EUC Resource Planning Working Group Questions

Batch 8

Submitted January 15, 2024

1. In the 11 scenarios previously modeled by Austin Energy, is it correct that the GTs at Decker were assumed to retire by 2027, while the other gas resources would continue to operate until 2035?

   Yes, for modeling purposes the Decker GTs were assumed to be retired by 2027, and SHEC resources were assumed to be retired at the end of 2035.

   a. Does Austin Energy believe that retiring the GTs at Decker by 2027 is feasible, and the existence of the other gas resources at Sand Hill will provide the needed revenues and reliability benefits?

   Decker GTs provide a significant value to Austin Energy in terms of Energy and Ancillary services. They help to mitigate local congestion and provide some of the voltage support that is needed for the Austin Energy service area. It would only be feasible to retire Decker GTs provided they are replaced with similar resources that have the same attributes. From a system reliability and risk standpoint, it is not feasible to retire them if not replaced by similar resources. Moreover, Decker GTs provide Black Start capability which is a crucial component of restoring the grid in the event of a localized or statewide blackout. Before any asset can be retired, it must obtain ERCOT's approval, which seems unlikely given current conditions unless it is replaced by similar resources.

   b. In terms of the resources at Sand Hill, what assumptions is Austin Energy making about how much those resources would be used (what is the expected/modeled capacity factor by year)?

   All the resources are dispatched by economics in the model, which is determined by the heat rate and the fuel cost of the resources provided the constraints are met. This is called Security Constrained Economic Dispatch (SCED). Sand Hill units are no different. The expected capacity factor is an outcome of the model run based on system conditions, so it changes year over year, portfolio over portfolio. In the Base Case (Scenario 1), Sand Hill Combined Cycle has a capacity factor that is ranging from 65% to 85% whereas the GTs range from 8% to 30%.

   c. Does Austin Energy believe that both the Sand Hill GTs and the combined cycle units would be needed for their revenue, reliability and physical hedge against weather extremes through 2035?

Yes, all units at Sand Hill (GTs and the Combined Cycle) are needed to mitigate the affordability and reliability risks that are presented to Austin Energy through and beyond 2035. There is potential in converting these existing units to run on hydrogen or a hydrogen blend, which Austin Energy will continue to explore on its path to Carbon Free by 2035.

d. Which is more valuable to the system - Sand Hill GTs or the combined cycle plant?

Both of them are valuable and critical for meeting local energy supply needs. If these plants were to be retired they would need to be replaced with new dispatchable generation locally to ensure sufficient power supply as well as power quality. In fact, Austin Energy needs more local, dispatchable generation resources to mitigate the risks.

2. Assuming that Decker GT units were to retire on or around 2027, and that Sand Hill units would be retired between 2030 and 2035, what resources could provide the needed voltage support?

   a. Could batteries at Decker and Sandhill be an option for providing that support?

   In theory batteries could be used to provide voltage support, but they are limited duration and thus not always available when needed. Additionally, when charging, batteries add to the load which may increase the need for voltage support. While some batteries can provide voltage support when charging, on a net basis, the result may not be sufficient to meet grid needs. Voltage support from batteries is an area under industry research. While we are optimistic about the promise of battery technologies from a performance perspective, we have concerns about charting a path into the future that makes us wholly reliant upon batteries at scale, which are still largely an unproven commodity at significant scale for a large distribution system. Batteries do not solve the other issues we would look to fully dispatchable generation within the AE load zone to alleviate.

   b. What other solutions beyond reactive power from generation could offer voltage support?

   Many technologies have the ability to provide voltage support to varying degrees. In addition to generation with rotating machinery (e.g. combined-cycle generators, gas turbines, etc.), traditional T&D voltage equipment (e.g. capacitor banks, voltage regulators, static var compensators (SVC), statcom), synchronous condensers, and inverter-based resources (e.g. battery energy storage systems and solar) will continue to be assessed.

c. Could synchronous condensers or capacitor banks be added somewhere on the system?

Likely, yes. Austin Energy is actively assessing this option using assets we already have.

3. Regarding the distributed gas generators that are part of the RaaS program:

a. Are any generators in place and in use yet? If so, how much have they run (for AE use - not backup power)?

None have been installed yet

b. Please provide annual projections for:

Please note that the structure of this program is as follows: a customer serves as the site host, a vendor/asset owner/operator installs and operates the asset on the site according to whatever financial terms they establish with the site host, and Austin Energy pays an annual capacity payment to the vendor for the sole right to use the asset for market dispatch when it is not being used as backup power for the customer. The primary function of these assets is to provide backup power to the customer, and the secondary function is for use in Austin Energy's Demand Response portfolio. The current, Council-approved program terms (price and contract duration) are for the first 25 MW of "Behind the Meter" installed units, but the entire program could approach 250 MW over the next 10 years – assuming there is large-scale uptake from industrial customers. Uptake of this program is heavily dependent on and requires a substantial investment by the customer. Interested customers at this time include grocery stores, water treatment facilities, and the airport.

1. number of units
We are limited in our projections at this time, but, based on customer interest, we think that there will be somewhere between 50-75 MW installed over the next 5 years (125 -185 units assuming ~400kW/unit, unit sizes may vary depending on overall size of install, some vendors may use gas turbines instead of generators).

2. total capacity
See above

3. average hours AE will run units
Initial Terms state that AE may run the units up to 1000 hours per year – but it will likely be less than that – estimating around 300 hours per year, depending on the market conditions

4. emissions information

All participants in the program are required in the vendor requirements to satisfy the following:

a. No water use or connection required (e.g. for emissions reduction system)
b. Meet TCEQ and any federal requirements for Specific constituent (NOx, SOx, PM) levels; must meet TCEQ aggregate site emissions limitations. Vendor must acquire any environmental or air quality permits and meet associated limitations. (Relevant TCEQ section is TCEQ Chapter 106W)
c. Sound: must meet any applicable local noise ordinance requirements for a given project site, and in no case should it exceed <85 dBa at 7 meters from the generator.

Here is a sample emissions chart from the largest vendor in the Texas market:

Figure 1. Generator Emission Factor Comparison

	ERock Rich-Burn		Tier 2 Diesel		Tier 4f Diesel		
Compound	**Engine Zero-Hour Emission Factor (lb/MWe-hr)**	**Emission Factor Source**	**Engine Zero-Hour Emission Factor (lb/MWe-hr)**	**Emission Factor Source**	**Engine Zero-Hour Emission Factor (lb/MWe-hr)**	**Emission Factor Source**	**CARB DG-CERT Engine Emission Factor**
VOC	0.001	ERO Test Data	14.11	NSPS IIII	0.42	NSPS IIII	0.02
NOx	0.0035	ERO Test Data			1.48	NSPS IIII	0.07
CO	1.09	ERO Test Data	7.72	NSPS IIII	7.72	NSPS IIII	0.1
PM/PM10/PM2.5	0.003	ERO Test Data	0.44	NSPS IIII	0.066	NSPS IIII	-
SO2	0.007	AP-42 Table 3.2-3	0.016	AP-42 Table 3.4-1	0.016	AP-42 Table 3.4-1	-
CO2	1,395	ERO Test Data	1,555	AP-42 Table 3.4-1	1,555	AP-42 Table 3.4-1	-

5. any permitting requirements

See above

6. It appears that the cost for in-front-of the meter solar was assumed to be 9.2 cents/kWh for the in-front-of-the-meter local solar. This would imply that AE is going to pay nearly the small-scale VOS rate for those resources. Is that the intention?

   9.2 cents/kWh is an assumption that is used based on the discussions we had on the standard offer for the community solar projects.

c. What was the assumed mix (in MW) of capacity from installations of less than one MW and installations of 1 MW or greater?

   The mix is based on what is requested by the working group. For Austin Energy portfolios, it was assumed to be 50% behind the meter and 50% in front of the meter. In front of the meter solar installations are assumed to be 1 MW or greater.

d. What price per kWh does Austin Energy assume it will pay for energy in those two different capacity groups? If different from the established Value of Solar rate for installations of those sizes, why?

For modeling purposes, Austin Energy assumed behind the meter or customer-sited solar is paid according to the Value of Solar tariff whereas the solar in front of the meter >1 MW costs 9.2 cents/kWh. Refer to the main Q4 above.

4. Form Energy says of their batteries: "Our annual discharge throughput limit will be 1,500-2,000 equivalent hours at full power. In other words, a 100MW battery would be able to discharge 150,000MWh - 200,000MWh in a year." Does this align with how the long duration batteries were modeled for the Working Group's resource portfolios? If not, what was the assumption and why?

   This is close to what we have modeled. Based on our discussions, Form Energy indicated they provide warranty for 13 cycles per year, which equates to 1300 hours at full discharge capacity. This is what we used as a modeling assumption.

5. Please provide the annual cost and rate impact projections for each scenario.

   Cost impacts and affordability are covered in responses to a supplemental information packet comprised of questions received January 10th when AE staff presented the EUC Portfolio results to the EUC Working Group.

Supplemental Questions from Kaiba White email to Amy Everhart Dated 1-17-24

6. Is the Fayette site exempt from congestion charges?

   Congestion is not a charge or line item on a bill. Congestion represents the difference in prices between two locations. For Austin Energy, the revenue from our physical generation resources offsets the cost incurred by our wholesale load. When the price is lower per MWH at the physical generation resource than the price per MWH at our load zone then the net cost to the customer is no longer the production cost of that MWH but rather the production cost plus the basis differential between the two locations. The basis differential or additional cost above the production cost incurred by the customer is referred to as the congestion cost. Austin Energy had ownership in the Fayette Power Project prior to the deregulation of the wholesale market granting us the right to nominate and receive what are referred to as a Pre-assigned Congestion Revenue Rights (PCRRs). PCRRs are a financial instrument that pay Austin Energy the difference between the Fayette Power Project's price (settlement point price) and the Austin Energy load zone price. This allows the financial outcome per MWH to have a similar value as if the asset was located within the Austin Energy load zone but physically it does not provide mitigation to load zone price separation risk. The PCRRs that are nominated are procured for 10% of the auction market clearing price.

Neither the source (generation) nor the sink (the load) in ERCOT is exempt from congestion costs, which are fundamentally incorporated into the Locational Marginal Prices (LMP) at each settlement point in the ERCOT nodal market model. Congestion is also incorporated in the cost to serve load by the LMPs at the settlement points (resource node or load zone). Load Serving Entities (LSEs), like Austin Energy, can procure congestion revenue rights (CRRs) to mitigate the cost of congestion for its customers. With that background, we believe your question is asking if the cost of congestion built into the LMP for Fayette Power Project impacts the cost to serve Austin Energy customers.

Austin Energy has pre-assigned congestion revenue rights (PCRR) for Fayette Power Plant which are allocated at a discounted price (10% of the market clearing price of the auction when it is allocated). The PCRRs help in mitigating any congestion (basis risk) if it exists between FPP and Load Zone AEN.

7. If so, will that benefit continue if Fayette is replaced with a different energy resource?
   No. The PCRRs exist as long as the relationship between the plant and the load exists. This relationship was established prior to Sept 1, 1999. Once the relationship is broken, the benefit is no longer there.

8. If Fayette is exempt from congestion charges, does that result in it being priced the same or similar as the AE load zone?
   Yes, the end result is it will get priced at the AE Load Zone price provided there are no short falls or derates of the allocated MWs.