Aggregated fleet is approximately \$12,000 per year or \$110/kWh/year. Note, however, that the software controls and data collection work would largely remain the same regardless of fleet size, and the installed fleet is rather small. If the fleet were larger, the cost estimate per kWh would decrease. For example, the O&M estimate for a fleet five times larger (550 kWh) is \$19,500 per year or ~\$35/kWh/year. Note, the table referenced in the question shows adjusted value estimates which assumes full value realization for the most valuable control applications. The O&M cost estimates provided in this answer more readily apply to the tables on page 41, which show actual demonstration data. The number at full scale is hard to determine but would be lower than the \$35/kWh/year number, but hard to pin down without competitive bids.

COSTS AND BENEFITS OF RAISING THE LOCAL SOLAR GOALS TO 250 MW BY 2025 AND TO 300 MW BY 2027

Questions from Todd Davey

1. The benefits associated with the Environmental Value Component will be quantified in terms of avoided carbon dioxide and modeled at the current ERCOT Emissions Factor of 982.94 lbs. CO₂/MWh. This value will also be held as a constant in this study, though it will likely trend downward over time.

Figure 9. Value Components of Residential Solar

Value Component	Basis	2018 Value (per kWh)
Energy Value	Avoided cost of fuel, transmission & distribution losses for electric loads using local solar production profile	\$0.029
Plant O&M Value	Avoided cost of natural gas plant operations and maintenance by having local solar at peak periods	\$0.005
Capacity Value	Avoided capital cost of peaking natural gas plant by having local solar at peak periods	\$0.016
Transmission Value	Avoided transmission cost from reduction in peak load by local solar.	\$0.020
Environmental Value	Societal cost of carbon	\$0.015
2018 Assessment:		\$0.085

- a. How is the financial value of CO₂ quantified?

The financial value in the analysis is based on the VoS Environmental component at \$0.015 which is based on the 2016 Societal Cost of Carbon from the EPA.

- b. Why is the downward trend not factored in?

The rate of the “likely” downward trend is not quantifiable, as it would be affected by changes in ERCOT’s generation portfolio which could be impacted by multiple factors.

2. The cost associated with those goals is evaluated at approximately \$32.25MM for 50 MW by 2025 and \$64.5MM for 100MW by 2027.

- a. How will this be passed to the AE customer base?

The Value of Solar (VoS) costs are recovered through the Power Supply Adjustment (PSA). So the environmental component of the VoS costs is passed directly through to the customer. Similarly, costs of incentives are recovered by the Community Benefit Charge (CBC) on the customer’s bill. Meter costs are carried by the utility until the next rate case where they are factored into cost recovery.

- b. Is this capitalized over a term?

Only the meter costs would be carried for a period until we can recover through the following rate case. Performance Based Incentives (PBIs) paid to commercial customers are spread over 10 years, thus smoothing the impact over time.

MODELS FOR UTILITY-MANAGED ROOFTOP SOLAR PROGRAMS

Question from Todd Davey

1. What are the differences in economics and risk between renewable PPAs vs. rooftop solar?

PPAs

- Leverage economies of scale and are significantly cheaper on a \$/kWh and MW basis than rooftop solar (by an average factor of more than 4x).
- PPAs include built in costs for operation and maintenance. They leverage the tax incentives that third parties can use, which ramp down over time – to 10%.
- Generally, these systems are located remotely, with low land prices and good solar potential – but require transmission and distribution to deliver power to the node
- Are easily billed through the Power Supply Adjustment (PSA).
- Distribute the benefits of solar to the entire customer base.

Rooftop Solar Systems

- Being at load, they have the benefits of avoided generation, transmission and distribution cost, as detailed in the Value of Solar methodology. These benefits are passed on to the host customer through the Value of Solar rate.
- Have local economic benefits in terms of jobs and GDP
- The Value of Solar Rate includes an environmental adder of \$.015/kWh recovered through the PSA, which increases costs to all customers.
- Have operational and physical complexity due to billing requirements, additional grid equipment required, multiple interconnections, potential future impacts to power availability, power quality, and safety.

Both

- Include performance and market risks as they may not be producing at times of peak market pricing, though AE is bound to pay for each kWh produced regardless.

RENEWABLE, CARBON FREE & BATTERY STORAGE

Questions from Todd Davey

1. For reference, what have the net load costs for AE been for the previous 5 years?

In short, there is a growing cone of uncertainty which is difficult to quantify. However, Austin Energy is able to provide a range and is confident the result can fall anywhere in the range under various uncertainties. The power supply adjustment cost (PSA) ranges as follows:

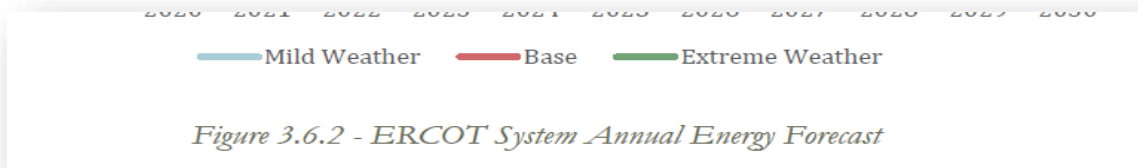
Net Load Cost (\$million)	65%	75%	80%	100%	Carbon_Free
Low (5th Percentile)	\$4,170	\$4,208	\$4,227	\$4,267	\$4,224
High (95th Percentile)	\$6,681	\$6,667	\$6,660	\$6,658	\$6,825

The Net Load cost here refers to the Power Supply Adjustment (PSA). The above table represents the 5th and 95th Power Supply Adjustment (PSA) calculated on a 20-year NPV basis. However, the Table 6.5 & 6.7 show the PSA’s annual average nominal cost.

The Power Supply Adjustment costs (PSA) for the last five years which are available on Austin Energy’s website (Performance Report)

Fiscal Year	PSA (\$)	PSA (\$000)
2014	501,593,156	501,593
2015	443,535,156	443,535
2016	438,230,574	438,231
2017	430,635,460	430,635
2018	437,830,036	437,830

2. What is the definition of the weather scenarios mild, base, extreme?



The weather scenarios represent alternate load forecasts due to weather uncertainty. The Extreme Weather scenario assumes hotter than normal temperatures whereas Mild Weather scenario assumes cooler than normal temperatures in load forecasts. The Base scenario is constructed from expected weather conditions.

3. What is the annual PSA impact when natural gas moves \$1/MMBtu?

The range of the PSA calculated captures sensitivities around gas prices and load. The high and low gas prices are based on fundamentals from Wood Mackenzie's forecasts. Gas prices range anywhere from \$1.28 /MMBTU to \$5.7 /MMBTU. The table below shows the average gas prices for studies under Base, High, and Low Sensitivities.

Base	High	Low
\$ 3.09	\$ 4.36	\$ 1.95

Essentially, when the relative price of gas increases revenues increase for all generation modeled in the portfolio, renewable and conventional. This makes overall costs in the PSA go down.

4. In 3.11 – Are there anticipated additional O&M costs other than the fixed O&M in the chart?

We do not anticipate any additional cost other than the charging cost which is reflected in net revenues.

5. What size battery/storage is assumed in the economic analysis displayed in 4.3.2? Incremental additions of 10 MW/20 MWh (2-hour duration) to meet study goals of 50 MW and 100 MW by 2027. See section 4.3 for battery assumptions and Appendix C for model parameters.

6. If the economics are still unfavorable for battery storage, why are there still plans for installation between 2023-2027? Can we delay until the economics become favorable like the renewable PPAs?

The resource planning process is the opportunity for goal alignment with market and technology forces.

7. What is AE's strategy to address the operational risks associated with large scale renewable energy?

The intermittent nature of energy production from renewable resources introduces various forms of risk. The utility manages this risk in a variety of ways from geographic diversity and contractual terms and conditions to employing active portfolio risk management tools and processes to manage price risk involving production forecasting, market transactions and seasonal, monthly and daily congestion (basis) hedging of renewable resources in the power supply portfolio.

8. Figure 6.1.2 shows system rates. Are these the blended AE rates for all classes?

The system rate is total system net cost divided by total MWh and can be viewed as a blended rate.

9. The carbon-free by 2030 scenario states that it assumes 65% renewable energy in the mix. I am unclear on what is assumed beyond 65% renewable energy, and the use of our nuclear plant. Wouldn't a carbon-free 2030 scenario assume not only that we close the gas plants, but also get the 80 to 85% non-nuclear with renewable contracts? If not, what is assumed in the mix for 2030?

Market participants are not required to balance load and generation in ERCOT. The carbon-free case assumes the portfolio contains no fossil generation. Sand Hill CC and Gas turbines are retired in 2030 and the portfolio has 65 % renewable generation in its portfolio as a percent of load.

Questions from Cyrus Reed

10. In the Carbon-free by 2030 scenario what is the impact to rates of closing sand hill and the other natural gas plants (not including the Decker steam units which are assumed to go away in our present gen plan)?

Relative rate impacts for various scenarios are found in figure 6.1.1

11. In the 100% renewable by 2035 scenario, what is the actual cost of no longer relying on the nuclear power plant? What assumption is made? Would we sell our share of the nuclear plant? Or would we continue to own but just sell it to the market and contract enough renewables to meet 100% of our use through renewable contracts?

Market participants are not required to balance load and generation in ERCOT. We sell ALL of our generation to the market. Both our conventional generation (owned assets) and our contracted assets (renewable resources) generate positive, negative or no revenue depending on a multitude of market factors. The 100% renewable scenario assumes the portfolio has renewable generation that equates to 100% of customer load. The scenario does not exclude the nuclear plant from Austin Energy's power portfolio.

12. The battery storage study seems to indicate that increasing our use of energy storage to 50 or 100 MWs would in most years cost rate payers more than would be offset through ancillary service and other sales. Did the study indicate any sweet spot in terms of MWs owned that would help us earn money or can we assume that whether at 10 MW, 20, 30, 40 all the way to 100 the assumptions used in the model showed a net negative for ratepayers (and the utility?)

The study did perform a so-called "sweet-spot" that addressed the required capital cost for the battery to break-even. The battery is uneconomic, largely due to capital cost assumptions. The study suggests that the required capital cost to break even are between 400 and 500 \$/KW.

13. Would the results of the battery study have been different if Austin Energy subsidized battery storage development, but it was owned by third parties and customers?

Austin Energy utilizes a procurement process and selects resources that provide the lowest cost to our customers. Counterparties participate in this process and are selected based on the value the project brings to the portfolio.

The Economic Impact of the Decker Creek Power Station After De-Commissioning

Question from Todd Davey

1. Conclusion statement - However, these results are predicated on the idea that decommissioning the facility, in and of itself, will not impact the price paid by Austin Energy customers for power in the future. How was this conclusion reached? Why will there not be an economic impact to customers?

Essentially, the economic impact to customers is largely based on wholesale market prices for energy. With annual energy prices averaging lower in recent years, less revenue is expected from these unit's generation. In addition, these units are ill equipped to take advantage of the increased volatility in market prices which manifest themselves in relatively short price intervals.



City of Austin

Austin Energy

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Electric Utility Commission Resource Planning Working Group

Charter Statement

Mission Statement:

The Resource Planning Working Group will provide leadership and guidance on technical and market issues to meet environmental, efficiency and affordability goals established by the Austin City Council.

Working Group is committed to:

- An open and transparent process that represents the diverse interests of the Austin community;
- Developing a plan that is realistic, embraces a leadership position for our city and remains affordable for our customers;
- Recommending a Resource, Generation and Climate Protection Plan to 2030 to City Council; and
- Ensuring the plan can be successful in its implementation by Austin Energy through communication and collaboration with utility staff.

Goals and Rules of Working Group:

- Focus on overarching guiding principles of ~~Affordable~~affordability and clean, renewable energy to ~~achieve~~contribute to the city's goal of achieving net zero carbon by 2050 or sooner.
- Everyone has a voice and are open to other's ideas.
- Committed to moving forward on consensus and resort to voting only when required or desired.
- Citizen's Communication held during the first 15 minutes of the second scheduled meeting each month.
- Agree to utility staff using scenario analysis and risk assessment to screen goal development.
- Resource Plan goals, new and updated, including affordability goals will be developed through a collaborative process between Working Group members and Austin Energy staff.

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- Recommend sunset and/or roll-up of conflicting and/or overlapping resolutions or resolutions that do not conform to updated plan.
- Post meeting agendas in advance to allow preparation by participants.