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January 11, 2024

Public Utility Commission of Texas
Interim Chairman Kathleen Jackson
Commissioner Lori Cobos
Commissioner Jimmy Glotfelty
1701 N. Congress Avenue
Austin, TX 78711

Re: PUC Project No. 54584, *Reliability Standard for the ERCOT Market*

Dear Chairman and Commissioners:

On October 26, 2023, Public Utility Commission of Texas (Commission) Staff filed a memorandum requesting that additional scenarios and sensitivities be incorporated into the reliability standard study and further recommended certain changes to how the study results tables are presented. Electric Reliability Council of Texas, Inc. (ERCOT) has completed the requested scenario iteration and incorporated the recommended results table presentation adjustments. The results tables are attached, as well as a presentation providing the key findings from this iteration.

With respect to Item 4 from Commission Staff's memorandum regarding an analysis of the level of Loss-of-Load Expectation (LOLE) that can be achieved with the net cost cap of Public Utility Regulatory Act § 39.1594(a)(1) in place, ERCOT recommends that the analysis be performed after further Performance Credit Mechanism (PCM) design determinations are made (e.g., defining the net cost cap, determining resource eligibility for PCM participation, etc.). ERCOT requests that this analysis be conducted once the necessary PCM determinations have been made in Project No. 55000.[1]

For next steps in the reliability standard study, ERCOT recommends that the potentially final modeling step is to further limit the range of LOLE frequency scenarios, simulate smaller LOLE increments within that range, and update the scenario portfolios based on the December 2023 Capacity, Demand and Reserves (CDR) Report. This approach is intended to produce a higher-resolution marginal cost curve so that a single LOLE value, or a narrow range of values, can be identified as optimal from a societal cost standpoint.

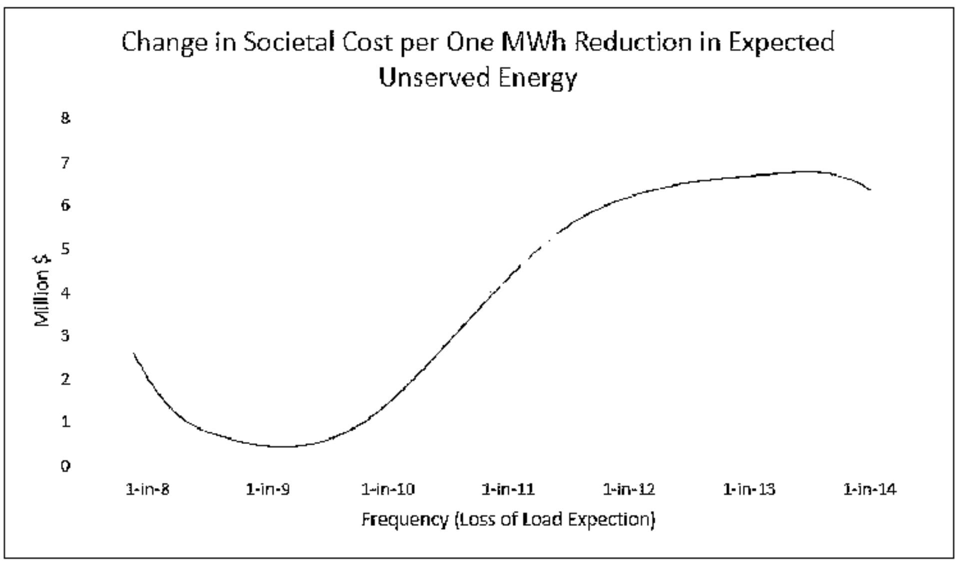
Optimality is defined as the LOLE level that results in the smallest change in societal cost for each megawatt hour (MWh) of avoided Expected Unserved Energy (EUE) as the LOLE level is decreased (for example, from a 1-in-9 LOLE to a 1-in-10). Societal cost is defined as the sum of the market cost, load shed damages (interim Value of Lost Load (VOLL) less the VOLL from the Operating Reserve Demand Curve (ORDC)), and the incremental dispatchable thermal resource cost (combustion turbine (CT) Cost of New Entry (CONE)). Using the more recent

[1] *Performance Credit Mechanism (PCM)*, Project No. 55000.

December 2023 CDR is intended to produce resource portfolios that are more closely aligned with the "Increased IBR" (Inverter Based Resource) sensitivity.

An outline of the suggested simulation approach is as follows:

- Use the December 2023 CDR report as the starting point for portfolio development for study year 2026;
- Create portfolios that result in the following LOLE frequencies (one loss-of-load day in X years): 1-in-7, 1-in-8, 1-in-9, 1-in-10, 1-in-11, 1-in-12, 1-in-13, and 1-in-14;
- 900 MW retirement scenario assumption;
- 42 weather years;
- Base thermal unplanned outage reduction due to weatherization, 85%;
- Use the interim VOLL Option 2a value of $24,693 per MWh presented in the VOLL Study Literature Review and Interim VOLL filing in Project No. 55837;[2]
- Develop the marginal cost curve; points along the curve reflect the change in societal cost per one MWh reduction in EUE. For example:



- ERCOT would provide an accompanying results table in the Commission's preferred reporting format that shows incremental resource capacities, detailed cost inputs, EUE, maximum duration, maximum magnitude, and exceedance probability columns.

Another set of cost information that may be of interest to the Commission is to determine the incremental societal cost of not exceeding the three maximum magnitude and duration threshold pairs evaluated for the simulations: 15-hour duration/14 gigawatt (GW) magnitude, 10-

[2] *See Value of Lost Load*, Project No. 55837, VOLL Study Literature Review and Interim VOLL at 2 (Dec. 21, 2023) (table presenting options for interim VOLL).

hour duration/10 GW magnitude, 5-hour duration/5 GW magnitude. For each LOLE scenario modeled, an increment of CT capacity is added if the maximum duration and/or magnitude exceeded the three thresholds. The amount added would be sufficient to meet the duration and magnitude thresholds. This is equivalent to building the LOLE scenarios with 0% exceedance probabilities. Note that determining these incremental costs would entail additional simulations. ERCOT suggests that the approach be tried for just the 1-in-10 frequency portfolio to see if the results are meaningful. If so, the approach can be extended to other LOLE portfolios.

If the Commission would like ERCOT to pursue this simulation, it is anticipated to take four to five weeks (mid February) to complete. ERCOT's reliability standard analysis would then be concluded, subject to any further scenario narrowing direction from the Commission. ERCOT appreciates any feedback that the Commission may have on this iteration and the proposed additional simulation. ERCOT personnel will be available at the January 18, 2023 Open Meeting to present and answer any questions.

Respectfully submitted,

/s/ Kristi J. Hobbs

Kristi J. Hobbs
Vice President
System Planning & Weatherization
khobbs@ercot.com

Reliability Standard Study: Modeling Results for PUCT Scenarios and Sensitivities (Phase 3)

January 8, 2024

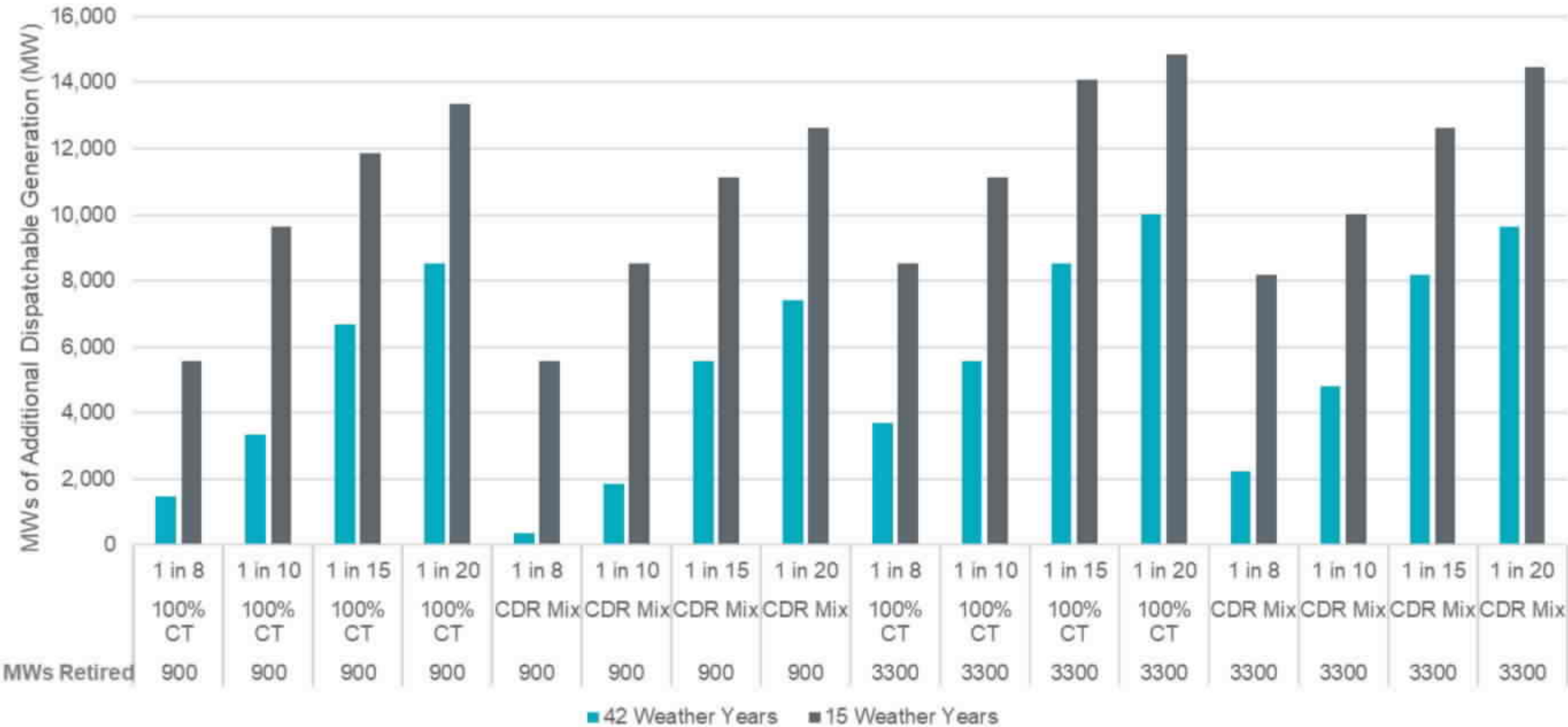
Findings Summary

- Fifteen Weather Years Sensitivity
  - Around 5 GW more generation capacity is needed to reach the same expected loss of load frequency (LOLE) if the range of future weather conditions is bounded by the most recent 15 weather years rather than 42 years used for the Base Case. This supplementary generation capacity significantly reduces max duration, max magnitude and Expected Unserved Energy (EUE).
- Increased Inverter Based Resource (IBR) Portfolio Sensitivity
  - A significant increase of IBR capacity is needed to reach a 1-in-10 frequency. With 3,300 MW retirements, more than 60 GW of additional IBR capacity is needed to reach a 1-in-10 frequency. Over 120 GW of IBR capacity increase is needed to reach a 1-in-20 frequency.
  - The average proportions of additional IBR capacity by technology type across the scenarios is: wind = 9%, solar = 67%, battery storage = 24%; these proportions are based on planned resources in the May 2023 CDR.
- Weatherization Effectiveness Sensitivity
  - A higher weatherization success rate reduces the additional CT capacity required to reach the same frequency. An improvement of 1% in the weatherization success rate translates to a reduction of approximately 175 MW of CT capacity.
- Expected Unserved Energy (EUE) across all Sensitivities
  - Most of the loss-of-load events, and largest EUE amounts, take place in the winter season; the sensitivities had little or no impact on non-winter EUE levels.

Findings Summary (Continued)

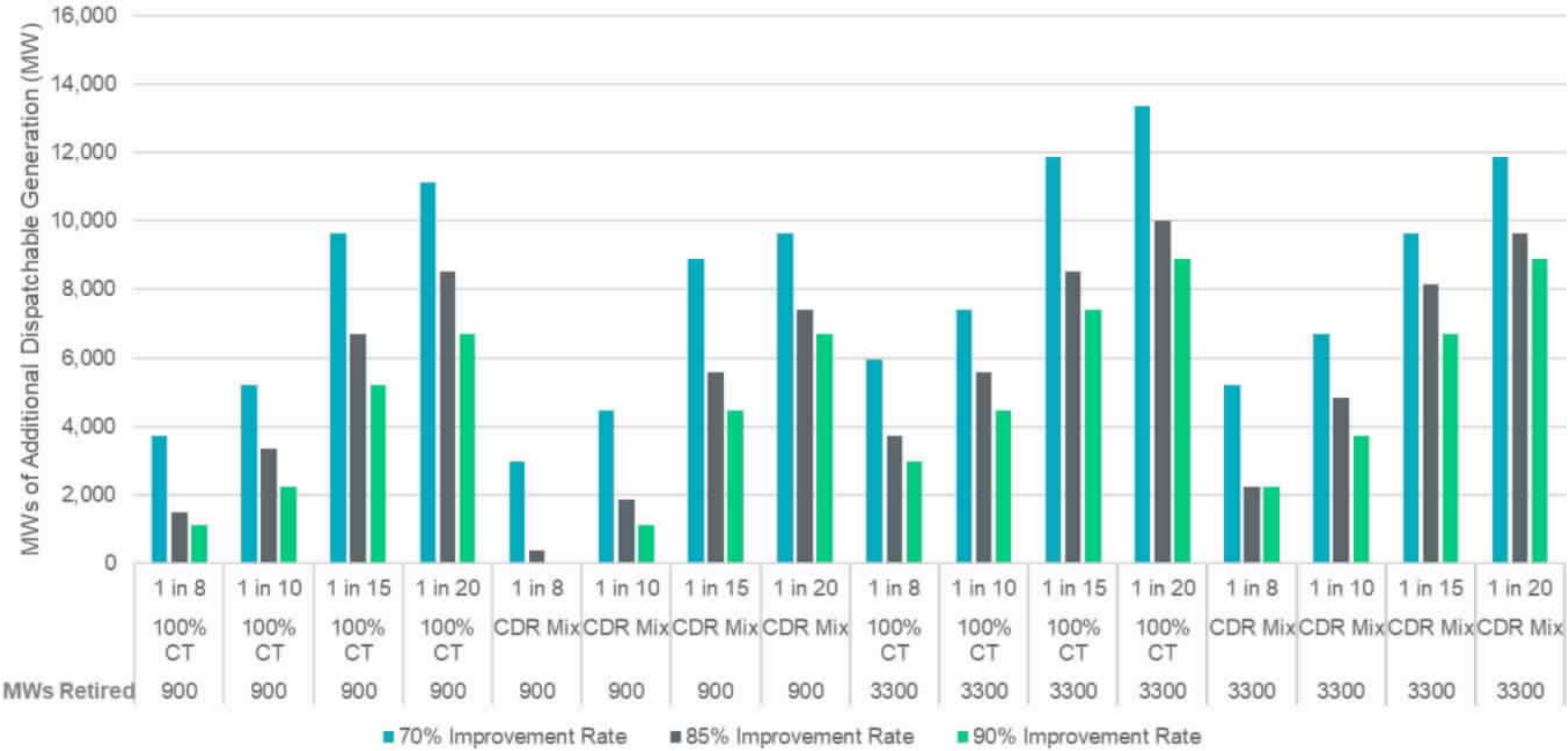
- Replacement of 1-in-5 Frequency Scenarios with 1-in-8 frequency scenarios:
  - Starting with the 1-in-5 frequency scenarios, the amount of additional CT capacity needed to reach a 1-in-8 frequency ranges from 371 MW to 3,710 MW across all scenarios, depending on the retirement assumptions and IBR capacity mixes for the 100% CT and CDR Mix scenarios.
  - The EUE of the 1-in-8 frequency scenarios is around 60% of the EUE for the 1-in-5 frequency scenarios.
  - Compared to the 1-in-5 frequency scenarios, the max duration drops two hours in two of the four 1-in-8 frequency scenarios ("900 MW retirement/CDR Mix" and "3,300 MW retirement/100% CT"). There is no duration drop for the "900 MW retirement/100% CT" and "3,300 MW retirement, CDR Mix").
  - The max magnitude decreases around 1,500 MW on average, or 6%, with the 1-in-8 frequency scenario replacement.
  - Compared to 1-in-5 frequency scenarios, the market cost decrease ranges from 1% to 4% for the 1-in-8 frequency scenarios.

Additional Dispatchable Generation Comparison: 15 Weather Years vs. 42 Weather Years



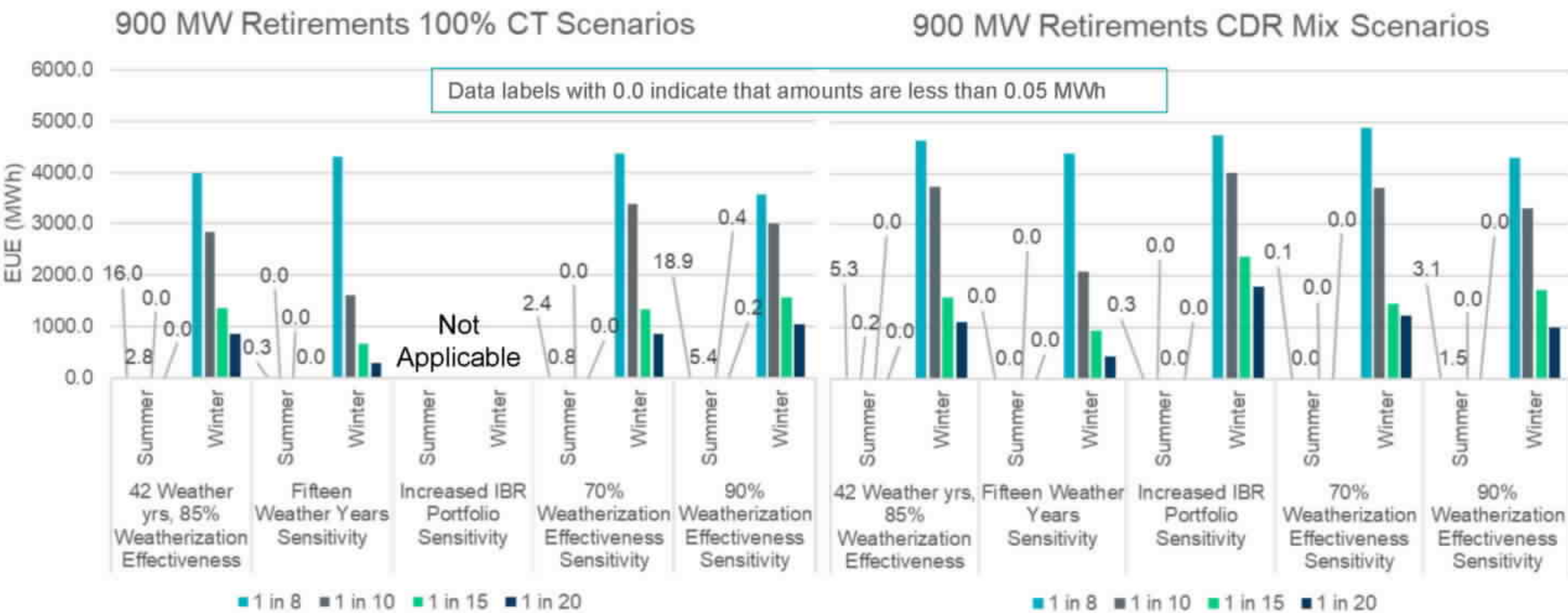
Key Takeaway: Around 5 GW more generation capacity is needed to reach the same frequency if future weather resembles the most recent 15 simulated years. This supplementary generation capacity significantly reduces max duration, max magnitude and EUE.

Impacts of Weatherization Effectiveness



Key Takeaway: A higher weatherization success rate reduces the additional CT capacity required to reach the same expected frequency. An improvement of 1% in weatherization success rate translates to a saving of approximately 175 MW of CT capacity.

Summer and Winter Expected Unserved Energy: 900 MW Retirement Scenarios



Key Takeaway: Summer EUE impacts are negligible across the scenarios; most of the loss of load events, and largest EUE magnitudes, take place in the winter season. The maximum amount of non-winter EUE realized across the scenarios is no more than 2% of the total EUE.

Summer and Winter Expected Unserved Energy: 3,300 MW Retirement Scenarios

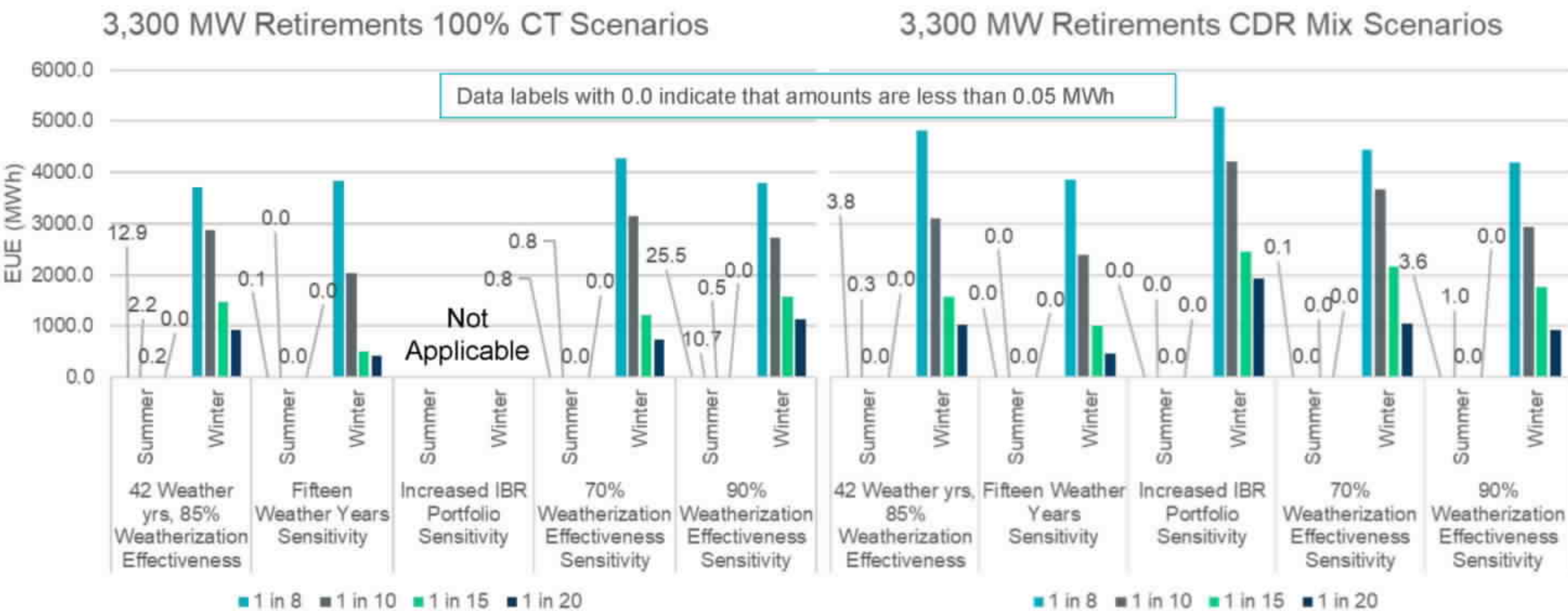


Table 1. Base Case

	Reliability Standard Framework Inputs	Scenario Parameters				Scenario Outcomes																				
																	DURATION				MAGNITUDE					
No.	FREQUENCY (LOLE)	MW Retired	Capacity Mix to Achieve Frequency Target: 100% CT vs. May CDR proportional mix of planned Wind, Solar, ESR, Gas	Portfolio Reserve Margin for Summer*	Portfolio Reserve Margin for Winter*	Expected Unserved Energy EUE (MWh)	Load Shed Damages (EUE * VOLL) (million $/yr)	Coal Capacity Reduction (MW)	MWs of Additional (new) Dispatchable Generation	Fixed Cost of Additional CT Generation (million $/yr)	Total Variable Costs (million $/yr)	Total Variable Costs - EUE at VOLL $5,000/MWh (million $/yr)	CT and Variable Cost (million $/yr)	CT and Variable Cost + Load Shed Damages (million $/yr)	Market Cost (million $/yr)**	Customer Cost + Load Shed Damages + CT Cost (million $/yr)	Max Duration	Exceedance Probability Required for Duration 15 hours	Exceedance Probability Required for Duration 10 hours	Exceedance Probability Required for Duration 5 hours	Max Magnitude	Exceedance Probability Required for Magnitude 14,000 MW	Exceedance Probability Required for Magnitude 10,000 MW	Exceedance Probability Required for Magnitude 5,000 MW	Annual Incremental Fixed Cost of EUE Reduction (GT Cost$/year per MWh of avoided EUE)	Annual Incremental CT and Variable Cost of EUE Reduction (Total $/year per MWh of avoided EUE)
1	1 in 5	900	100% CT	12%	16%	6,177	31	965	0	0	14,969	14,938	14,938	14,969	8,898	8,929	15	0.02%	4.25%	4.76%	26,508	2.21%	4.82%	9.47%	--	
2	1 in 8	900	100% CT	15%	20%	4,012	20	0	1,484	177	14,866	14,845	15,022	15,042	8,803	9,000	15	0.02%	3.33%	3.49%	25,298	1.41%	3.16%	6.32%	81,569	$ 38,721
3	1 in 10	900	100% CT	17%	22%	2,846	14	0	3,339	397	14,827	14,813	15,210	15,224	8,790	9,202	15	0.02%	2.76%	2.90%	22,092	1.07%	2.13%	4.72%	189,354	$ 161,272
4	1 in 15	900	100% CT	21%	27%	1,341	7	0	6,678	795	14,788	14,782	15,576	15,583	8,716	9,517	14	0.00%	1.41%	1.56%	19,941	0.23%	1.18%	2.55%	264,022	$ 243,466
5	1 in 20	900	100% CT	23%	30%	850	4	0	8,533	1,015	14,779	14,775	15,790	15,795	8,655	9,675	13	0.00%	0.86%	1.03%	18,253	0.17%	0.69%	1.77%	448,983	$ 434,863
6	1 in 5	900	CDR Mix	12%	15%	7,991	40	3,000	0	0	14,928	14,888	14,888	14,928	9,615	9,655	17	0.06%	5.16%	6.08%	27,154	3.54%	6.36%	11.47%	--	
7	1 in 8	900	CDR Mix	15%	20%	4,656	23	0	371	44	14,812	14,788	14,832	14,856	9,243	9,310	15	0.02%	3.66%	3.89%	25,711	2.04%	3.77%	6.72%	13,236	$ (16,555)
8	1 in 10	900	CDR Mix	17%	22%	3,735	19	0	1,855	221	14,771	14,752	14,973	14,992	9,217	9,457	14	0.00%	2.93%	3.39%	25,386	1.54%	3.03%	5.54%	191,737	$ 152,820
9	1 in 15	900	CDR Mix	21%	27%	1,590	8	0	5,565	662	14,724	14,716	15,378	15,386	9,052	9,722	13	0.00%	1.28%	1.90%	20,195	0.53%	1.30%	3.05%	205,861	$ 188,896
10	1 in 20	900	CDR Mix	23%	30%	1,104	6	0	7,420	883	14,718	14,712	15,595	15,601	8,978	9,866	13	0.00%	0.88%	1.37%	17,701	0.36%	0.97%	2.10%	453,921	$ 446,063
11	1 in 5	3,300	100% CT	12%	16%	6,244	31	0	1,113	132	14,928	14,896	15,029	15,060	9,069	9,233	17	0.04%	4.29%	4.88%	25,292	2.17%	4.84%	9.68%	--	
12	1 in 8	3,300	100% CT	15%	20%	3,726	19	0	3,710	441	14,859	14,841	15,282	15,301	8,944	9,404	15	0.02%	3.28%	3.50%	24,012	1.33%	2.91%	6.04%	122,727	$ 100,607
13	1 in 10	3,300	100% CT	17%	22%	2,866	14	0	5,565	662	14,831	14,817	15,479	15,493	8,889	9,565	14	0.00%	2.74%	2.86%	20,725	1.07%	2.23%	4.40%	256,618	$ 228,618
14	1 in 15	3,300	100% CT	21%	27%	1,480	7	0	8,533	1,015	14,806	14,799	15,814	15,821	8,773	9,796	14	0.00%	1.49%	1.66%	18,916	0.32%	1.28%	2.72%	254,781	$ 241,757
15	1 in 20	3,300	100% CT	22%	29%	918	5	0	10,017	1,192	14,803	14,798	15,990	15,995	8,706	9,903	13	0.00%	0.99%	1.09%	16,462	0.15%	0.86%	2.17%	314,415	$ 314,098
16	1 in 5	3,300	CDR Mix	12%	16%	7,422	37	400	0	0	14,884	14,847	14,847	14,884	9,533	9,570	15	0.02%	4.99%	5.77%	26,947	3.20%	6.11%	10.93%	--	
17	1 in 8	3,300	CDR Mix	15%	19%	4,832	24	0	2,226	265	14,801	14,777	15,042	15,066	9,381	9,670	15	0.02%	3.73%	4.11%	24,742	1.94%	4.00%	7.14%	102,258	$ 75,368
18	1 in 10	3,300	CDR Mix	18%	23%	3,105	16	0	4,823	574	14,761	14,746	15,319	15,335	9,237	9,826	14	0.00%	2.59%	3.14%	24,055	1.18%	2.57%	4.95%	179,032	$ 160,745
19	1 in 15	3,300	CDR Mix	21%	28%	1,572	8	0	8,162	971	14,739	14,731	15,702	15,710	9,056	10,035	13	0.00%	1.26%	1.68%	20,931	0.59%	1.28%	2.90%	259,039	$ 249,678
20	1 in 20	3,300	CDR Mix	23%	30%	1,034	5	0	9,646	1,148	14,735	14,730	15,878	15,883	8,983	10,136	13	0.00%	0.95%	1.28%	17,679	0.23%	0.88%	2.10%	328,703	$ 325,938

Table 2. Fifteen Weather Years Sensitivity

	Reliability Standard Framework Inputs	Scenario Parameters				Scenario Outcomes																			
																DURATION				MAGNITUDE					
No.	FREQUENCY (LOLE)	MW Retired	Capacity Mix to Achieve Frequency Target: 100% CT vs. May CDR proportional mix of planned Wind, Solar, ESR, Gas	Portfolio Reserve Margin for Summer*	Portfolio Reserve Margin for Winter*	Expected Unserved Energy EUE (MWh)	Load Shed Damages (EUE * VOLL) (million $/yr)	MWs of Additional (new) Dispatchable Generation	Fixed Cost of Additional CT Generation (million $/yr)	Total Variable Costs (million $/yr)	Total Variable Costs - EUE at VOLL $5,000/MWh (million $/yr)	CT and Variable Cost (million $/yr)	CT and Variable Cost + Load Shed Damages (million $/yr)	Market Cost (million $/yr)**	Customer Cost + Load Shed Damages + CT Cost (million $/yr)	Max Duration	Exceedance Probability Required for Duration 15 hours	Exceedance Probability Required for Duration 10 hours	Exceedance Probability Required for Duration 5 hours	Max Magnitude	Exceedance Probability Required for Magnitude 14,000 MW	Exceedance Probability Required for Magnitude 10,000 MW	Exceedance Probability Required for Magnitude 5,000 MW	Annual Incremental Fixed Cost of EUE Reduction (GT Cost$/year per MWh of avoided EUE)	Annual Incremental CT and Variable Cost of EUE Reduction (Total $/year per MWh of avoided EUE)
1	1 in 8	900	100% CT	19%	23%	4,308	22	5,565	662	14,841	14,820	15,482	15,504	8,883	9,567	14	0.00%	4.64%	4.96%	21,655	1.07%	3.79%	6.29%	--	
2	1 in 10	900	100% CT	24%	28%	1,596	8	9,646	1,148	14,807	14,799	15,947	15,955	8,741	9,896	12	0.00%	1.76%	2.08%	14,422	0.16%	1.65%	3.95%	179,026	$ 171,368
3	1 in 15	900	100% CT	26%	31%	662	3	11,872	1,413	14,801	14,798	16,210	16,214	8,619	10,035	12	0.00%	0.48%	0.75%	14,014	0.11%	0.43%	2.77%	283,674	$ 282,248
4	1 in 20	900	100% CT	28%	33%	273	1	13,356	1,589	14,792	14,791	16,380	16,382	8,513	10,104	11	0.00%	0.21%	0.27%	10,896	0.00%	0.16%	1.44%	453,555	$ 435,991
5	1 in 8	900	CDR Mix	20%	24%	4,382	22	5,565	662	14,767	14,745	15,408	15,429	9,193	9,878	13	0.00%	3.68%	4.59%	19,267	1.92%	3.52%	6.13%	--	
6	1 in 10	900	CDR Mix	24%	28%	2,093	10	8,533	1,015	14,745	14,735	15,750	15,761	9,048	10,074	13	0.00%	1.65%	2.61%	17,564	0.69%	1.87%	5.01%	154,300	$ 149,672
7	1 in 15	900	CDR Mix	27%	32%	925	5	11,130	1,324	14,737	14,732	16,057	16,062	8,895	10,224	11	0.00%	0.37%	1.01%	13,068	0.00%	0.59%	2.77%	264,538	$ 262,631
8	1 in 20	900	CDR Mix	28%	34%	431	2	12,614	1,501	14,733	14,731	16,232	16,234	8,836	10,339	10	0.00%	0.00%	0.27%	10,859	0.00%	0.11%	1.92%	357,530	$ 354,718
9	1 in 8	3,300	100% CT	20%	24%	3,826	19	8,533	1,015	14,849	14,830	15,846	15,865	8,924	9,959	13	0.00%	4.16%	4.53%	17,283	1.12%	3.41%	6.13%	--	
10	1 in 10	3,300	100% CT	23%	27%	2,044	10	11,130	1,324	14,834	14,824	16,148	16,158	8,810	10,145	12	0.00%	1.87%	2.56%	14,407	0.11%	1.49%	4.85%	173,372	$ 169,716
11	1 in 15	3,300	100% CT	26%	31%	513	3	14,098	1,678	14,818	14,815	16,493	16,495	8,630	10,310	11	0.00%	0.21%	0.37%	11,727	0.00%	0.16%	2.35%	230,699	$ 225,154
12	1 in 20	3,300	100% CT	27%	32%	415	2	14,840	1,766	14,819	14,817	16,583	16,585	8,591	10,359	11	0.00%	0.16%	0.43%	11,295	0.00%	0.11%	1.81%	902,416	$ 925,311
13	1 in 8	3,300	CDR Mix	21%	25%	3,858	19	8,162	971	14,783	14,763	15,735	15,754	9,196	10,186	13	0.00%	3.20%	4.32%	20,339	1.55%	3.41%	5.87%	--	
14	1 in 10	3,300	CDR Mix	23%	27%	2,389	12	10,017	1,192	14,768	14,756	15,948	15,960	9,102	10,306	13	0.00%	2.35%	3.15%	16,345	0.48%	2.51%	4.96%	150,271	$ 145,124
15	1 in 15	3,300	CDR Mix	26%	31%	1,005	5	12,614	1,501	14,757	14,752	16,253	16,258	8,956	10,462	11	0.00%	0.59%	1.55%	14,776	0.11%	0.75%	3.20%	223,353	$ 220,803
16	1 in 20	3,300	CDR Mix	28%	33%	469	2	14,469	1,722	14,753	14,750	16,472	16,475	8,848	10,573	11	0.00%	0.16%	0.59%	10,211	0.00%	0.16%	2.19%	411,842	$ 408,708

Table 3. "Increased IBR" Portfolio Sensitivity

	Reliability Standard Framework Inputs	Scenario Parameters				Scenario Outcomes																			
																DURATION				MAGNITUDE					
No.	FREQUENCY (LOLE)	MW Retired	Capacity Mix to Achieve Frequency Target: 100% CT vs. May CDR proportional mix of planned Wind, Solar, ESR, Gas	Portfolio Reserve Margin for Summer*	Portfolio Reserve Margin for Winter*	Expected Unserved Energy EUE (MWh)	Load Shed Damages (EUE * VOLL) (million $/yr)	MWs of Additional (new) Dispatchable Generation	Fixed Cost of Additional CT Generation (million $/yr)	Total Variable Costs (million $/yr)	Total Variable Costs - EUE at VOLL $5,000/MWh (million $/yr)	CT and Variable Cost (million $/yr)	CT and Variable Cost + Load Shed Damages (million $/yr)	Market Cost (million $/yr)**	Customer Cost + Load Shed Damages + CT Cost (million $/yr)	Max Duration	Exceedance Probability Required for Duration 15 hours	Exceedance Probability Required for Duration 10 hours	Exceedance Probability Required for Duration 5 hours	Max Magnitude	Exceedance Probability Required for Magnitude 14,000 MW	Exceedance Probability Required for Magnitude 10,000 MW	Exceedance Probability Required for Magnitude 5,000 MW	Annual Incremental Fixed Cost of EUE Reduction (GT Cost$/year per MWh of avoided EUE)	Annual Incremental CT and Variable Cost of EUE Reduction (Total $/year per MWh of avoided EUE)
1	1 in 8	900	CDR Mix	18%	18%	4,742	24	0	0	14,542	14,518	14,518	14,542	8,901	8,925	14	0.00%	3.62%	4.15%	24,436	2.04%	3.92%	6.90%	--	
2	1 in 10	900	CDR Mix	26%	22%	4,011	20	0	0	14,071	14,051	14,051	14,071	8,419	8,439	13	0.00%	2.82%	3.70%	23,587	1.60%	3.71%	5.87%	0	$ (639,745)
3	1 in 15	900	CDR Mix	46%	31%	2,387	12	0	0	13,202	13,190	13,190	13,202	8,324	8,336	11	0.00%	0.46%	2.72%	21,298	0.95%	2.42%	4.25%	0	$ (530,117)
4	1 in 20	900	CDR Mix	54%	35%	1,799	9	0	0	12,939	12,930	12,930	12,939	8,342	8,351	11	0.00%	0.13%	2.32%	20,513	0.67%	1.83%	3.64%	0	$ (441,739)

5	1 in 8	3,300	CDR Mix	27%	21%	5,284	26	0	0	13,896	13,869	13,869	13,896	8,440	8,466	13	0.00%	3.22%	4.46%	25,144	2.63%	4.72%	7.33%	--	
6	1 in 10	3,300	CDR Mix	37%	26%	4,216	21	0	0	13,448	13,427	13,427	13,448	8,382	8,403	12	0.00%	1.73%	3.98%	22,975	2.04%	4.17%	5.90%	0	$ (413,985)
7	1 in 15	3,300	CDR Mix	57%	35%	2,456	12	0	0	12,767	12,754	12,754	12,767	8,469	8,481	11	0.00%	0.15%	2.97%	20,900	1.16%	2.86%	4.51%	0	$ (382,187)
8	1 in 20	3,300	CDR Mix	67%	40%	1,933	10	0	0	12,482	12,472	12,472	12,482	8,513	8,522	11	0.00%	0.04%	2.34%	20,114	0.86%	2.29%	3.62%	0	$ (540,044)

Table 4. 70% Weatherization Effectiveness Sensitivity

	Reliability Standard Framework Inputs	Scenario Parameters				Scenario Outcomes																			
																DURATION				MAGNITUDE					
No.	FREQUENCY (LOLE)	MW Retired	Capacity Mix to Achieve Frequency Target: 100% CT vs. May CDR proportional mix of planned Wind, Solar, ESR, Gas	Portfolio Reserve Margin for Summer*	Portfolio Reserve Margin for Winter*	Expected Unserved Energy EUE (MWh)	Load Shed Damages (EUE * VOLL) (million $/yr)	MWs of Additional (new) Dispatchable Generation	Fixed Cost of Additional CT Generation (million $/yr)	Total Variable Costs (million $/yr)	Total Variable Costs - EUE at VOLL $5,000/MWh (million $/yr)	CT and Variable Cost (million $/yr)	CT and Variable Cost + Load Shed Damages (million $/yr)	Market Cost (million $/yr)**	Customer Cost + Load Shed Damages + CT Cost (million $/yr)	Max Duration	Exceedance Probability Required for Duration 15 hours	Exceedance Probability Required for Duration 10 hours	Exceedance Probability Required for Duration 5 hours	Max Magnitude	Exceedance Probability Required for Magnitude 14,000 MW	Exceedance Probability Required for Magnitude 10,000 MW	Exceedance Probability Required for Magnitude 5,000 MW	Annual Incremental Fixed Cost of EUE Reduction (GT Cost$/year per MWh of avoided EUE)	Annual Incremental CT and Variable Cost of EUE Reduction (Total $/year per MWh of avoided EUE)
1	1 in 8	900	100% CT	17%	20%	4,378	22	3,710	441	14,833	14,811	15,252	15,274	8,866	9,329	15	0.02%	3.28%	3.68%	24,557	1.85%	3.75%	6.74%	--	
2	1 in 10	900	100% CT	19%	22%	3,379	17	5,194	618	14,811	14,795	15,413	15,429	8,836	9,471	15	0.02%	2.91%	3.24%	22,845	1.43%	2.78%	5.58%	176,728	$ 160,611
3	1 in 15	900	100% CT	24%	28%	1,338	7	9,646	1,148	14,783	14,777	15,924	15,931	8,668	9,823	14	0.00%	1.37%	1.64%	18,812	0.42%	1.09%	2.80%	259,672	$ 250,891
4	1 in 20	900	100% CT	25%	30%	840	4	11,130	1,324	14,775	14,771	16,096	16,100	8,613	9,941	13	0.00%	0.84%	1.09%	19,442	0.23%	0.69%	2.04%	354,089	$ 343,157
5	1 in 8	900	CDR Mix	17%	21%	4,887	24	2,968	353	14,765	14,740	15,094	15,118	9,260	9,637	15	0.02%	3.66%	4.21%	25,243	1.98%	3.90%	7.03%	--	
6	1 in 10	900	CDR Mix	19%	23%	3,730	19	4,452	530	14,743	14,724	15,254	15,273	9,183	9,731	14	0.00%	3.05%	3.45%	23,982	1.66%	3.30%	5.54%	152,729	$ 138,679
7	1 in 15	900	CDR Mix	24%	29%	1,461	7	8,904	1,060	14,718	14,711	15,770	15,777	8,962	10,029	13	0.00%	1.12%	1.77%	23,493	0.38%	1.43%	2.76%	233,427	$ 227,444
8	1 in 20	900	CDR Mix	25%	30%	1,218	6	9,646	1,148	14,712	14,706	15,853	15,860	8,932	10,086	12	0.00%	0.97%	1.47%	19,393	0.50%	1.20%	2.61%	363,465	$ 342,840
9	1 in 8	3,300	100% CT	17%	20%	4,278	21	5,936	706	14,836	14,814	15,521	15,542	8,974	9,701	15	0.02%	3.41%	3.94%	27,955	1.73%	3.52%	6.65%	--	
10	1 in 10	3,300	100% CT	19%	22%	3,142	16	7,420	883	14,822	14,807	15,690	15,705	8,887	9,785	15	0.02%	2.95%	3.16%	21,757	1.05%	2.57%	5.26%	155,446	$ 148,835
11	1 in 15	3,300	100% CT	24%	28%	1,213	6	11,872	1,413	14,800	14,794	16,207	16,213	8,688	10,107	13	0.00%	1.22%	1.41%	20,242	0.30%	1.03%	2.55%	274,662	$ 267,974
12	1 in 20	3,300	100% CT	25%	30%	730	4	13,356	1,589	14,798	14,794	16,384	16,387	8,627	10,220	13	0.00%	0.80%	0.90%	19,126	0.11%	0.65%	1.92%	365,594	$ 366,433
13	1 in 8	3,300	CDR Mix	17%	21%	4,445	22	5,194	618	14,767	14,745	15,363	15,385	9,286	9,927	14	0.00%	3.52%	3.83%	26,911	1.87%	3.77%	6.80%	--	
14	1 in 10	3,300	CDR Mix	19%	23%	3,674	18	6,678	795	14,759	14,741	15,536	15,554	9,204	10,017	15	0.02%	2.97%	3.37%	24,844	1.58%	3.22%	5.50%	228,856	$ 223,770
15	1 in 15	3,300	CDR Mix	22%	27%	2,153	11	9,646	1,148	14,742	14,731	15,879	15,890	9,045	10,204	14	0.00%	1.81%	2.34%	19,309	0.80%	1.81%	3.49%	232,291	$ 225,867
16	1 in 20	3,300	CDR Mix	25%	30%	1,053	5	11,872	1,413	14,733	14,728	16,141	16,146	8,951	10,369	13	0.00%	0.76%	1.35%	17,536	0.32%	0.90%	2.46%	240,867	$ 237,787

Table 5. 90% Weatherization Effectiveness Sensitivity

	Reliability Standard Framework Inputs	Scenario Parameters				Scenario Outcomes																			
																DURATION				MAGNITUDE					
No.	FREQUENCY (LOLE)	MW Retired	Capacity Mix to Achieve Frequency Target: 100% CT vs. May CDR proportional mix of planned Wind, Solar, ESR, Gas	Portfolio Reserve Margin for Summer*	Portfolio Reserve Margin for Winter*	Expected Unserved Energy EUE (MWh)	Load Shed Damages (EUE * VOLL) (million $/yr)	MWs of Additional (new) Dispatchable Generation	Fixed Cost of Additional CT Generation (million $/yr)	Total Variable Costs (million $/yr)	Total Variable Costs - EUE at VOLL $5,000/MWh (million $/yr)	CT and Variable Cost (million $/yr)	CT and Variable Cost + Load Shed Damages (million $/yr)	Market Cost (million $/yr)**	Customer Cost + Load Shed Damages + CT Cost (million $/yr)	Max Duration	Exceedance Probability Required for Duration 15 hours	Exceedance Probability Required for Duration 10 hours	Exceedance Probability Required for Duration 5 hours	Max Magnitude	Exceedance Probability Required for Magnitude 14,000 MW	Exceedance Probability Required for Magnitude 10,000 MW	Exceedance Probability Required for Magnitude 5,000 MW	Annual Incremental Fixed Cost of EUE Reduction (GT Cost$/year per MWh of avoided EUE)	Annual Incremental CT and Variable Cost of EUE Reduction (Total $/year per MWh of avoided EUE)
1	1 in 8	900	100% CT	14%	17%	3,584	18	1,113	132	14,873	14,855	14,988	15,006	8,770	8,921	15	0.02%	3.03%	3.22%	24,007	1.30%	2.78%	5.90%	--	
2	1 in 10	900	100% CT	15%	18%	3,018	15	2,226	265	14,842	14,827	15,092	15,107	8,771	9,051	15	0.02%	2.80%	3.01%	22,220	1.01%	2.23%	4.82%	234,351	$ 184,832
3	1 in 15	900	100% CT	19%	22%	1,559	8	5,194	618	14,799	14,791	15,409	15,417	8,722	9,348	13	0.00%	1.58%	1.79%	17,831	0.53%	1.22%	2.65%	242,005	$ 216,928
4	1 in 20	900	100% CT	20%	24%	1,034	5	6,678	795	14,786	14,781	15,576	15,581	8,698	9,498	13	0.00%	1.12%	1.18%	16,129	0.29%	0.93%	2.13%	336,656	$ 318,588
5	1 in 8	900	CDR Mix	14%	17%	4,313	22	0	0	14,819	14,798	14,798	14,819	9,192	9,214	15	0.02%	3.39%	3.79%	23,800	1.60%	3.37%	6.74%	--	
6	1 in 10	900	CDR Mix	15%	18%	3,333	17	1,113	132	14,783	14,766	14,899	14,915	9,202	9,351	14	0.00%	2.88%	3.18%	23,263	1.28%	2.61%	5.41%	135,161	$ 103,077
7	1 in 15	900	CDR Mix	19%	23%	1,724	9	4,452	530	14,729	14,721	15,251	15,259	9,085	9,623	13	0.00%	1.47%	2.06%	19,611	0.53%	1.47%	3.12%	247,047	$ 218,782
8	1 in 20	900	CDR Mix	22%	26%	1,002	5	6,678	795	14,718	14,713	15,508	15,513	8,989	9,789	13	0.00%	0.88%	1.31%	18,234	0.27%	0.90%	2.08%	366,634	$ 355,946
9	1 in 8	3,300	100% CT	14%	16%	3,818	19	2,968	353	14,869	14,850	15,203	15,222	8,955	9,327	15	0.02%	3.37%	3.54%	22,740	1.37%	2.80%	5.96%	--	
10	1 in 10	3,300	100% CT	15%	18%	2,741	14	4,452	530	14,841	14,827	15,357	15,371	8,882	9,426	14	0.00%	2.63%	2.76%	21,335	0.99%	2.13%	4.42%	164,025	$ 143,013
11	1 in 15	3,300	100% CT	19%	22%	1,578	8	7,420	883	14,812	14,804	15,687	15,695	8,795	9,686	13	0.00%	1.56%	1.77%	18,339	0.30%	1.20%	2.57%	303,816	$ 284,047
12	1 in 20	3,300	100% CT	20%	24%	1,127	6	8,904	1,060	14,805	14,799	15,859	15,865	8,740	9,806	13	0.00%	1.18%	1.33%	17,803	0.19%	1.01%	2.02%	390,980	$ 380,633
13	1 in 8	3,300	CDR Mix	14%	17%	4,206	21	2,226	265	14,797	14,776	15,041	15,062	9,346	9,632	14	0.00%	3.52%	3.81%	23,981	1.71%	3.31%	5.98%	--	
14	1 in 10	3,300	CDR Mix	16%	19%	2,937	15	3,710	441	14,772	14,757	15,198	15,213	9,245	9,701	14	0.00%	2.63%	2.95%	22,128	1.18%	2.42%	4.74%	139,149	$ 124,376
15	1 in 15	3,300	CDR Mix	19%	23%	1,757	9	6,678	795	14,747	14,738	15,533	15,541	9,100	9,903	13	0.00%	1.50%	1.98%	19,833	0.63%	1.54%	2.95%	299,314	$ 283,199
16	1 in 20	3,300	CDR Mix	21%	26%	925	5	8,904	1,060	14,736	14,731	15,791	15,795	9,006	10,070	13	0.00%	0.80%	1.22%	16,566	0.19%	0.84%	1.87%	318,248	$ 310,248

* Reserve margins are calculated with Effective Load Carrying Capabilities for wind, solar, battery storage, and non-PUN thermal resources.

** Market Costs: The sum of wholesale energy costs attributable to serving load, plus Ancillary Service costs. Market Cost is calculated outside the model using the following model metrics: Market Cost = Load * Market Price + Spin Supplied * Spin Weighted Price + Reg-Up Supplied * Reg-Up Weighted Price + Non-Spin Supplied * Non-Spin Weighted Price). Note that Spin plus Reg-Up represents all real-time online reserves. For this calculation, SERVM distinguishes only Spin and Reg-Up because separate online reserve variables for modeling various emergency actions are used. Reg-Up is 1,500 MW to reflect the amount preserved during load shed. "Spin Supplied" captures all other real-time online reserves.

<u>Cost Parameters</u>

VOLL ($/MWh)	$	5,000.00
CONE ($/MW-year)	$	119,000.00

The table below illustrates the three steps to building the portfolios: (1) initial removal of coal capacity to create the least reliable portfolios (1 in 5 frequency), (2) removal of coal and gas capacity to achieve the scenario retirement levels, and (3) the addition of combustion turbine or IBR or both types of capacity to achieve the remaining frequency levels.

Section 1: Base Case

900 MW Retirement Scenario												
	Initial Portfolios		100% CT Scenario					CDR Mix				
Resource Type	Dec 2022 CDR	Portfolio after Retiring 900 MW of Gas Capacity	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 8 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 8 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal	13,630	13,630	(965)					(3,000)				
Gas	55,415	54,515										
Wind	41,853	41,853										
Solar	44,775	44,775						782	782	782	782	782
Battery Storage	10,945	10,945						3,082	3,082	3,082	3,082	3,082
New CTs	-	-		1,484	3,339	6,678	8,533		371	1,855	5,565	7,420
TOTAL	**166,618**	**165,718**	**164,753**	**167,202**	**169,057**	**172,396**	**174,251**	**166,582**	**169,953**	**171,437**	**175,147**	**177,002**

3,300 MW Retirement Scenario												
	Initial Portfolios		100% CT Scenario					CDR Mix				
Resource Type	Dec 2022 CDR	Portfolio after Retiring 3,300 MW (900 Gas/2,400 Coal)	Capacity Changes to Achieve 1 in 5 Frequency	Capacity Changes to Achieve 1 in 8 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency	Capacity Change to Achieve 1 in 5 Frequency*	Capacity Changes to Achieve 1 in 8 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal	13,630	11,230						(400)				
Gas	55,415	54,515	-		-	-	-	-		-	-	-
Wind	41,853	41,853										
Solar	44,775	44,775	-		-	-	-	782	782	782	782	782
Battery Storage	10,945	10,945						3,082	3,082	3,082	3,082	3,082
New CTs	-	-	1,113	3,710	5,565	8,533	10,017	-	2,226	4,823	8,162	9,646
TOTAL	**166,618**	**163,318**	**164,431**	**167,028**	**168,883**	**171,851**	**173,335**	**166,782**	**169,408**	**172,005**	**175,344**	**176,828**

* For the CDR Mix scenario, the addition of IBR resources reduces the amount of coal capacity needed to achieve the 1 in 5 frequency target relative to the amount needed for the 100% CT scenario.

Section 2: Fifteen Weather Years Sensitivity

900 MW Retirement Scenario								
	100% CT Scenario							
Resource Type	Capacity Changes to Achieve 1 in 8 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency	Capacity Changes to Achieve 1 in 8 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal								
Gas								
Wind								
Solar					782	782	782	782
Battery Storage					3,082	3,082	3,082	3,082
New CTs	5,565	9,646	11,872	13,356	5,565	8,533	11,130	12,614
TOTAL	**171,283**	**175,364**	**177,590**	**179,074**	**175,147**	**178,115**	**180,712**	**182,196**

3,300 MW Retirement Scenario								
	100% CT Scenario							
Resource Type	Capacity Changes to Achieve 1 in 8 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency	Capacity Changes to Achieve 1 in 8 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal								
Gas								
Wind								
Solar					782	782	782	782
Battery Storage					3,082	3,082	3,082	3,082
New CTs	8,533	11,130	14,098	14,840	8,162	10,017	12,614	14,469
TOTAL	**171,851**	**174,448**	**177,416**	**178,158**	**175,344**	**177,199**	**179,796**	**181,651**

Section 3: IBR Sensitivity

900 MW Retirement Scenario				
Resource Type	Capacity Changes to Achieve 1 in 8 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal				
Gas				
Wind	820	2,460	6,560	8,200
Solar	6,789	18,802	48,834	60,847
Battery Storage	5,240	9,555	20,343	24,658
New CTs				
TOTAL	**178,566**	**196,534**	**241,455**	**259,424**

3,300 MW Retirement Scenario				
Resource Type	Capacity Changes to Achieve 1 in 8 Frequency	Capacity Changes to Achieve 1 in 10 Frequency	Capacity Changes to Achieve 1 in 15 Frequency	Capacity Changes to Achieve 1 in 20 Frequency
Coal				
Gas				
Wind	3,280	5,330	9,430	11,480

Solar	24,808	39,825	69,857	84,874
Battery Storage	11,713	17,107	27,895	33,289
New CTs	-	-	-	-
TOTAL	**203,119**	**225,579**	**270,500**	**292,960**

Section 4: 70% Weatherization Effectiveness Sensitivity

900 MW Retirement Scenario								
	100% CT Scenario							
Resource Type	**Capacity Changes to Achieve 1 in 8 Frequency**	**Capacity Changes to Achieve 1 in 10 Frequency**	**Capacity Changes to Achieve 1 in 15 Frequency**	**Capacity Changes to Achieve 1 in 20 Frequency**	**Capacity Changes to Achieve 1 in 8 Frequency**	**Capacity Changes to Achieve 1 in 10 Frequency**	**Capacity Changes to Achieve 1 in 15 Frequency**	**Capacity Changes to Achieve 1 in 20 Frequency**
Coal								
Gas								
Wind								
Solar					782	782	782	782
Battery Storage					3,082	3,082	3,082	3,082
New CTs	3,710	5,194	9,646	11,130	2,968	4,452	8,904	9,646
TOTAL	**169,428**	**170,912**	**175,364**	**176,848**	**172,550**	**174,034**	**178,486**	**179,228**

3,300 MW Retirement Scenario								
	100% CT Scenario							
Resource Type	**Capacity Changes to Achieve 1 in 8 Frequency**	**Capacity Changes to Achieve 1 in 10 Frequency**	**Capacity Changes to Achieve 1 in 15 Frequency**	**Capacity Changes to Achieve 1 in 20 Frequency**	**Capacity Changes to Achieve 1 in 8 Frequency**	**Capacity Changes to Achieve 1 in 10 Frequency**	**Capacity Changes to Achieve 1 in 15 Frequency**	**Capacity Changes to Achieve 1 in 20 Frequency**
Coal	-	-	-	-		-	-	-
Gas								
Wind	-	-	-	-		-	-	-
Solar					782	782	782	782
Battery Storage	-	-	-	-	3,082	3,082	3,082	3,082
New CTs	5,936	7,420	11,872	13,356	5,194	6,678	9,646	11,872
TOTAL	**169,254**	**170,738**	**175,190**	**176,674**	**172,376**	**173,860**	**176,828**	**179,054**

Section 5: 90% Weatherization Effectiveness Sensitivity

900 MW Retirement Scenario								
	100% CT Scenario							
Resource Type	**Capacity Changes to Achieve 1 in 8 Frequency**	**Capacity Changes to Achieve 1 in 10 Frequency**	**Capacity Changes to Achieve 1 in 15 Frequency**	**Capacity Changes to Achieve 1 in 20 Frequency**	**Capacity Changes to Achieve 1 in 8 Frequency**	**Capacity Changes to Achieve 1 in 10 Frequency**	**Capacity Changes to Achieve 1 in 15 Frequency**	**Capacity Changes to Achieve 1 in 20 Frequency**
Coal								
Gas								
Wind								
Solar					782	782	782	782
Battery Storage					3,082	3,082	3,082	3,082
New CTs	1,113	2,226	5,194	6,678	-	1,113	4,452	6,678
TOTAL	**166,831**	**167,944**	**170,912**	**172,396**	**169,582**	**170,695**	**174,034**	**176,260**

3,300 MW Retirement Scenario								
	100% CT Scenario							
Resource Type	**Capacity Changes to Achieve 1 in 8 Frequency**	**Capacity Changes to Achieve 1 in 10 Frequency**	**Capacity Changes to Achieve 1 in 15 Frequency**	**Capacity Changes to Achieve 1 in 20 Frequency**	**Capacity Changes to Achieve 1 in 8 Frequency**	**Capacity Changes to Achieve 1 in 10 Frequency**	**Capacity Changes to Achieve 1 in 15 Frequency**	**Capacity Changes to Achieve 1 in 20 Frequency**
Coal								
Gas	-	-	-	-		-	-	-
Wind								
Solar	-	-	-	-	782	782	782	782
Battery Storage					3,082	3,082	3,082	3,082
New CTs	2,968	4,452	7,420	8,904	2,226	3,710	6,678	8,904
TOTAL	**166,286**	**167,770**	**170,738**	**172,222**	**169,408**	**170,892**	**173,860**	**176,086**