Responses to Questions/Comments from 11/17/2022 Rate Advisory Committee Meeting and Subsequent Interactions

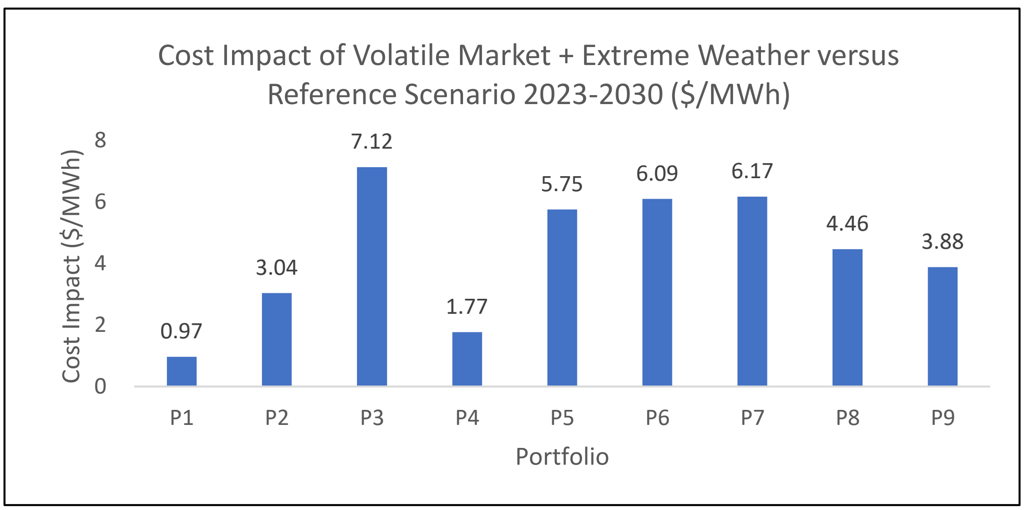
Q&A Packet #3 - Numbering Starts at Question 48 - Version: 12/2/2022

48. Can you provide a sensitivity analysis that combines Volatile Market with Extreme Weather?

- Description of Analysis:

  To approximate the average energy cost impact of an extreme weather year within the Volatile Market (VMA) scenario, the cost impact associated with the extreme weather sensitivity under Reference Case conditions was added to the VMA scenario's average cost projection. Full model simulations were not performed, but given the fact that extreme weather cost impacts are likely to be similar regardless of underlying fundamental market conditions, this approach allows for a reasonable proxy estimate.

	Average Energy Cost by Portfolio and Scenario ($/MWh)							
	Reference Scenario	Carbon Based Economy	Net Zero Economy	Volatile Market	Highest Portfolio	Lowest Portfolio	Reference Scenario & Extreme Weather	Volatile Market & Extreme Weather
	2023 -2030	*2023 -2030*	*2023 -2030*	*2023 – 2030*	*2023 – 2030*	*2023 – 2030*	*2023 – 2030*	*2023 – 2030*
P1	58.07	52.33	56.89	59.85	59.85	52.33	57.30	59.04
P2	60.04	54.57	58.54	62.92	62.92	54.57	60.21	63.08
P3	60.58	55.95	57.71	63.08	63.08	55.95	65.07	67.70
P4	59.16	53.15	57.51	60.60	60.60	53.15	59.48	60.93
P5	60.47	55.09	56.57	61.53	61.53	55.09	65.03	66.22
P6	65.34	61.12	60.85	68.59	68.59	60.85	68.13	71.43
P7	65.96	61.71	61.40	69.23	69.23	61.40	68.81	72.13
P8	60.67	54.82	56.17	62.15	62.15	54.82	63.56	65.13
P9	58.64	53.58	55.94	59.38	59.38	53.58	61.70	62.52



- Conclusion:

  All portfolios tend to have higher costs in the Volatile Market Scenario relative to the Reference Scenario because market prices and new renewable costs are higher. The Volatile Market + Extreme Weather sensitivity is a reasonable proxy estimate of average energy cost in an extreme weather event. When comparing the Volatile Market + Extreme

Weather results to the Reference Scenario results, the P1, P2, and P4 portfolios have less cost impact than the P3 and P5 - P9 portfolios.

P1, P2, and P4 are less susceptible to extreme weather risk, since they have larger amounts of dispatchable (controllable) generation due to the addition of new gas-fired power plants (and the retention of coal in the case of P4) to replace retiring capacity. This would allow CPS Energy to increase generation during periods of high load and extreme market price volatility, reducing customer exposure to market purchase risk during an extreme weather event. In contrast, P3 and P5 – P9 rely primarily on intermittent renewables and short-duration storage to replace retiring capacity, increasing customer exposure to market purchase risk during an extreme weather event.

49. What are the typical land area requirements for solar and wind plants?

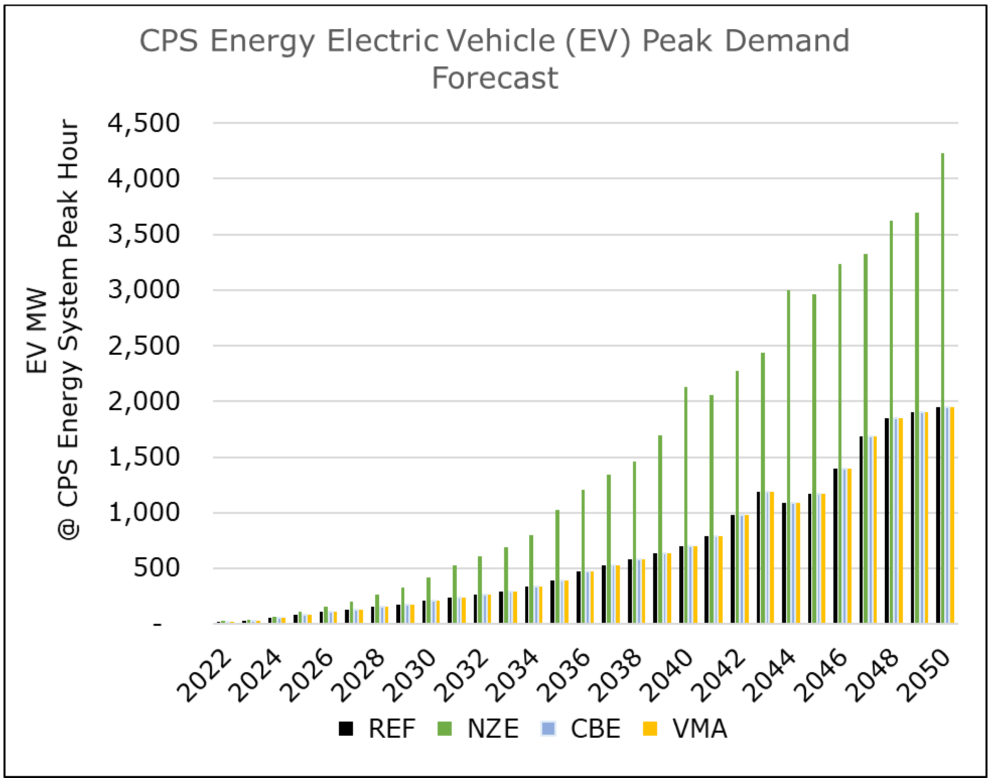
- The U.S. Department of Energy - National Renewable Energy Laboratory (NREL) estimates that a typical utility-scale solar project requires 6.1 acres of land per MW, while a typical utility-scale wind project requires 44.7 acres of land per MW. The table below applies NREL's estimates to total wind and solar capacity additions between 2023 and 2047 in each portfolio to estimate the total land requirements for solar and wind plants across the nine portfolios. For context, there are 172 million acres in Texas.

	2023-2047 Capacity Additions (MW)		
Portfolio	**Wind**	**Solar**	**Total Land Use (Acres)**
Acre/MW	*44.7*	*6.1*	
P1 (Gas)	0	880	5,368
P2 (Blend)	2,300	4,760	131,846
P3 (Ren)	6,600	3,740	317,834
P4 (Blend)	3,100	4,270	164,617
P5 (Ren)	6,700	3,820	322,792
P6 (Ren)	7,700	4,310	370,481
P7 (Ren)	7,900	4,150	378,445
P8 (Ren)	6,300	4,460	308,816
P9 (Ren)	6,600	3,960	319,176

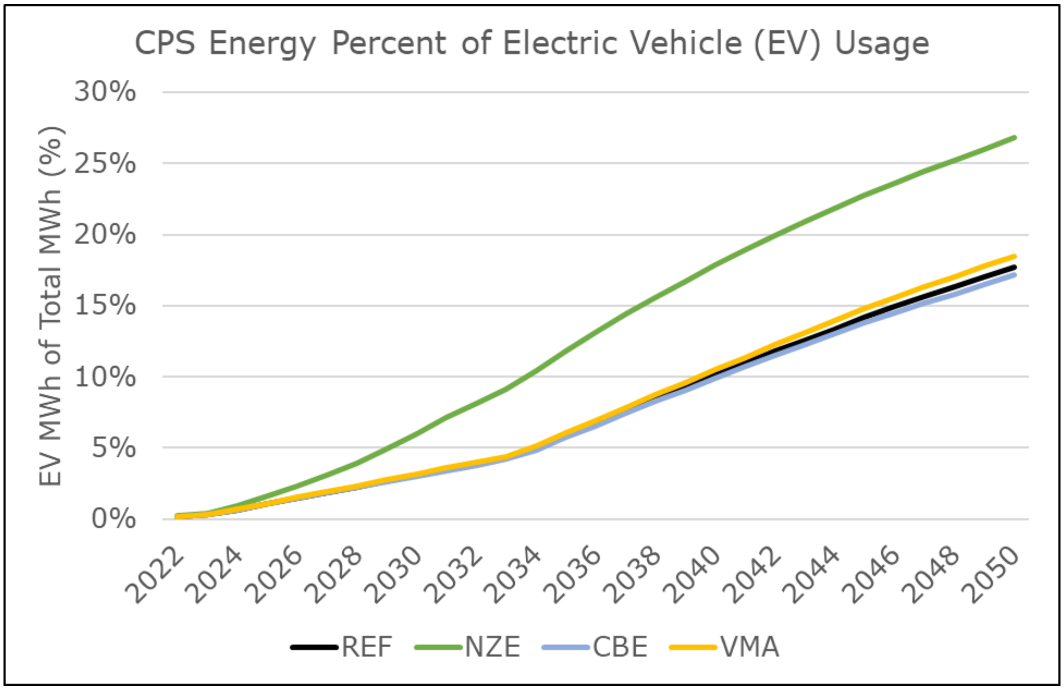
50. Please provide how many electric vehicles (EV) there are currently in the area as both a count and as a percentage of total number of vehicles. Also provide the electric vehicle (EV) peak demand (MW) annual forecast and provide the forecasted electric vehicles usage as a percentage of total usage (MWh).

- CPS Energy leverages Electric Power Research Institute (EPRI) services regarding light duty EV tracking and projections. EPRI provided an evaluation of the San Antonio auto market in December of 2021 on which derivative calculations were based. Based on EPRI data, released in December 2021, for calendar year 2022, there are approximately 9,300 light duty electric vehicles out of 1.4 million total vehicles, constituting 0.7% within the CPS Energy service area.

- CPS Energy's Electric Forecast incorporates energy and peak changes associated with projected growth in electric vehicle adoption for Light Duty Electric Vehicles and Mid-Heavy-Duty Electric Vehicles over time.
- The Reference Scenario contains the "baseline" EV forecast and the Net Zero Carbon Economy Scenario contains a "higher" EV forecast (see the chart below). The Carbon-Based Economy (CBE) and Volatile Market (VMA) Scenarios have EV levels similar to the EV levels of the Reference Scenario. Also see Appendix A for a description of the ERCOT market scenarios.
- The electric vehicle (EV) peak demand (MW) forecast for Light Duty Electric Vehicles and Mid-Heavy-Duty Electric Vehicles is represented below.



- The forecasted electric vehicles usage as a percentage of total usage (MWh) for Light Duty Electric Vehicles and Mid-Heavy-Duty Electric Vehicles is represented below.



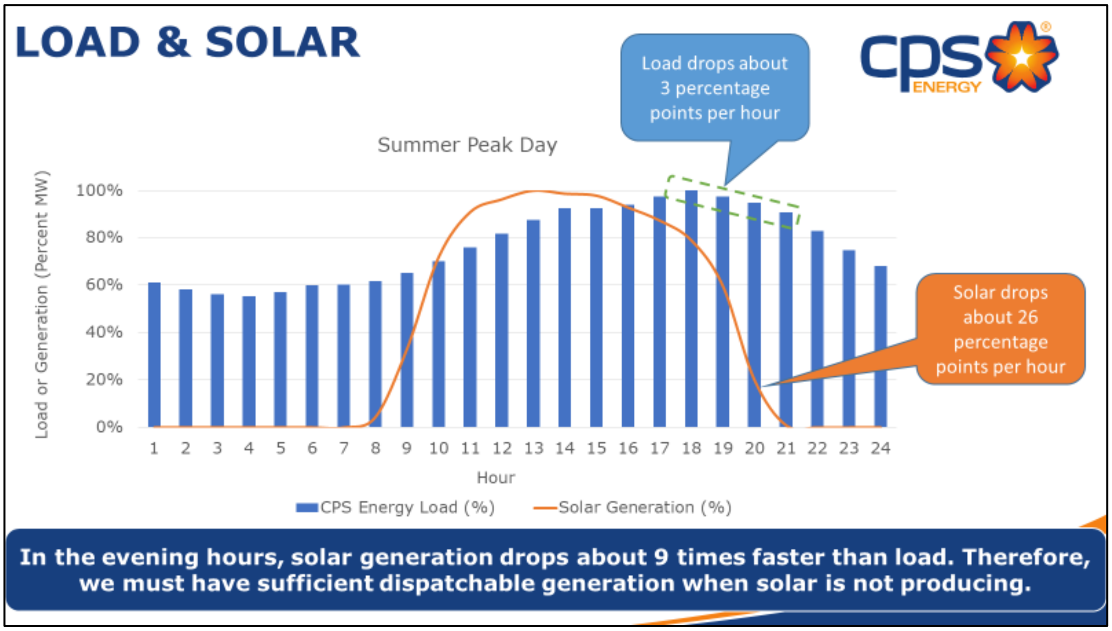
51. Comment from Burns & McDonnell that the Reference Scenario - Sustainable Tomorrow Energy Plan (STEP) appears reasonable, but may be conservative.

    - The details provided by Burns & McDonnell will point out the Reference Scenario for STEP forecast aligns with the program metrics approved in the new STEP program this summer. The forecast assumes we continue with successful programs, but also incorporates a transition to more innovative and equity focused programs. These innovative programs will initially have lower energy and demand savings (in relation to programs they are replacing) as they ramp up. This is typical and similar to our experience in the early years of the original STEP program. Other utilities may also not have as large of a commitment to the underserved communities as we do. Over a quarter of our new STEP budget is focused on equity programs that have large community impacts with lower financial return on savings. In addition, it is important to note the STEP forecast accounts for loss of savings (also known as “decay”) from prior rebated measures (such as solar panels, HVAC units, light bulbs, etc.). reaching the end of their useful life. The decay is overcome through new programs, but by reducing the net total it may result in a forecast that appears conservative.

52. Comment from Burns & McDonnell that capacity value profile for solar may be understating the capacity value of solar.

    - Background on Solar Generation and Customer Load Performance:

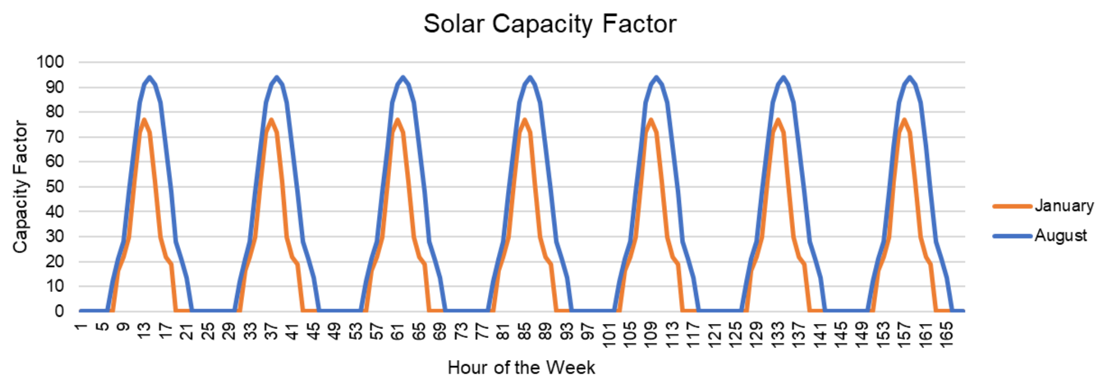
      It is important to establish a foundational understanding of how solar generation and customer load perform on an hourly basis. The chart below shows hourly solar output and hourly customer load performance on a summer peak day. In the evening hours, customer load begins to drop from its peak at a rate of about 3 percentage points per hour, while solar generation also begins to drop from its peak output at a rate of about 26 percentage points per hour. The result is that solar generation drops about 9 times faster than customer load, which is why we must have sufficient dispatchable generation to serve our customer load when solar is not producing. In general, the amount of dispatchable generation needed to serve our customer load, when solar is not producing, increases as solar becomes a larger portion of the generation portfolio.



- Capacity Value of Solar

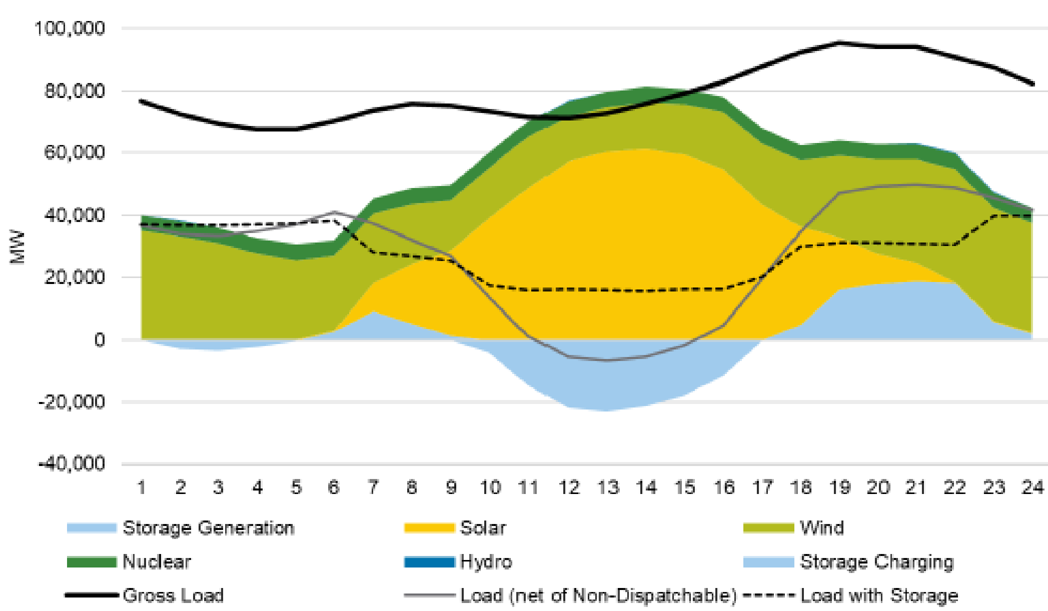
  Capacity factor and capacity value (or capacity accreditation) are two different concepts that measure the contribution of power plants (in this case solar plants) towards providing various power market services.

  The *capacity factor* measures how much electricity is produced by the solar power plant relative to its maximum output during a period of time (e.g. over the course of a year, a month, or an hour). It is measured by dividing the total electricity produced during the period of time by the amount of electricity the plant would have produced if it operated at its full capacity potential during the period of time. The capacity factor of solar varies from hour to hour and across days, months, and seasons. For example, the figure below shows the model's assumed capacity factors for a week in January and a week in August. Hour 1 corresponds to the hour ending 1 AM on Monday while hour 168 corresponds to the hour ending midnight on Sunday. As shown, solar irradiation is higher in the summer and summer days are longer, so on average, the capacity factor in August will be higher than the capacity factor in January.



The *capacity value* measures the fraction of the installed capacity that can be relied upon during the hour of net peak demand. Net peak demand is defined as peak demand less generation from "non-dispatchable" sources including solar and wind. The *capacity value* is used when calculating reserve margin, which aims to measure the buffer between the generating capacity expected to be available during the time of net peak demand and the net peak demand. Currently, the net peak load hour in ERCOT occurs at hour ending 5 PM in August. ERCOT currently estimates that a solar plant can be expected to have 81% *capacity factor* during the hour ending 5 pm in August. Therefore, the *capacity value* of solar is currently 81%. CRA assumes 81% capacity value for solar at the start of the modeling time horizon across the broader ERCOT market.

However, over time, the ERCOT-wide net peak is expected to shift towards hour ending 10 pm as solar capacity increases. In other words, while the gross peak for the system will still occur around 5 or 6 pm, the peak net of non-dispatchable resources will shift later in the day. This later net peak is what system planners focus on, because sufficient capacity needs to be available for all hours of the day. The *capacity factor* of solar trends towards zero after hour ending 10 pm, meaning that as the system's net peak moves later



in the day, the *capacity value* of solar will decline. The figure above shows CRA's projected ERCOT hourly load in August 2045 along with wind, solar, nuclear (resource types that are generally non-dispatchable), and storage energy contributions. The figure shows gross load in the solid black line and net load in the solid grey line. The gross load in 2045 (black line) is expected to peak at around hour ending 6 pm. However, high levels of wind and solar generation push the net load in 2045 (grey line) to peak at around hours ending 9 - 10 pm, when solar generation is low (yellow area). This example provides an illustration of the calculations that occur within CRA's ERCOT market model (Aurora), which looks at the top net peak hours across the year and calculates a contribution to peak for intermittent resources like solar. Overall, the expected *capacity factor* for solar during hour ending 9 pm in August is 13.4% and during hour ending 10 pm is zero. Thus, CRA assumes that the ERCOT capacity value for solar will decline from 81% in 2023 to 12% by 2048.

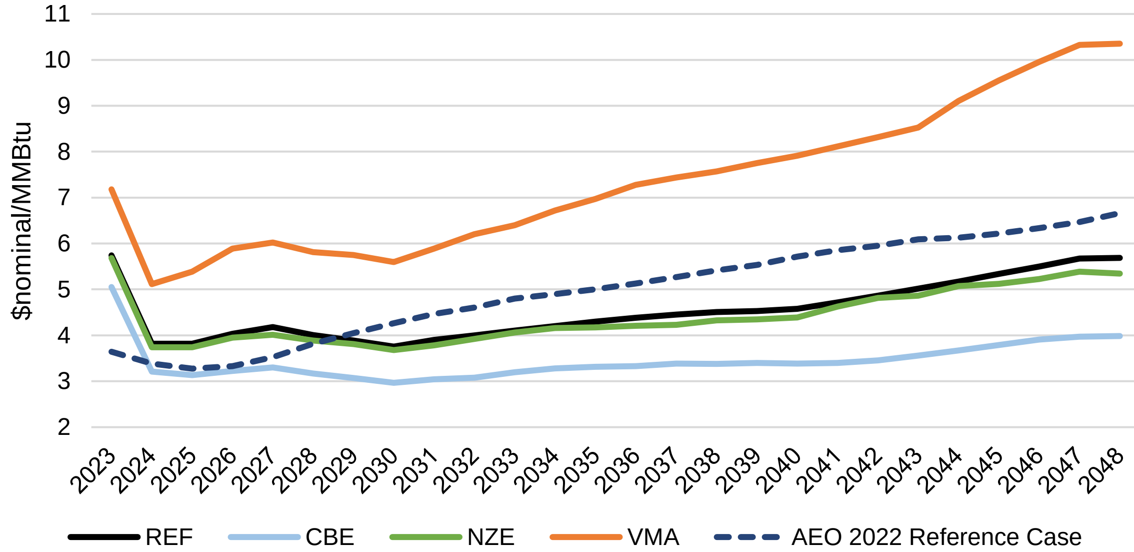
Such declines in solar capacity value are not unprecedented across the industry, and many ISOs across the country are studying the issue and projecting the possibility for solar credits to decline below 20% over the long-term. For example, although a very different market than ERCOT, California's official planning documents *already* project solar capacity value to be only ~14% *next year* (2023). This is due to the recent influx of solar in the region, a phenomenon that is expected to occur in ERCOT over the long run.

Note that CPS Energy has a different load profile and a different supply-demand balance than ERCOT as a whole, so for the portfolio analysis, CRA collaborated with CPS Energy to derive the capacity value for solar specific to CPS Energy's portfolio. CPS Energy's net peak is currently at hour ending 7 pm, and the FlexPower Bundle will add 880 MW of solar capacity over the next several years, which is expected to shift CPS Energy's net peak to hour ending 9 pm from 2025 onwards. Accordingly, the capacity value for solar in CPS Energy's portfolio is modeled to decline faster than the capacity value for ERCOT solar, i.e. declining below 5% in 2025, and trending towards near 0% by 2048. See Appendix B for reserve margin slides from the Oct 2022 RAC meeting.

53. Comment from Burns & McDonnell that the <u>Reference</u> (REF) Scenario - Gas Price forecast may be somewhat low.

    - Scenarios are used as a tool to evaluate the risk profiles of each portfolio. They are meant to cover a broad but possible range of future outcomes. The <u>Reference</u> (REF) Scenario contains "<u>baseline</u>" gas price projections, which are aligned with current trends. The <u>Carbon-Based Economy</u> (CBE) Scenario contains the assumption that a plausible <u>sustained low</u> gas price environment will prevail, the <u>Net Zero Carbon Economy</u> (NZE) Scenario contains the assumption that "moderately <u>lower</u>" gas prices will prevail, and the <u>Volatile Market</u> (VMA) Scenario contains the assumption that "<u>high</u>" gas prices will prevail. We believe that the four scenarios provide a reasonable range of gas prices to test the portfolios against.

    - CPS Energy uses data from multiple, reputable third-party providers when developing its Reference Case natural gas price forecast over the long-term. While we acknowledge that the CPS Energy Reference case is slightly lower than the AEO 2022 Reference case over the long-term, different forecasters across the industry have different fundamental views that may be slightly higher or lower than the AEO. The range of outcomes that has been developed across the four scenarios covers the full range published in the AEO (as noted by Burns and McDonnell in the RAC meeting), and the other public and private forecasts that CRA and CPS Energy have access to are all well within this range. See the charts below showing the range of gas prices in nominal dollars. Also see Appendix A for a description of the ERCOT Market Scenarios.



54. Comment from Burns & McDonnell that the use of stochastically-developed pricing and cost inputs to generate a range of possible outcomes was not performed.

- We agree with Burns & McDonnell that using stochastically-developed pricing and cost inputs is one means of providing rich insights into how each of the nine portfolios might perform over various combinations of future outcomes. We had considered conducting a stochastic analysis as part of the generation planning process, but based on RAC member focus and feedback, CPS Energy and CRA determined that the four scenarios plus the extreme weather sensitivity would sufficiently cover the range of outcomes that would be evaluated in any stochastic analysis.
- Although they are not designed to cover short-term market shocks, the four scenarios represent a wider sustained range of potential future outcomes for commodity prices, carbon prices, demand, and technology prices than what would be picked up in a stochastic assessment. Furthermore, the scenario-based approach provides RAC members with a narrative understanding of how each portfolio might perform over different future states of the world and allows the RAC members to make decisions based on their assessment of the likelihood that each state of the world might materialize.
- Stochastic analysis is most-effectively deployed to assess short-term, random shocks to the system, and the extreme weather sensitivity was specifically designed to evaluate a tail event from a stochastic distribution. The focus on one event was in direct response to significant interest from RAC members regarding how the portfolio options would perform under such conditions. The sensitivity tests portfolio performance under an extreme set of correlated uncertainties, including very high gas and ERCOT power market prices, very high demand, very low renewable output, and increased outages for gas plants. This sensitivity represents a low probability but high impact outcome that a

stochastic analysis is designed to capture. It also allows the scorecard to track a very specific event as opposed to just a percentile point on a distribution.

55. Is the end-of-life disposal cost or battery replacement cost for storage batteries accounted for in the cost estimates?

    - When building up ongoing capital and fixed operations & maintenance costs associated with energy storage purchase power agreement (PPA) costs, CRA included the cost of removing and replacing degraded battery cells to maintain the same level of storage capacity during the project's full life. CRA's cost estimates include fixed operations and maintenance costs associated with preventative equipment maintenance and performance maintenance. They also include augmentation costs associated with battery cell replacements to compensate for degradation in order to maintain the battery capacity over time. Augmentation costs include an expected overhaul of battery modules after approximately 15 years of life, since PPA time horizons were assumed to be longer. Note that no additional "disposal" cost at end-of-life was assumed.

56. Why was expensive geothermal selected in 2030 for P6/P7?

    - CRA used the Aurora portfolio optimization tool to select a combination of resources that meet key planning constraints at the lowest cost. The key constraints are outlined in more detail in the response to question #32 in the last Q&A packet, but notably they include meeting reserve margin targets and meeting the technology availability and build limits. These constraints were applied across all portfolios.
    - In P6 and P7, two of CPS Energy's existing natural gas combined cycle plants are retired in March 2030. This is in addition to the retirements of both Spruce units, Braunig 1 – 3, and the Sommers units. The retirements of the two combined cycle plants alone (Arthur Von Rosenberg and Rio Nogales) represent approximately 1,500 MW of generating capacity that has to be replaced in order to meet CPS Energy demand and maintain the reserve margin.
    - Only renewable technologies are allowed in P6 and P7, and the capacity value of solar in CPS Energy's portfolio is expected to decline significantly by 2030 (see Question # 52 in this document). Therefore, only wind, hydrogen, and storage can be used to maintain the portfolio reserve margin until other new technologies are made available. Given the large volume of capacity retirements in P6 and P7, the model reached the maximum build limits on wind (800 MW per year), hydrogen (240 MW per year) and storage (1,000 MW per year). Therefore, in 2030 the model selected geothermal (275 MW) as the next least cost option in order to have sufficient new capacity and firm energy to replace the retired capacity and energy that left the portfolio. Note that the build limits are based on CRA's review of recent and expected trends in capacity additions in ERCOT and are influenced by the ability of developers and supply chains to deliver new capacity. See Appendix C for slides on technology availability and build limits from the October 2022 RAC meeting.
    - It is also important to recognize that the costs of P6 and P7 are still significantly higher than the other portfolios <u>*before*</u> the addition of the geothermal resources, so although Slide 30 from the November RAC meeting called out geothermal as an example of high-cost capacity, the new wind, solar, and storage required to replace all the retiring thermal capacity drives costs higher for P6 and P7 prior to 2030 as well. This is shown in the annual cost data detail that was shared with RAC members in the Data Packet provided prior to the November RAC meeting.

57. Explain what mitigation measures may be possible for P2 to comply with the 2040 CAAP carbon reduction target.

- Established technologies will be used in the 2023 to 2030 timeframe to replace aging generation. Emerging technologies that prove cost-effective and reliable will be installed beyond 2030. There is ample time for CPS Energy to pivot and include new technologies in the generation plan for capacity additions in the 2030s and beyond.
- The main source of long-term carbon emissions in Portfolio P2 is the natural gas-fired power plants. There are currently several technologies in development that could become widely commercially available in the 2030 to 2040 timeframe and beyond, and reduce carbon emissions from gas-fired power plants, including:
    i. Use of green hydrogen as a means to store energy;
    ii. Use stored green hydrogen and renewable natural gas to fuel gas-fired power plants;
    iii. Construct enhanced geothermal energy plants;
    iv. Continue adding wind and solar in conjunction with high capacity, long-duration storage technologies;
    v. Reduce the output of fossil resources through modified dispatch;
    vi. Retrofit existing natural gas generation units with reliable, cost-effective carbon capture and storage technologies; and
    vii. Expanded use of carbon offsets.

APPENDIX:

A. ERCOT MARKET SCENARIOS

B. RESERVE MARGIN ASSUMPTIONS

C. TECHNOLOGY AVAILABILITY & BUILD LIMITS

APPENDIX A:

ERCOT MARKET SCENARIOS

ERCOT Market Scenarios

CRA developed 4 ERCOT Market scenarios, which are designed to reflect diverse but possible future states of the world. Each scenario comprises a combination of five input variables whose levels vary across the scenarios, as shown below.

ERCOT Scenario	Natural Gas Prices	Carbon Policies	Technology Costs	Demand Growth	ERCOT Market Design Change
Reference Scenario (REF)	Baseline	Baseline carbon price	Baseline	Baseline	Confirmed changes only
Carbon-Based Economy (CBE)	Lowest due to production increases	No carbon price	Baseline	High demand driven by low fuel and carbon prices	Confirmed changes only
Net Zero Carbon Economy (NZE)	Low due to electrification drive	High carbon price	Faster decline + Inflation Reduction Act Tax Credits*	Highest demand driven by electrification	Capacity market launched & seasonal reserve margins
Volatile Market (VMA)	High	No carbon price to alleviate inflation pressure	Slower decline + Inflation Reduction Act Tax Credits*	Low demand due to high natural gas prices	Confirmed changes only

*Note that all CPS Energy portfolio analysis incorporates IRA tax credit provisions.

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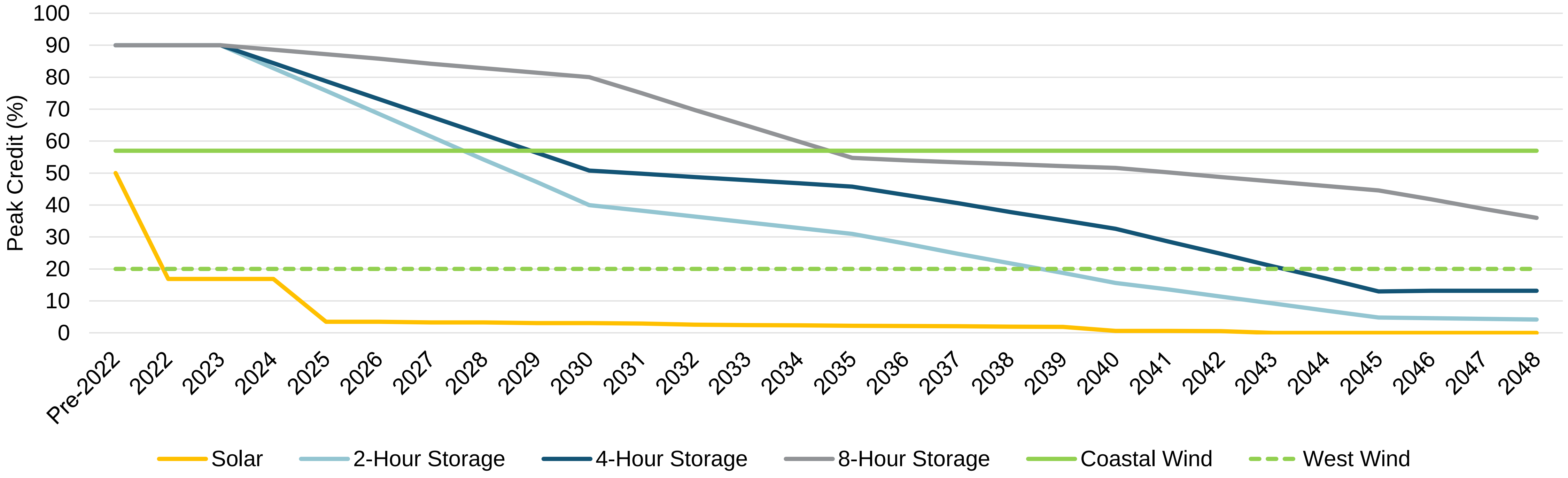
APPENDIX B:

RESERVE MARGIN ASSUMPTIONS

Reserve Margin Assumptions

Parameter	Assumption
Reserve Margin on CPS Energy Native Load Peak	13.75 – 15.00%
Market Purchase Limit	4% of annual native load
Market Sale Limit	20% of annual native load



APPENDIX C:

TECHNOLOGY AVAILABILITY & BUILD LIMITS

Technology Availability and Build Limits

<table>
<tr><th rowspan="2">Technology</th><th rowspan="2">Block Size (MW)</th><th rowspan="2">First Available Year</th><th colspan="3">Annual Build Limit (MW) 2026 - 2030</th><th colspan="3">Annual Build Limit (MW) 2031 - 2040</th><th colspan="3">Annual Build Limit (MW) 2041 +</th></tr>
<tr><th>P1 (Gas)</th><th>P2/P4 (Blend)</th><th>P3/P5-P9 (RES)</th><th>P1 (Gas)</th><th>P2/P4 (Blend)</th><th>P3/P5-P9 (RES)</th><th>P1 (Gas)</th><th>P2/P4 (Blend)</th><th>P3/P5-P9 (RES)</th></tr>
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<tr><td>Reciprocating Internal Combustion Engines (11 Units)</td><td>202</td><td>2027</td><td colspan="2">404</td><td></td><td colspan="2">404</td><td></td><td colspan="2">404</td><td></td></tr>
<tr><td>Coastal Wind</td><td>100</td><td>2026</td><td></td><td>300</td><td>400</td><td></td><td colspan="2">400</td><td></td><td colspan="2">500</td></tr>
<tr><td>West Wind</td><td>100</td><td>2026</td><td></td><td>300</td><td>400</td><td></td><td colspan="2">400</td><td></td><td colspan="2">500</td></tr>
<tr><td>Solar</td><td>100</td><td>2026</td><td></td><td>300</td><td>400</td><td></td><td>400</td><td>500</td><td></td><td colspan="2">500</td></tr>
<tr><td>2-Hour Lithium Ion Batt.</td><td>50</td><td>2026</td><td></td><td colspan="2">300</td><td></td><td colspan="2">300</td><td></td><td colspan="2">400</td></tr>
<tr><td>4-Hour Lithium Ion Batt.</td><td>50</td><td>2026</td><td></td><td>150</td><td>300</td><td></td><td colspan="2">300</td><td></td><td colspan="2">400</td></tr>
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<tr><td>20-Hour Flow Battery</td><td>50</td><td>2030</td><td></td><td colspan="2">100</td><td></td><td>200</td><td>500</td><td></td><td>300</td><td>500</td></tr>
<tr><td>Enhanced Geothermal</td><td>30</td><td>2030</td><td></td><td colspan="2">300</td><td></td><td colspan="2">300</td><td></td><td colspan="2">600</td></tr>
<tr><td>Hydrogen</td><td>240</td><td>2030</td><td></td><td colspan="2">240</td><td></td><td colspan="2">240</td><td></td><td colspan="2">240</td></tr>
<tr><td>Nuclear – Small Modular</td><td>600</td><td>2030</td><td></td><td>600</td><td></td><td></td><td>600</td><td></td><td></td><td>600</td><td></td></tr>
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Specifying Build Limits

Historical and expected renewable resource additions across ERCOT are significant, but growth may be constrained by supply chain limitations, interconnection requirements, and permitting and construction time

		Solar			Wind			Battery		
	Year	ERCOT Cumulative Installed (MW)	ERCOT Growth (MW)	CPS Energy Share of Growth* (MW)	ERCOT Cumulative Installed (MW)	ERCOT Growth (MW)	CPS Energy Share of Growth* (MW)	ERCOT Cumulative Installed (MW)	ERCOT Growth (MW)	CPS Energy Share of Growth* (MW)
Actual through Aug-22	2020	3,974	1,692	100	25,121	2,083	123	225	10	1
	2021	8,274	4,300	253	28,417	1,261	74	833	122	7
	2022	14,983	6,710	395	38,052	3,296	194	3,468	608	36
Projections from Sep-22 onwards	2023	30,717	15,734	926	40,913	9,635	567	8,322	2,634	155
	2024	39,498	8,781	517	41,916	2,861	168	8,877	4,855	286
	Range			***100 - 926***			***74 - 567***			***1 - 286***

Source: ERCOT – Resource Capacity Trend Charts

- For wind and solar, capacity additions across ERCOT (adjusted for CPS Energy's share of ERCOT demand) have been around 100 – 900 MW per year, with a large increase expected for 2023 before declining in 2024. CPS Energy annual build "limits" have been specified based on these ERCOT-wide observations, with slightly lower near-term limits to account for transmission constraints and supply chain issues.
- Capacity additions for storage are expected to increase over the next few years, and CPS Energy annual build "limits" assume that 300 MW per year could be acquired for various duration types. Build limits for longer-duration storage are limited in the short-term, but grow over time to reflect expectations of technology and supply chain advancement.

**CPS Energy share of energy demand in ERCOT is projected to be around 5.9% over this decade. 5.9% was applied to the total ERCOT-wide growth figure to derive the CPS Energy share of growth.*

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