Supplementary Information: System-level Impacts of Voluntary Carbon-free Electricity Procurement Strategies

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1. Supplementary Methods

1.1. Modeling Voluntary Carbon-Free Electricity Procurement

This section of SI provides further details on the approach to modeling to volumetric, temporal, and emissions matching strategies discussed in Section 1.1.1 of the main text, and provides the mathematical formulations of novel constraints introduced in this paper. We describe the framework in the context of specific regions within the territory of the U.S. Western Electricity Coordinating Council (or WECC) but the framework itself can be applied to other power systems as well. To start, we divide of electricity into sets α and β:

- Set α (or the participants) refers to the consumers that participate in the voluntary procurement program. They procure carbon-free generation capacity to match their electricity demand according to the chosen strategy. To better match procured electricity, they can also modify their load pattern by utilizing demand flexibility and procuring and operating storage facilities.

- Set β refers to all other consumers in the grid, who do not participate in voluntary carbon-free electricity procurement. Their only incentive is to minimize the cost of their own electricity consumption, and they are able to utilize demand flexibility in pursuing this goal.

For simplicity, we focus in this paper on groups of voluntary participants located within the same geographic region. In each case, we assume there is only one set of consumers that participates in voluntary procurement. This single set of participants could represent an aggregation of customers procuring together, served by a common retailer, or using a liquid secondary market for time-based clean energy attributes with effectively no transaction costs. Thus, a natural extension of this paper is to consider multiple participants with diverse demand profiles or access to different generation resources as well as the role of transaction costs and trading of time-based energy attributes; we leave this extension to future studies.

Resources (power plants G_P and storage facilities G_S) are divided into into two Groups.

- Voluntary carbon-free electricity suppliers (G_1). This resource group includes all resources that are able to be procured by voluntary market participants. In this study, these are limited to new-build carbon-free resources located in the same model zone as the participating voluntary consumers.

- Other electricity suppliers (G_2). This resource group includes all resources in WECC not included in G_1.

This distinction allows the model to keep track of the resources that serve voluntary matching participants while accurately reflecting constraints on the aggregate deployment of certain resource types in a given region (e.g. wind, solar, and geothermal). The set of resources G_2 in fact contains representations of every generation and storage resource that exists or is available for future deployment in WECC. The set G_1 contains *copies* of all resources in G_2 that meet the qualifications for voluntary procurement i.e. new-build, carbon-free (or storage), and located in the same model zone as the participating demand. The resources included in G_1 share maximum capacity limits with their counterparts in G_2, such that if either resource is deployed by the model, the maximum deployment potential of its counterpart shrinks. Thus a given amount of the available resource potential may be built to supply either voluntary matching participants or the bulk electricity market, but not both simultaneously.

1.1.1. Volumetric Matching

Modeling volumetric matching does not require the addition of any novel constraints to GenX. Rather, a new constraint is added to the set of existing energy share requirement (ESR) constraints present in the reference model, which represent state RPS and CES policies. The new constraint sets an annual matching target equal to the annual sum of participating load from consumers in set α, and allows all resources in set G_1 to qualify toward meeting this target. The participating load in set α is also removed from any other ESR constraints in the model that would have applied to it previously, and new copies of these constraints (e.g. California's in-state RPS requirement) are created for this load exclusively to ensure compliance.

1.1.2. Temporal Matching

We model temporal matching using a framework similar to the one used in previous work (Xu et al., 2021), but with several simplifications. While the formulation used in Xu et al. (2021) evaluated progress toward a temporal matching target based on both direct procurement of carbon-free electricity and the share of carbon-free electricity in the overall grid mix, we assume in this paper that no grid power can be counted toward a matching target.

Under temporal matching, there are three novel constraint added to GenX and applied to the set of participating consumers α. The first constraint introduced is the "Hourly Matching" constraint, $\forall t \in T$:

$$L_t^{\alpha} + \sum_{y \in F^{\alpha}} (U_{y,t} - D_{y,t}) + \sum_{y \in G_S \cap G_1} (C_{y,t} - P_{y,t}) = \sum_{y \in G_P \cap G_1} P_{y,t} + GS_t - EX_t, \quad (1)$$

where L_t^{α} denotes participants' load at hour t, $U_{y,t}$ and $D_{y,t}$ denote the increase and decrease of flexible demand, $C_{y,t}$ and $P_{y,t}$ denote the charge of storage and power output of storage and power plants. Here, subscripts P and S of the set G refer to storage and power plants respectively, GS_t denotes the grid supply and EX_t denotes excess generation beyond the level of participating demand. The left-hand side of the constraint shows that consumer Group α utilizes demand flexibility ($y \in F^{\alpha}$) and procured storage facilities ($y \in G_S \cap G_1$) to modify the demand for easier matching with procured carbon-free electricity; therefore the left-hand side is also called the modified demand in our context. The right-hand side of the constraint shows that if the procured generation ($\sum_{y \in G_P \cap G_1} P_{y,t}$) is below the modified demand, grid supply (GS_t) will fill the gap; on the other hand, if the procured CFE is above the modified demand, excess will occur (EX_t).

The second set of constraint is the "Excess Limit":

$$\sum_{t \in T} EX_t \leq ExcessLimit \times \sum_{t \in T} \left(L_t^{\alpha} + \sum_{y \in G_S \cap G_1} (C_{y,t} - P_{y,t}) \right), \tag{2}$$

which states the total amount of hourly excess generation cannot be higher than a certain level on an annual basis. This limit is set to approximate participants' unwillingness to over-procure energy that creates uncertain spillover effects and increases exposure to risk.

Before introducing the temporal matching target constraint, we need to introduce the mathematical expression of **Consumed carbon-free electricity**:

$$ConsumedCFE_t = \sum_{y \in G_P \cap G_1} P_{y,t} - EX_t \tag{3}$$

Finally, the last constraint is the "temporal matching target":

$$\frac{\sum_{t \in T} (ConsumedCFE_t)}{\sum_{t \in T} \left(L_t^{\alpha} + \sum_{y \in G_S \cap G_1} (C_{y,t} - P_{y,t}) \right)} \geq CFE_{Target} \tag{4}$$

This constraint requires that the ratio of the total consumed carbon-free electricity to the total load (plus net storage loss) over the year must be higher than a certain target.

1.1.3. Emissions Matching

An emissions matching requirement is modeled by calculating the "emissions impact" of electricity consumption and voluntary carbon-free electricity procurement at all hours using short-run marginal emissions rates (SRMERs), and ensuring that the annual sum of the calculated impact is less than zero. The following "emissions matching" constraint represents this requirement:

$$\sum_{t \in T} SRMER \times \left(L_t^{\alpha} + \sum_{y \in F^{\alpha}} (U_{y,t} - D_{y,t}) + \sum_{y \in G_S \cap G_1} (C_{y,t} - P_{y,t}) - \sum_{y \in G_P \cap G_1} P_{y,t} \right) \leq 0 \tag{5}$$

This constraint ensures that the net emissions offset, as measured via the SRMER, is greater than or equal to the net emissions incurred by the consumer over the year.

Because SRMERs cannot be calculated and optimized against endogenously in a linear capacity expansion model, we use a fixed SRMER time series as an input for the emissions matching constraint. This fixed time series is calculated by taking the results of a reference case run for the emissions matching case being examined, and creating a new case where capacities of all generation, storage, and transmission technologies are held fixed at their optimized values from the reference. An incremental constant demand is then added to the demand profile of the target model zone, equivalent to 5% of the zone's average demand. By measuring the difference in hourly system-wide emissions between this "perturbed" case with fixed capacities and the original reference case, and dividing this difference by the added demand, we calculate an hourly time series of added emissions per unit of added demand, i.e. the SRMER.

The procurement of carbon-free electricity is then optimized against this fixed SRMER time series under an emissions matching strategy. However, it is possible that the procurement of carbon-free electricity or shifting of participating demand in pursuit of an emissions matching target could lead to SRMERs that are different from the ones used in the fixed time series based on the reference case. We therefore repeat the SRMER calculation process, using the system as optimized in the initial emissions matching run as a fixed baseline to which the incremental 5% demand is added. We repeat this process iteratively, re-calculating SRMER time series and re-optimizing the system based on these. We stop the iterative process once impact of the voluntary procurements on system-level emissions (measured compared to the reference case) changes by less than 1% between iterations.

1.2. Additional Modeling Assumptions

We discuss four additional assumptions here, and some of them have been covered in the main text. First of all ($\mathbf{A}_1$) we assumed one (1) group of electricity consumers (e.g., 10% of C&I load form an *alliance* and sign contracts with clean power plants so that their *aggregated* consumption can be matched with clean generation to achieve a matching target. The second assumption ($\mathbf{A}_2$) was that a set of carbon-free resources would be available in the model for participating loads to procure (distinct from general resources available to meet general grid needs). These matching candidates shared the development potential with resources that are available for general grid needs. This assumption also means that participating loads would not contract with any resources already online as of 2021.

Third, we assumed ($\mathbf{A}_3$) that participating loads must also meet existing RPS/CES rules. Furthermore, through PPAs or market-based EAC purchases, participating loads would obtain and completely retire renewable/clean energy credits generated by contracted carbon-free resources to satisfy their RPS/CES obligations and would not resell any excess credits to other parties (e.g. general loads). Finally, for temporal matching cases, we assume ($\mathbf{A}_4$) by default that the annual sum of generation in any hour that is in excess of participating customers' demand in that hour is limited to 80% less than the overall temporal matching target for the case (i.e., $ExcessLimit = CFETarget - 80\%$). This is also the excess limit constraint.

2. Additional Data Assumptions

2.1. Load Assumptions

The subsector-wise demand profiles are calculated with the load time-series in NREL's EFS study (Mai et al., 2018) and modified with the Princeton Net-Zero America study's stock values (Larson et al., 2021). We then allocated the state-level data to each zone with population-weighting method. The full time-series load and C&I load for each zone are available in uploaded datasets (Xu et al., 2023).

2.2. Flexible Demand and Demand Curtailment Assumption

Demand flexibility (time shiftable demand) can be activated to modify the C&I load, making the C&I load easier to be matched with carbon-free electricity supply. If the participation rate of C&I customers in voluntary carbon-free electricity procurement is 10%, then 10% of C&I flexibility will be participating in the voluntary procurement. The amount of shiftable demand in 2030 is shown in Table 1, based on Table 5.1 from Mai et al. (2018).

In addition, 6.7% of total regional demand in California is available as voluntary price-responsive demand curtailment (also known as demand response) at an opportunity cost of $400/MWh for the first 0.3% of load, $1,100/MWh for the next 2.4% of load and $1,800/MWh for the next 4% of load (based on analysis of price-responsive bids in PJM market, Fig. 9 of McAnany (2020)). However, this price responsive demand curtailment does not modify the voluntary participating C&I customer demand profile.

2.3. Transmission Assumptions

GenX's powerflow module currently adopts a transshipment model (also known as pipe-and-bubble modeling), allowing for flexibility in interregional power flow as long as maximum transfer limits are maintained. There are six zones in this study (Figure 1). The starting transmission capability, expansion cost, and loss factor for each corridor is shown in Table 2. The starting capacity is aggregated by Powergenome (Schivley et al., 2022) from the EIA IPM model (U.S. Environmental Protection Agency, 2021). Note that this data assumes the expansion of transmission is continuous given the length of each corridor, so the cost can be approximated by metric of \$/MW-year. We assume in 2030 the final transmission capability between zones can at most be doubled from the starting status, and if the starting capacity is smaller than 1,500 MW, we set the upper bound at 1,500 MW.

2.4. Supply-Side Cost and Operation Assumptions

In this section, we summarize the cost and operation parameter assumptions of our study in Tables 3, 4 and 10. All \$ are in 2020 USD. Detailed data are compiled by Powergenome (Schivley et al., 2022), and are available in uploaded datasets (Xu et al., 2023).

The starting capacities and heat rates are calculated and aggregated by Powergenome (Schivley et al., 2022) from EIA 860m (U.S. Energy Information Administration, 2021c) and EIA 923 (U.S. Energy Information Administration, 2022).

For candidates, we obtained all cost and heat rate assumptions from NREL ATB 2021 (Vimmerstedt et al., 2021), except for the long-duration storage cost assumptions, which we retrieved from Baik et al. (2021) and Mongird et al. (2020). Because we modelled a planning horizon of 10-years (2021-2030), capital costs were averaged from years 2021 to 2030.

The candidate project areas of wind and solar and their respective interconnector cost, time-series, and maximum potential were obtained from (Leslie et al., 2021). The NGCC with carbon capture and sequestration (CCS) are also responsible for the CO_2 pipeline construction cost (added in the annualized CAPEX) (Larson et al., 2021) and the basin specific injection cost (Morgan and Grant, 2017):

- CA_N: \$13.7/metric ton
- CA_S: \$23.4/metric ton

- WECC_NMAZ: \$47.7/metric ton

NGCC with CCS are not allowed to expand in the rest of three zones (WECC_N, WECC_PNW, and WECC_WYCO) because they are too far away from any of the injection basins in U.S.

The fuel cost is from EIA 2021's 2030 fuel projection (U.S. Energy Information Administration, 2021a) and 2019 monthly natural gas variation published by EIA (U.S. Energy Information Administration, 2021b), see numbers in Table 6.

The duration time and efficiency parameters of the storage facilities are shown below:

- Pumped Hydro: 15.5 hours (calculated as the average duration of U.S. pumped hydro facilities. We obtained the raw data are obtained U.S. Department of Energy (2022). We did not allow pumped hydro plants to expand in this study). The Round-trip efficiency is 75%.
- Battery: 1-10 hours. The Round-trip efficiency is 85%.
- Long-duration Storage Metal-Air: 100-200 hours. The Round-trip efficiency is 47%.
- Long-duration Storage Hydrogen: 200-800 hours. The Round-trip efficiency is 27%.

2.5. Resource Adequacy

In this study, we modeled four (4) reserve groups in the WECC, they are:

- California: this reserve group includes CA_N and CA_S with a planning reserve margin of 13.7%.
- Northwest Power Pool - United States (NWPP-US): this reserve group includes WECC_N and WECC_PNW with a planning reserve margin of 15.7%.
- Rocky Mountain Reserve Group (RMRG): this reserve group includes WECC_WYCO with a planning reserve of 13.0%.
- Southwest Reserve Sharing Group (SRSG): this reserve group includes WECC_NMAZ with a planning reserve of 10.0%.

We obtained the planning reserve numbers from NERC's Summer Reliability Assessment Report (North American Electric Reliability Corporation, 2020). For how resource adequacy constraints are modeled in GenX, readers are referred to GenX's github site (MIT Energy Initiative and Princeton University ZERO lab, 2022).

2.6. Policy Assumptions

We obtained the Renewable portfolio standards (RPS) values from LBNL's RPS summary (Barbose, 2021), and aggregated them using population weighting method onto the 6 zones. They are:

- CA_N and CA_S: 60% of load.
- WECC_N: 8.6% of load.
- WECC_NMAZ: 26.0% of load.
- WECC_PNW: 19.3% of load.
- WECC_WYCO: 21.1% of load.

We assume the renewable energy credits can be traded freely among the zones (i.e., RPS values above are modeled with one common WECC-wide RPS constraint). While each state in reality has slightly different criteria for what types of resources qualify under their respective policies, our study assumes that on the margin, load-serving entities in all states in WECC comply with their obligations by procuring new wind and solar resources, which are eligible for all state RPS policies, which thus makes compliance fungible between states (e.g. a MWh of wind or solar could be traded and used in any state RPS). For states that allow large hydropower resources to qualify for their RPS targets (e.g. Washington and Oregon), we assume that the full existing hydro capacity is contributed toward the target and reduce the remaining target accordingly. The remaining modeled compliance requirement reflects demand for existing small hydropower or new wind, solar and geothermal resources that are eligible in any state RPS, and are thus valid to model as an aggregate region-wide requirement. One set of more distinct state-level policies that we do model directly are California's requirement that 75% of its RPS be met with in-state generation, as well as its recent mandate for 1 GW of new geothermal capacity, which we do not allow to count toward C&I voluntary matching targets.

At the federal level, we modeled subsidies for low-carbon generation and storage introduced by the Inflation Reduction Act of 2022 (H.R.5376, 2022). Under the IRA, carbon-free generators are allowed to receive either a 30% investment tax credit (ITC) or a $26/MWh production tax credit (PTC), and storage devices receive a 30% ITC. Bonus credits of 10 percentage points (for the ITC) or 10% ($2.60/MWh, for the PTC) are also available for generators using domestically-manufactured parts or located in "energy communities," and we assume that clean resources on average receive one of these two adders. Based on the economic incentives for each resource type, we assume that offshore wind, geothermal power, and ZCF combined cycle plants will select the ITC, while onshore wind and solar will select the PTC. Because the clean electricity ITC/PTC and storage ITC are not direct-pay, we assume that their effective values are reduced by 7.5% due to the cost of monetization. Gas plants with carbon capture are assumed to opt for the 45Q for carbon capture and sequestration (CCS) credit of $85/ton, and hydrogen storage facilities are assumed to receive the $3/kg 45V PTC for hydrogen production, as long as this production occurs during hours when generation from new-build, local, carbon-free resources is greater than electrolysis demand in the given zone (Ricks et al., 2023). Because resource costs in GenX are inputted as net-present-value-equivalent annuities over a resource's full financial lifetime, and PTCs provided by the IRA last only for the first decade of operation (or 12 years in the case of 45Q), we reduced the modeled value of these PTCs accordingly. For the onshore wind PTC, we obtained an effective annuitized value of $10.33/MWh using the credit lifetime of 10 years, technology financial lifetime of 30 years, and technology-specific WACC of 3.4%. For the solar PTC, the final effective value is $9.62 based on a 30-year lifetime and 2.5% WACC. For hydrogen electrolysis, the effective value of 45V is $1.24/kg based on a credit lifetime of 10 years, a financial lifetime of 25 years, and a WACC of 2.5%. For gas with CCS, the effective value of 45Q is $39.88/ton based on a credit lifetime of 12 years, a financial lifetime of 30 years, and a WACC of $3.9%. These calculations implicitly assume the annual generation of these resources will be the same across the lifetime of the plants.

Supplementary Table 1: Flexible Demand Assumptions

Subsector	Fraction of subsector demand that is considered flexible	Maximum advance in consumption (Hours)	Maximum delay in consumption (Hours)
Commercial Space Heating and Cooling	13%	1	1
Commercial Water Heating	11%	2	2
Residential Space Heating and Cooling	13%	1	1
Residential Water Heating	11%	2	2
Light-Duty Vehicles	67%	0	5

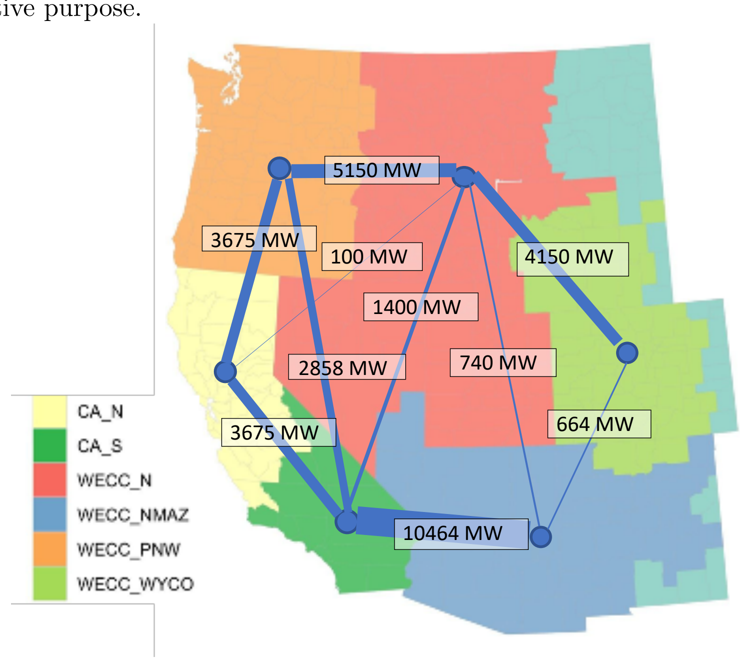
Supplementary Table 2: Transmission Parameters

Lines	From	To	Starting Transmission Capability (MW)	Loss (fraction of power flow)	Max Reinforcement (MW)	Reinforcement Cost ($/MW-year)
1	CA_N	CA_S	3675	0.0337	3675	55061.71
2	CA_N	WECC_N	100	0.049	1500	57538.83
3	CA_N	WECC_PNW	3675	0.0464	3675	75823.06
4	CA_S	WECC_N	1400	0.0556	1500	48991.47
5	CA_S	WECC_NMAZ	10464	0.0447	10464	53523.38
6	CA_S	WECC_PNW	2858	0.0728	2858	86550.95
7	WECC_N	WECC_NMAZ	740	0.0599	1500	50722.25
8	WECC_N	WECC_PNW	5150	0.0387	5150	71038.54
9	WECC_N	WECC_WYCO	4150	0.0384	4150	36949.92
10	WECC_NMAZ	WECC_WYCO	664	0.0485	1500	64641.83

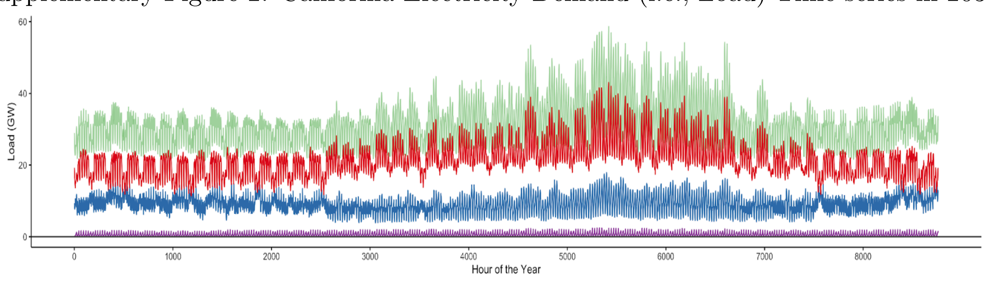
Supplementary Table 3: Pre-subsidy CAPEX, Fixed Operation and Maintenance Cost, Heat Rate, Annual Capacity Factor, and Potential of Technologies - California. Note: hydrogen storage has additional charge capacity costs, including charge capacity CAPEX of 956,000 $/MW, annualized charge capacity CAPEX of 54,045 $/MW-year, and charge capacity FOM of 23,900 $/MW-yr.

Region	Technology	Capacity CAPEX ($/MW)	Annualized Capacity CAPEX ($/MW-year)	Capacity FOM ($/MW-year)	Energy Capacity CAPEX ($/MWh)	Annualized Energy Capacity CAPEX ($/MWh-year)	Energy Capacity FOM ($/MWh-year)	Heat Rate (MMBTU/MWh)	Annual Capacity Factor	Existing Capacity or Potential (GW)
California	Biomass	-	-	149,833	-	-	-	14.11	-	0.42
California	DG Solar	-	-	-	-	-	-	-	26%	11.1
California	Gas CC	-	-	11,969	-	-	-	7.82	-	23.26
California	Gas CT	-	-	11,826	-	-	-	10.66	-	12.56
California	Gas Steam	-	-	43,777	-	-	-	9.59	-	2.92
California	Geothermal	-	-	209,101	-	-	-	8.80	-	1.35
California	Hydro	-	-	47,048	-	-	-	8.77	29.2% - 29.6%	8.99
California	Onshore Wind	-	-	43,000	-	-	-	8.82	20.2% - 40.6%	6.4
California	Pumped Hydro	-	-	40,608	-	-	-	0.78	-	3.75
California	Utility Solar	-	-	22,887	-	-	-	8.98	25.3% - 25.7%	18.36
California	New Battery	216,266	18,261	5,406	204,120	17,235	5,103	-	-	Unlimited
California	New Gas CC	1,036,020	78,086	27,636	-	-	-	6.36	-	Unlimited
California	New Gas CT	894,345	60,917	21,157	-	-	-	9.72	-	Unlimited
California	New Gas w CCS	2,593,228	175,092	65,903	-	-	-	7.16	-	Unlimited
California	New Geothermal	5,647,566	298,520	133,366	-	-	-	-	-	1.71
California	New Geothermal EGS	11,611,685	604,662	204,059	-	-	-	-	-	0.4
California	New LDS Hydrogen	894,345	57,016	21,157	4,700	167	118	-	-	Unlimited
California	New LDS Metal-Air	1,200,000	68,232	30,000	12,000	682	-	-	-	Unlimited
California	New Offshore Wind	4,209,096	424,376	73,042	-	-	-	-	40.9% - 52.8%	13.34
California	New Onshore Wind	1,185,353	135,691	41,294	-	-	-	-	24.8% - 39.7%	33.28
California	New Utility Solar	1,089,501	72,512	20,248	-	-	-	-	30.6% - 31.4%	235.45
California	New ZCF CC	1,036,020	78,086	27,636	-	-	-	6.36	-	Unlimited

Supplementary Figure 1: Western Interconnection network with six (6) zones in total, as well as pre-existing inter-zonal transmission capacities. Nodes' locations are only for demonstrative purpose.



Supplementary Figure 2: California Electricity Demand (i.e., Load) Time-series in 2030.



Supplementary Table 4: Pre-subsidy CAPEX, Fixed Operation and Maintenance Cost, Heat Rate, Annual Capacity Factor, and Potential of Technologies - Wyoming & Colorado. Note: hydrogen storage has additional charge capacity costs, including charge capacity CAPEX of 956,000 \$/MW, annualized charge capacity CAPEX of 51,424 \$/MW-year, and charge capacity FOM of 23,900 \$/MW-yr.

Region	Technology	Capacity CAPEX (\$/MW)	Annualized Capacity CAPEX (\$/MW-year)	Capacity FOM (\$/MW-year)	Energy Capacity CAPEX (\$/MWh)	Annualized Energy Capacity CAPEX (\$/MWh-year)	Energy Capacity FOM (\$/MWh-year)	Heat Rate (MMBTU/MWh)	Annual Capacity Factor	Existing Capacity or Potential (GW)
WY & CO	Biomass	-	-	149,833	-	-	-	12.92	-	0.32
WY & CO	Coal	-	-	65,138	-	-	-	11.18	-	8.69
WY & CO	DG Solar	-	-	-	-	-	-	-	26.1%	0.5
WY & CO	Gas CC	-	-	11,927	-	-	-	8.87	-	4.01
WY & CO	Gas CT	-	-	10,908	-	-	-	11.98	-	3.93
WY & CO	Gas Steam	-	-	51,304	-	-	-	14.67	-	0.48
WY & CO	Hydro	-	-	47,048	-	-	-	-	29.6%	0.99
WY & CO	Onshore Wind	-	-	43,000	-	-	-	-	31.3%	11.32
WY & CO	Pumped Hydro	-	-	40,608	-	-	-	-	-	0.51
WY & CO	Utility Solar	-	-	22,887	-	-	-	-	25.4%	1.45
WY & CO	New Battery	216,266	17,379	5,406	204,120	16,403	5,103	-	-	Unlimited
WY & CO	New Gas CC	1,036,020	49,748	27,636	-	-	-	6.36	-	Unlimited
WY & CO	New Gas CT	894,345	41,999	21,157	-	-	-	9.72	-	Unlimited
WY & CO	New LDS Hydrogen	894,345	39,322	21,157	4,700	159	118	-	-	Unlimited
WY & CO	New LDS Metal-Air	1,200,000	66,467	30,000	12,000	664	-	-	-	Unlimited
WY & CO	New Onshore Wind	1,185,353	80,790	41,294	-	-	-	-	34.7% - 62.2%	105.92
WY & CO	New Utility Solar	1,089,501	55,290	20,248	-	-	-	-	28% - 31.3%	205.16
WY & CO	New ZCF CC	1,036,020	55,116	27,636	-	-	-	6.36	-	Unlimited

Supplementary Table 5: Variable Operation and Maintenance Cost and Unit Commitment Parameters

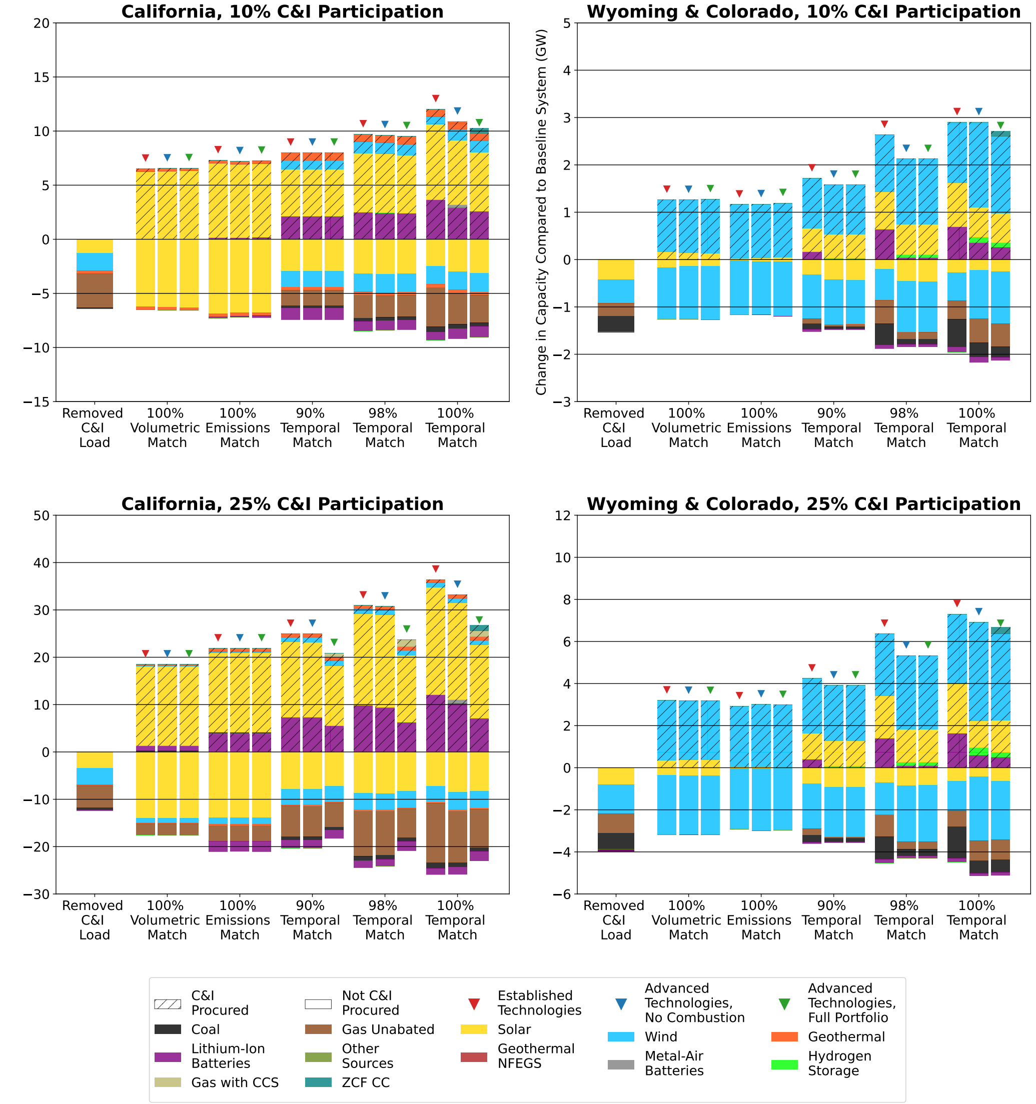
Technology	VOM (\$/MWh)	Minimum Run Capacity (Fraction of Max Capacity)	Ramp-Up Percentage (Fraction of Max Capacity per Hour)	Ramp-Down Percentage (Fraction of Max Capacity per Hour)	Minimum Up Time (Hours)	Minimum Down Time (Hours)
Biomass	4.58	0.25	1.00	1.00	-	-
Coal	1.88	0.27	0.57	0.57	24.00	24.00
Gas CC	3.82	0.35	0.64	0.64	6.00	6.00
Gas CT	5.23	0.37	3.78	3.78	1.00	1.00
Gas Steam	1.06	0.19	0.64	0.64	6.00	6.00
Nuclear	-	0.50	0.25	0.25	24.00	24.00
New Gas CC	1.76	0.20	0.64	0.64	6.00	6.00
New Gas CT	5.00	0.30	3.78	3.78	1.00	1.00
New Gas w CCS	5.80	0.60	0.64	0.64	6.00	6.00
New ZCF CC	1.76	0.20	0.64	0.64	6.00	6.00

Supplementary Table 6: Fuel Assumptions (April price is the original price projected by AEO 2021, and monthly fluctuation multiplier is applied on the April natural gas price.)

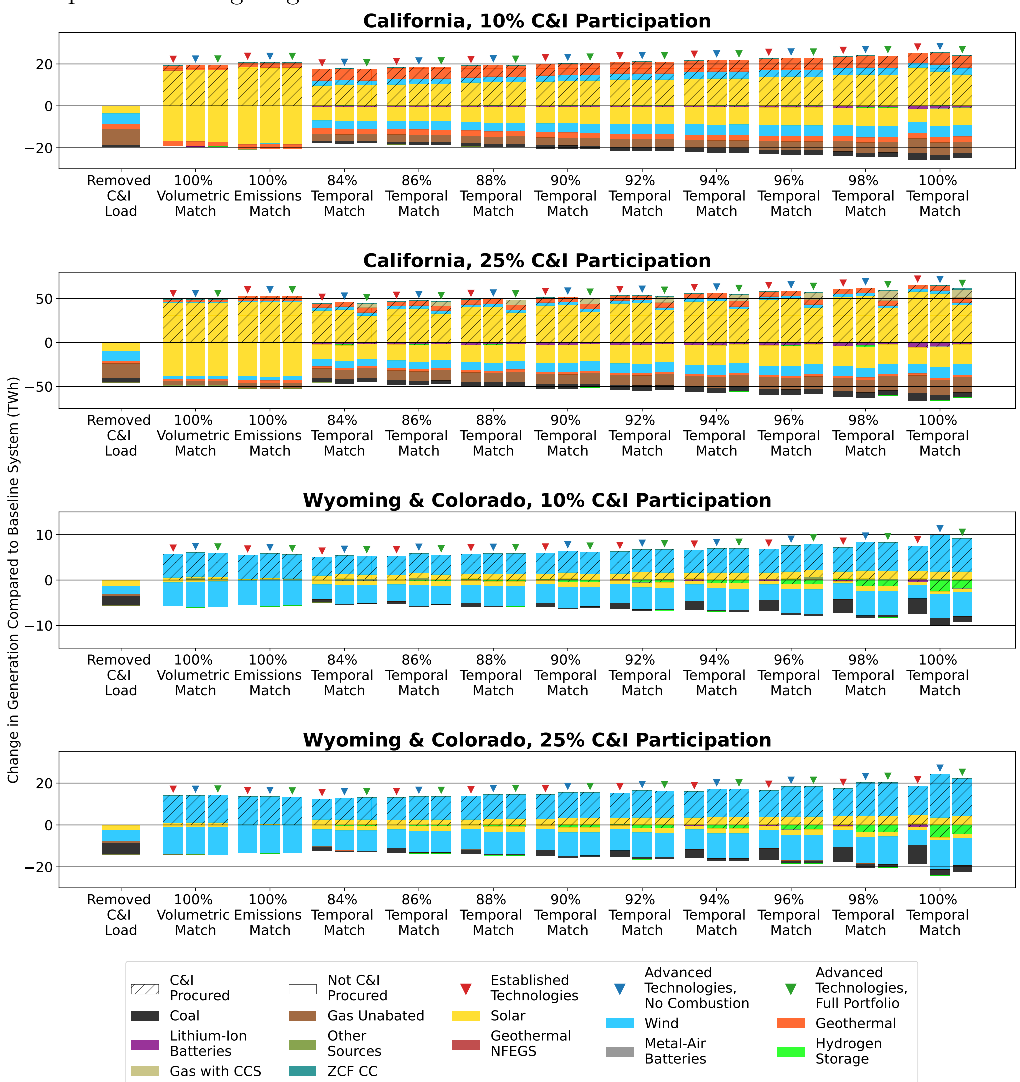
Fuel Name	Carbon Content	Fuel Price (\$/MMBTU)											
	(metric ton of CO_2e per MMBTU)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Biomass	0	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23	3.23
Natural Gas (Pacific)	0.05306	5.33	4.84	4.61	3.83	3.65	3.41	3.37	3.20	3.43	3.30	3.95	3.89
Natural Gas (Mountain)	0.05306	5.50	4.99	4.76	3.95	3.77	3.51	3.47	3.30	3.54	3.41	4.07	4.02
Coal (Mountain)	0.09552	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53
Uranium	0	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Zero-carbon fuel	0	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00

3. Supplementary Results

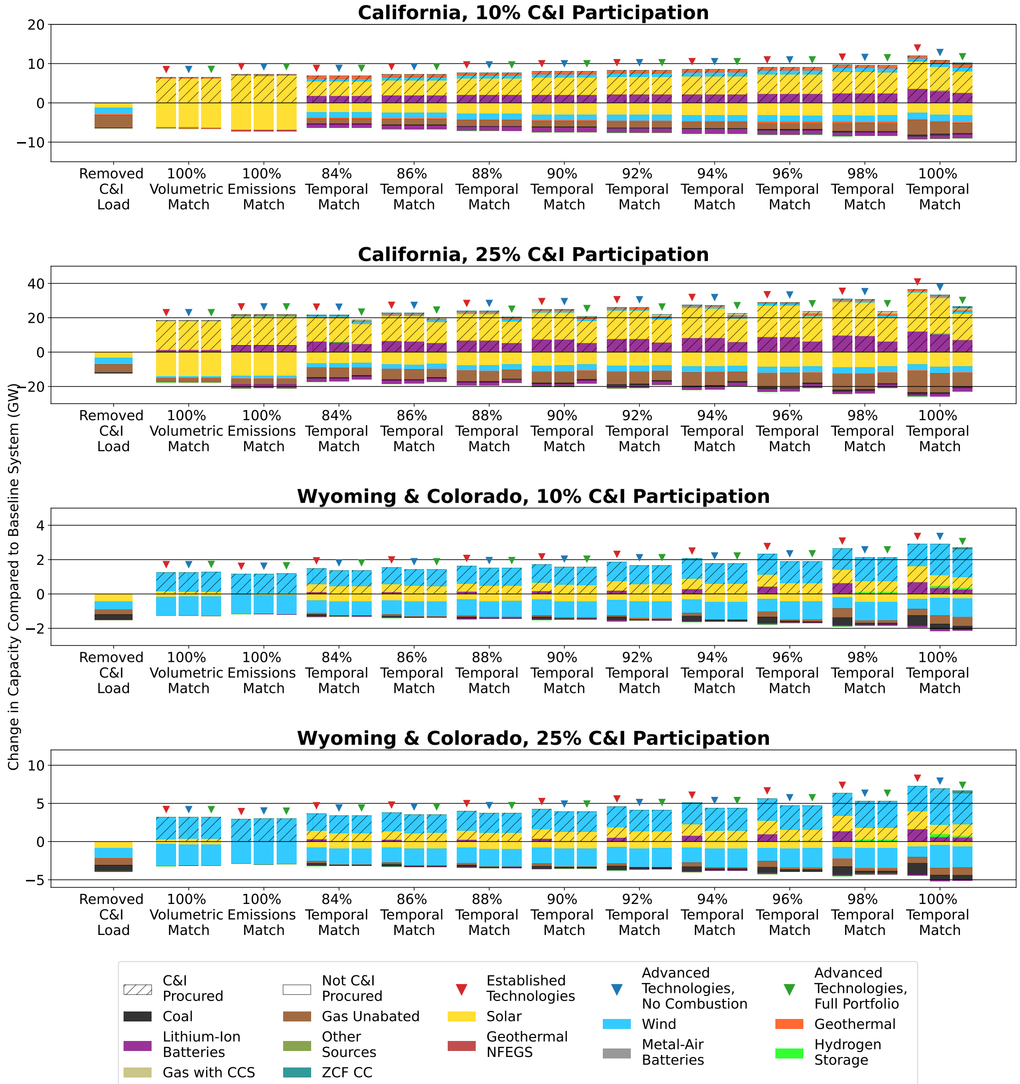
Supplementary Figure 3: System-level changes in installed generating capacity as a result of voluntary carbon-free electricity procurements, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions.



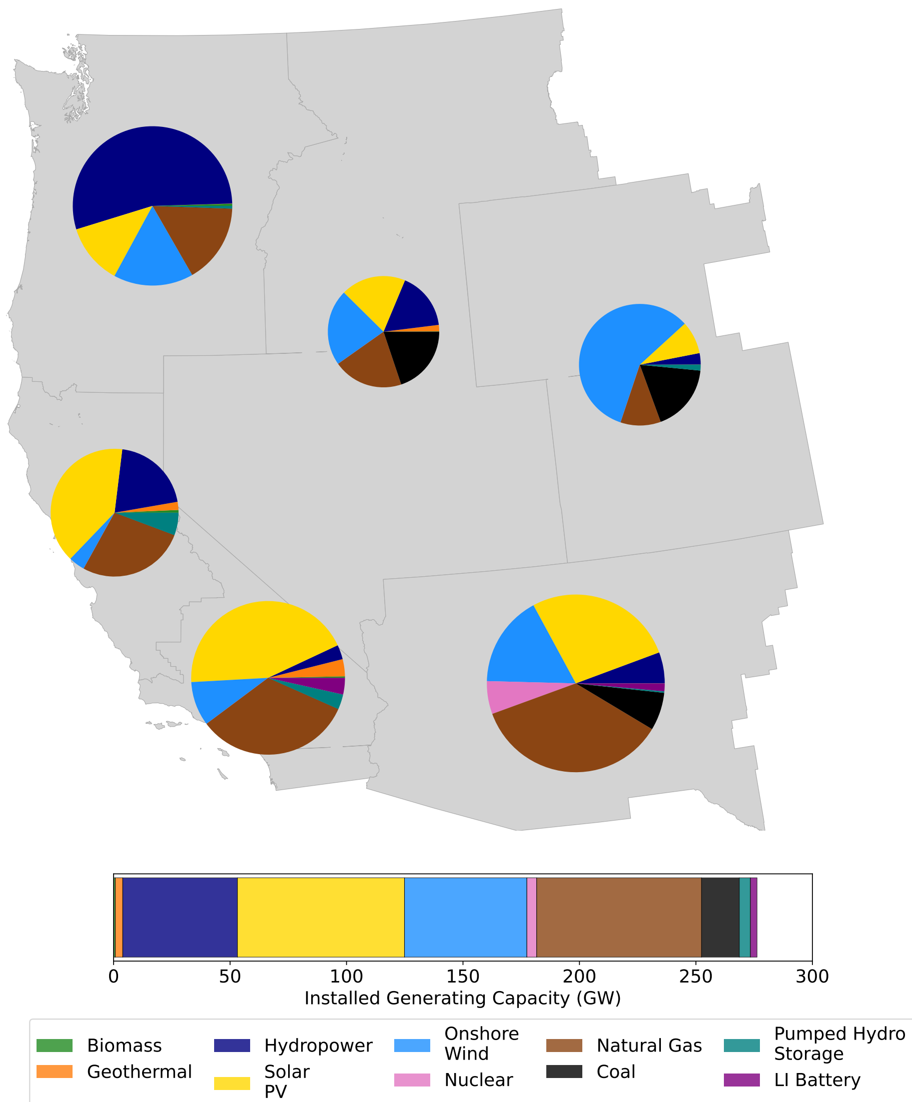
Supplementary Figure 4: System-level changes in generation as a result of voluntary carbon-free electricity procurements, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions, showing outcomes for the full range of temporal matching targets.



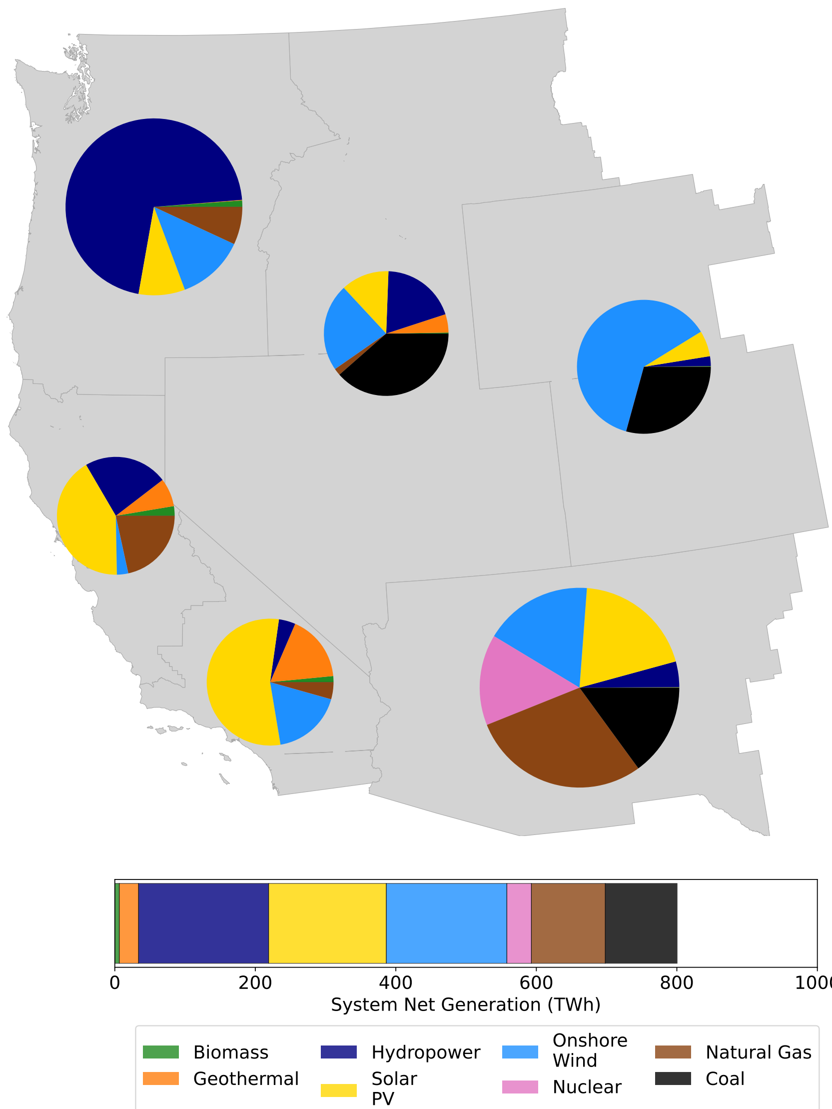
Supplementary Figure 5: System-level changes in installed generating capacity as a result of voluntary carbon-free electricity procurements, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions, showing outcomes for the full range of temporal matching targets.



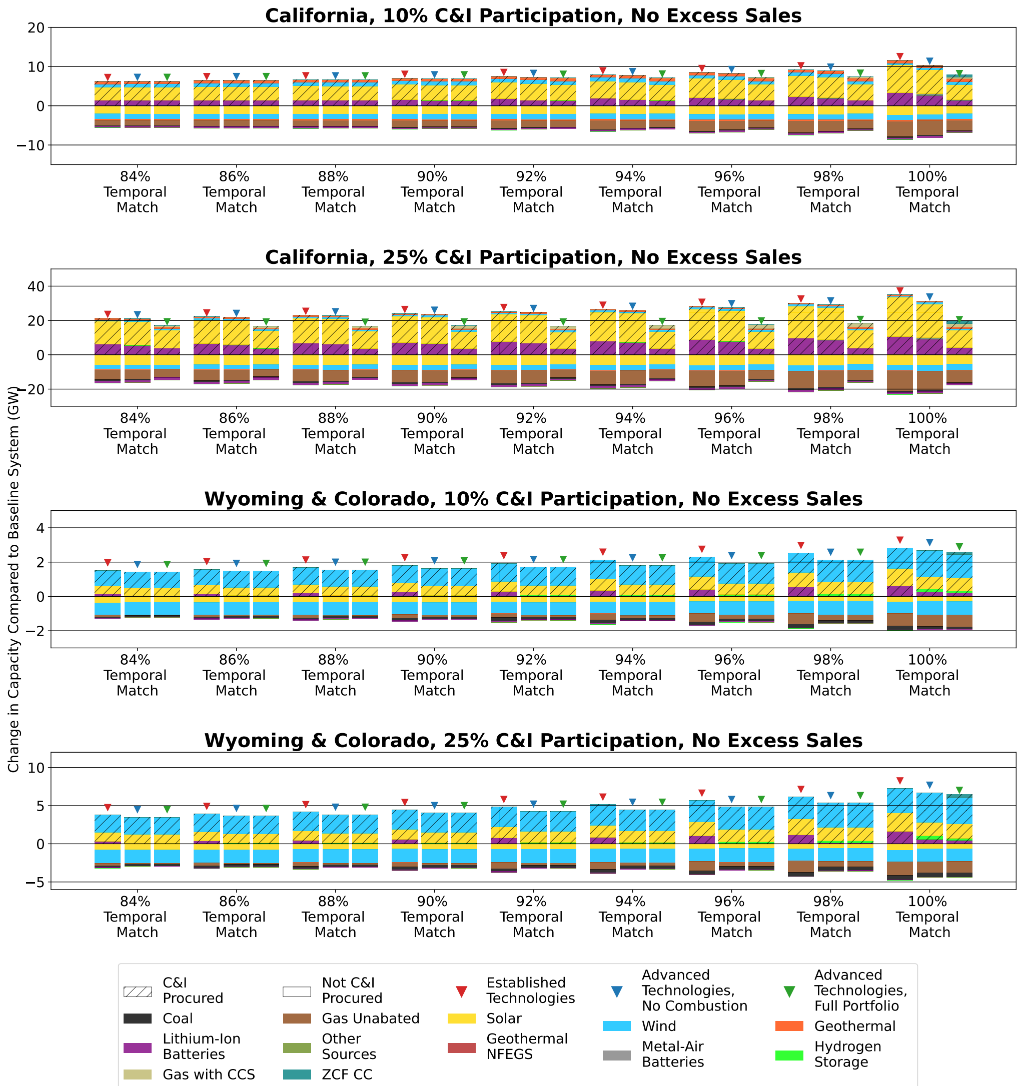
Supplementary Figure 6: Installed generating capacity in 2030 by technology and region in the baseline system.



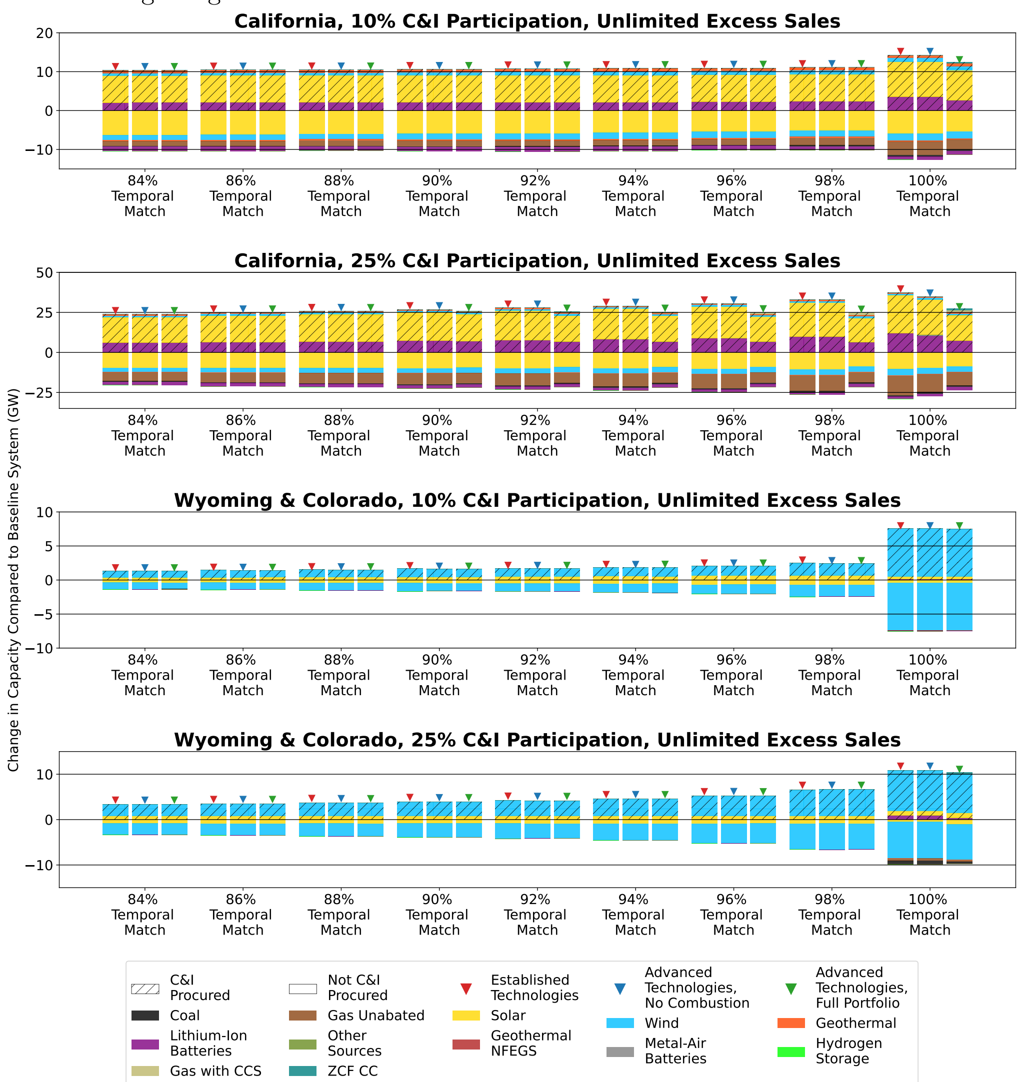
Supplementary Figure 7: Annual generation in 2030 by technology and region in the baseline system.



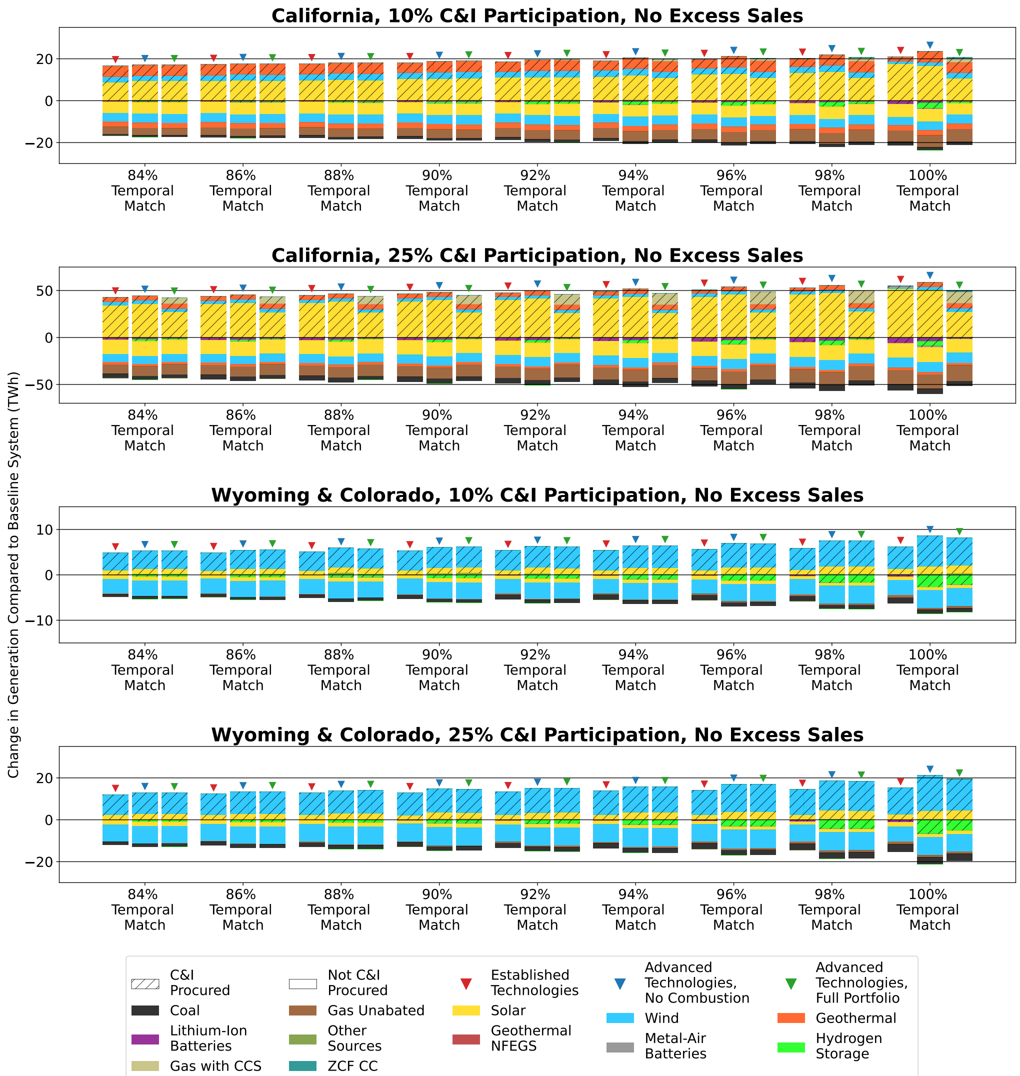
Supplementary Figure 8: System-level changes in installed generating capacity as a result of temporally-matched carbon-free electricity procurement with no excess sales permitted, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions.



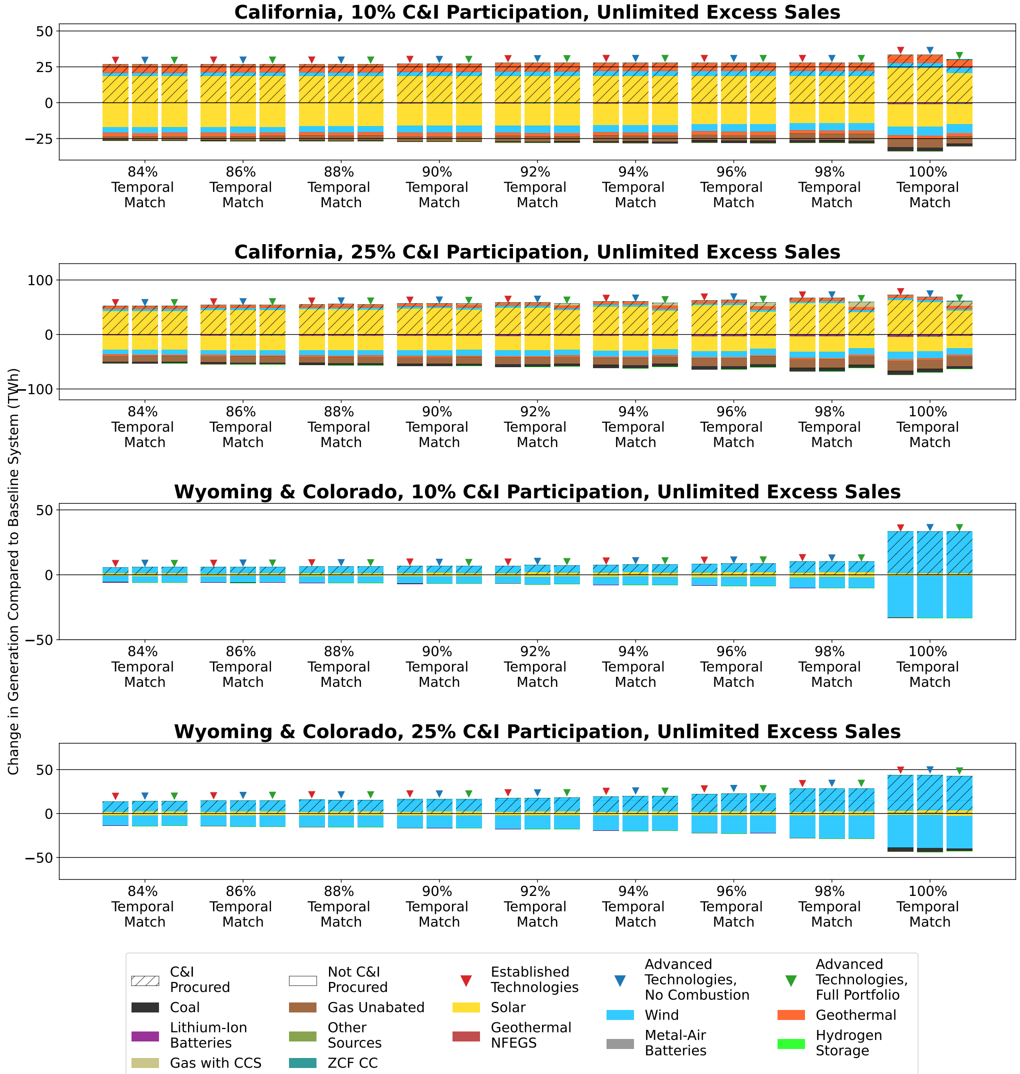
Supplementary Figure 9: System-level changes in installed generating capacity as a result of temporally-matched carbon-free electricity procurement with unlimited excess sales permitted, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions.



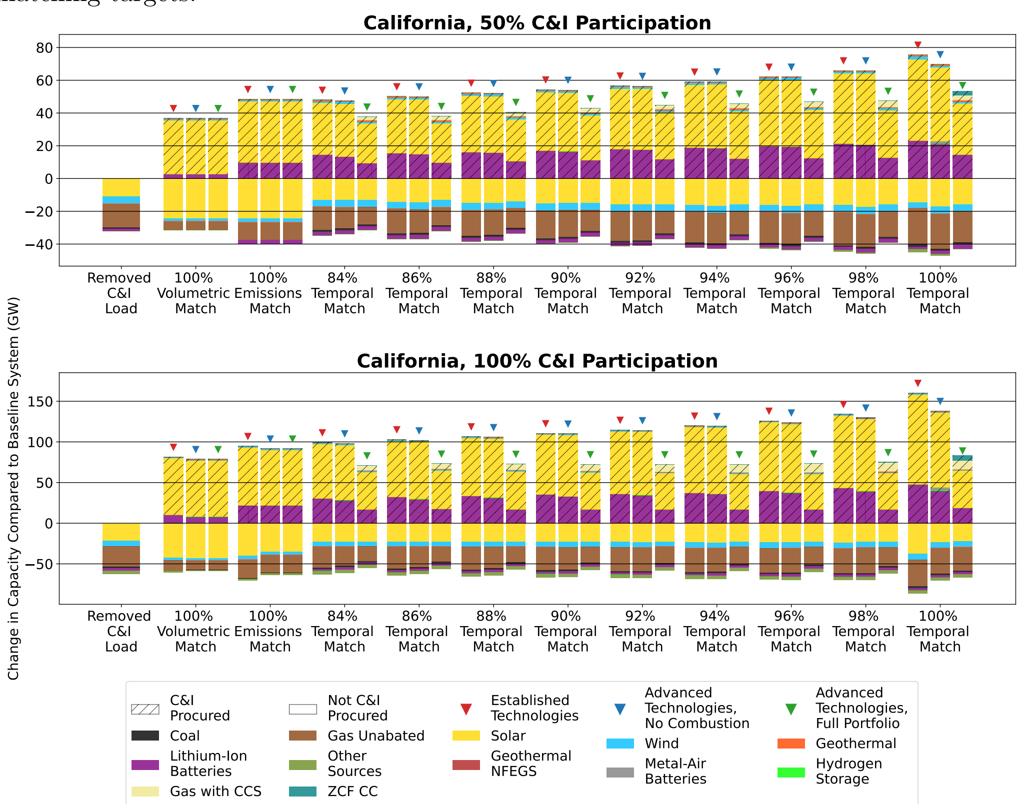
Supplementary Figure 10: System-level changes in generation as a result of temporally-matched carbon-free electricity procurement with no excess sales permitted, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions.



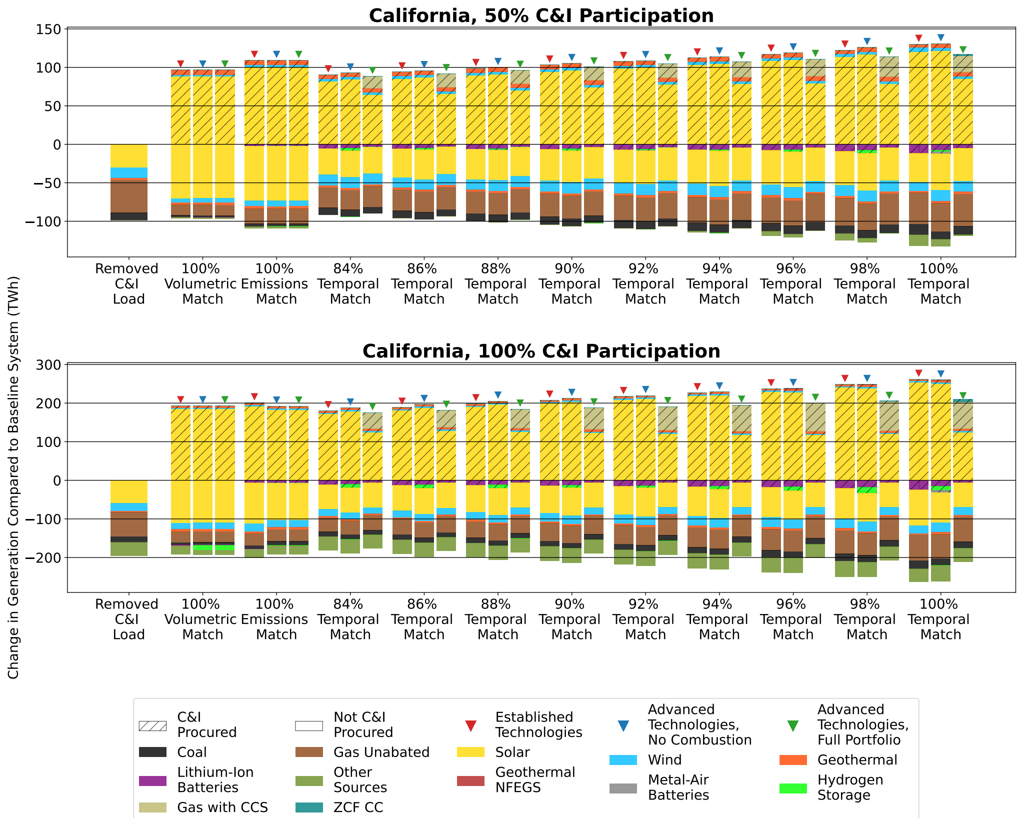
Supplementary Figure 11: System-level changes in generation as a result of temporally-matched carbon-free electricity procurement with unlimited excess sales permitted, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions.



Supplementary Figure 12: System-level changes in installed generating capacity as a result of voluntary carbon-free electricity procurements, for 50% and 100% C&I participation rates in the California target region, showing outcomes for the full range of temporal matching targets.

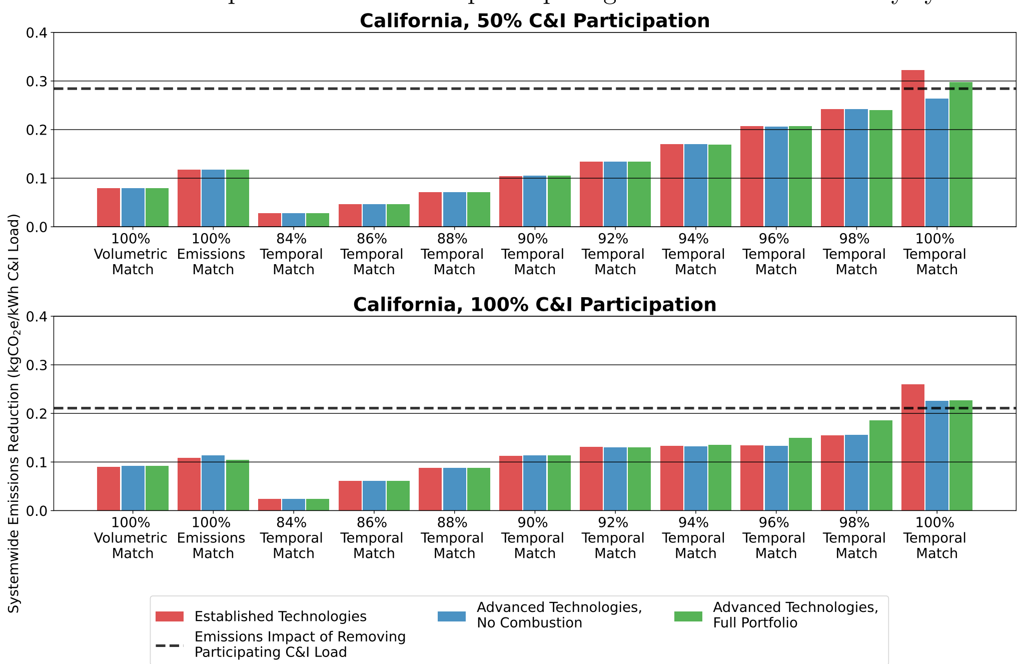


Supplementary Figure 13: System-level changes in generation as a result of voluntary carbon-free electricity procurements, for 50% and 100% C&I participation rates in the California target region, showing outcomes for the full range of temporal matching targets.



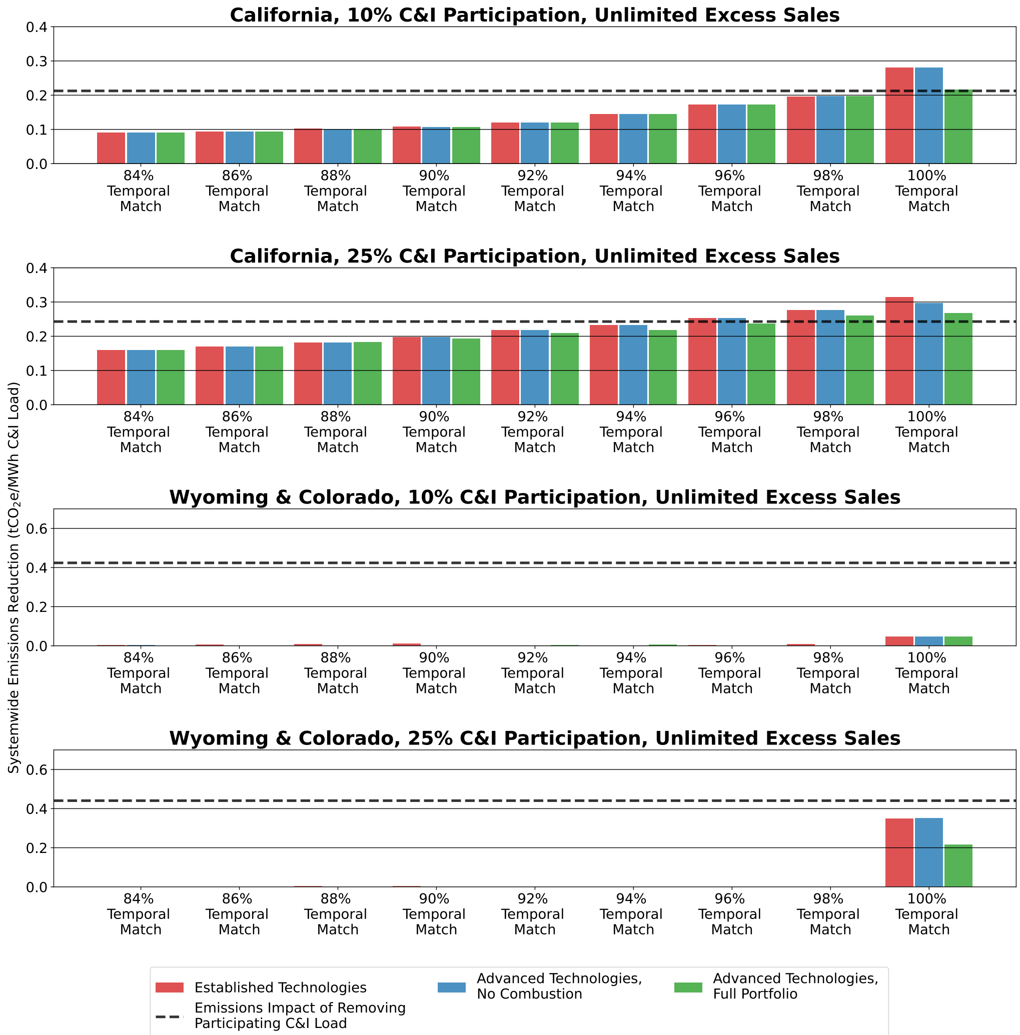
Supplementary Figure 14: System-level reductions in CO_2 emissions per MWh of C&I load participating in voluntary carbon-free electricity procurement, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions, showing outcomes for the full range of temporal matching targets. Dotted lines indicate the benchmark reduction rate associated with complete removal of the participating load from the electricity system.

Supplementary Figure 15: System-level reductions in CO_2 emissions per MWh of C&I load participating in voluntary carbon-free electricity procurement, for 50% and 100% C&I participation rates in the California target region, showing outcomes for the full range of temporal matching targets. Dotted lines indicate the benchmark reduction rate associated with complete removal of the participating load from the electricity system.

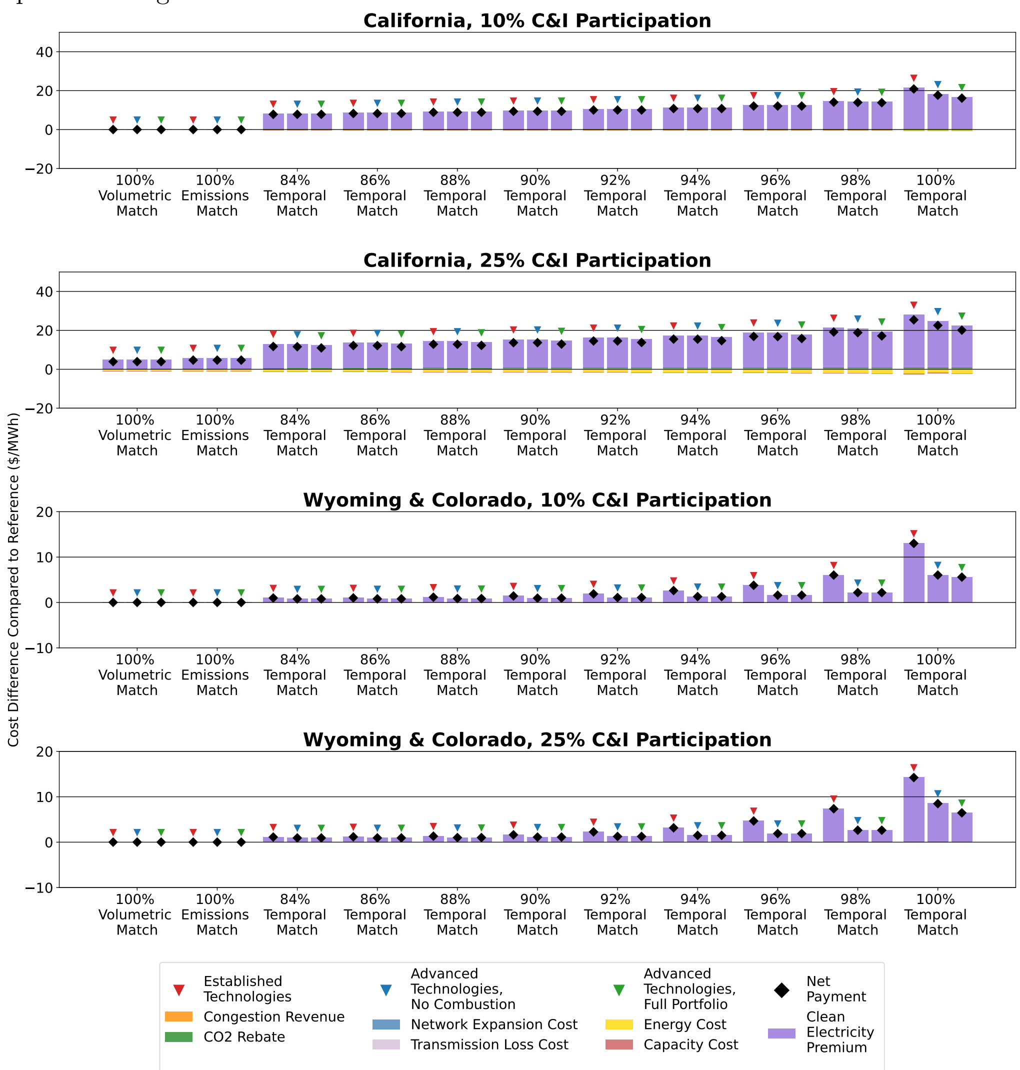


Supplementary Figure 16: System-level reductions in CO_2 emissions per MWh of C&I load participating in temporally matched carbon-free electricity procurement with no excess sales permitted, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions. Dotted lines indicate the benchmark reduction rate associated with complete removal of the participating load from the electricity system.

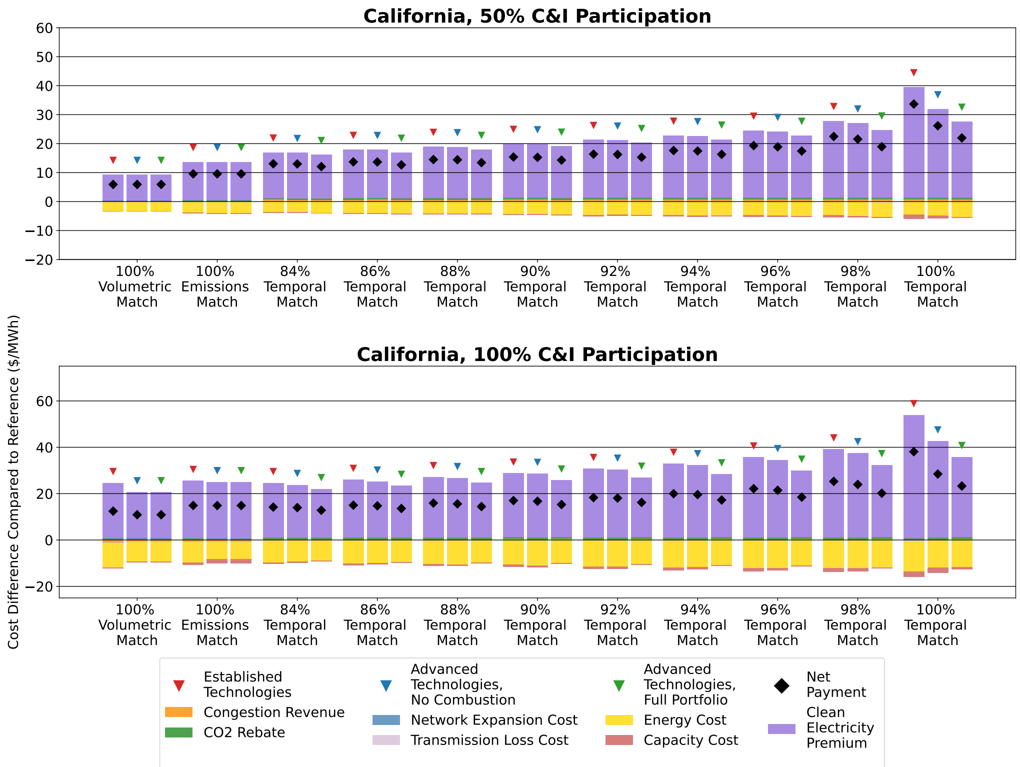
Supplementary Figure 17: System-level reductions in CO_2 emissions per MWh of C&I load participating in temporally matched carbon-free electricity procurement with unlimited excess sales permitted, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions. Dotted lines indicate the benchmark reduction rate associated with complete removal of the participating load from the electricity system.



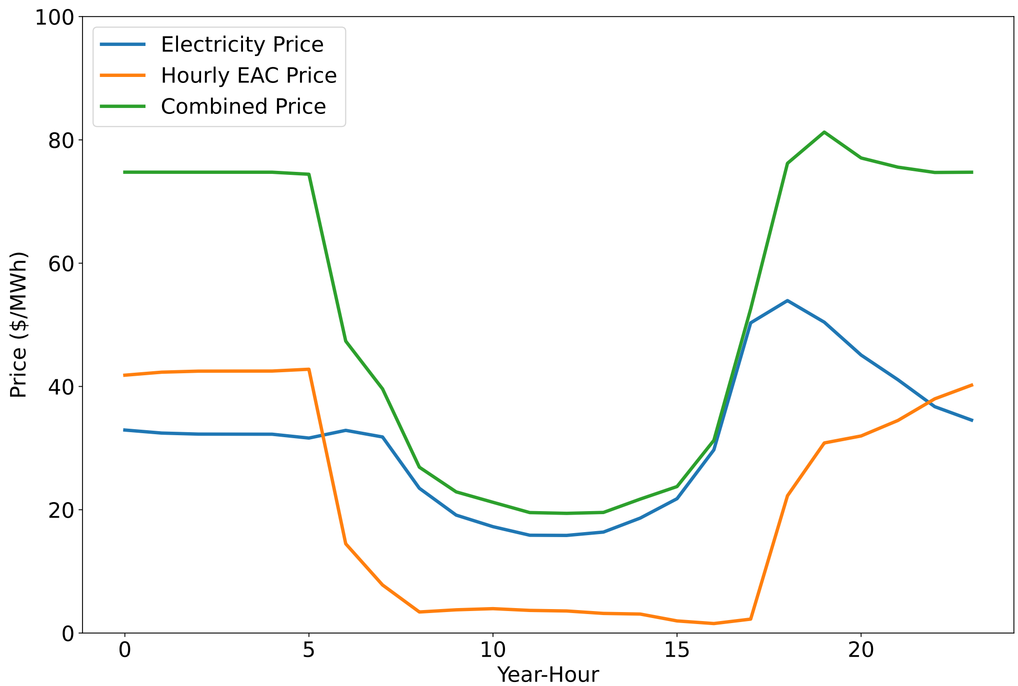
Supplementary Figure 18: The incremental cost of voluntary carbon-free electricity procurement for C&I participants in the California and Wyoming & Colorado target regions, for 10% and 25% participation rates, showing outcomes for the full range of temporal matching targets. Baseline prices in the reference case in each region are the same as reported in Figure 5 in the main text.



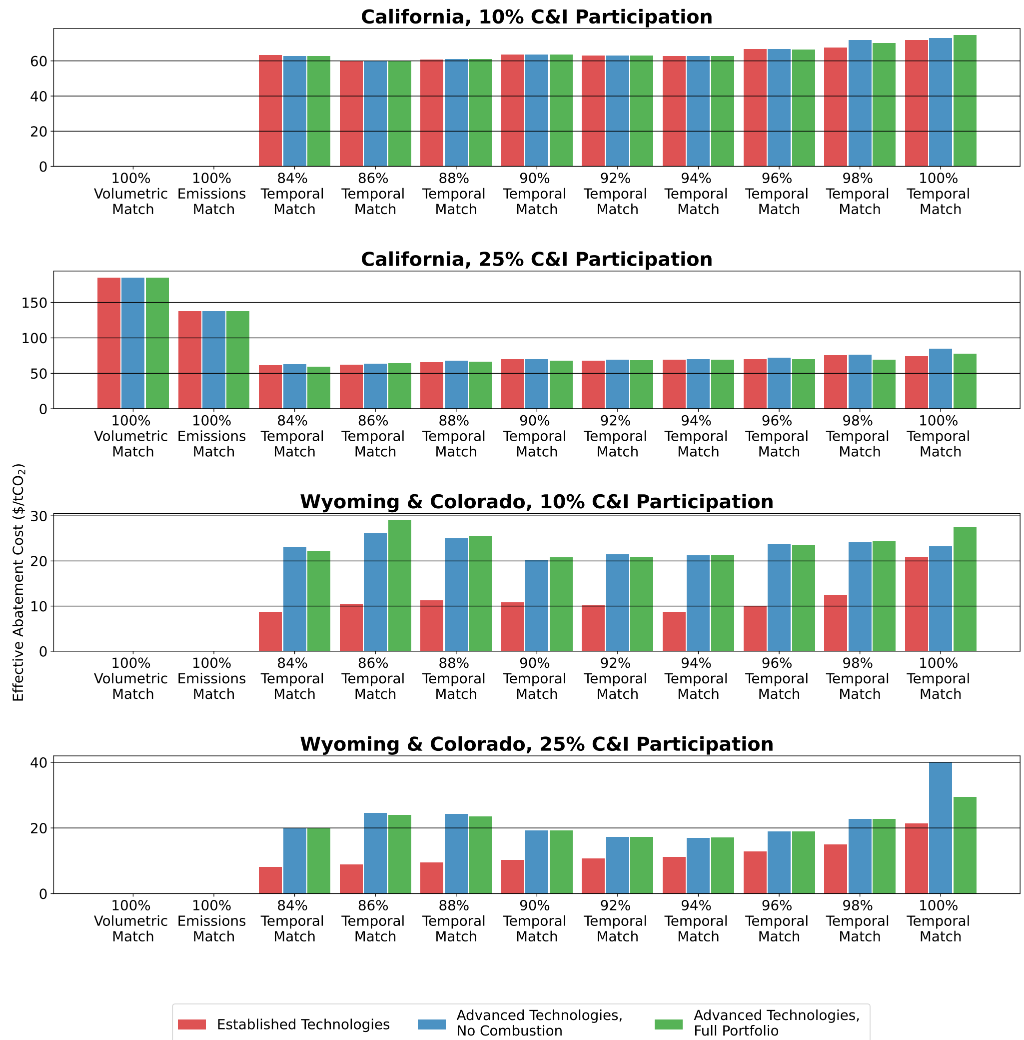
Supplementary Figure 19: The incremental cost of voluntary carbon-free electricity procurement for C&I participants in the California and Wyoming & Colorado target regions, for 50% and 100% participation rates, showing outcomes for the full range of temporal matching targets. Baseline prices in the reference case in each region are the same as reported in Figure 5 in the main text.



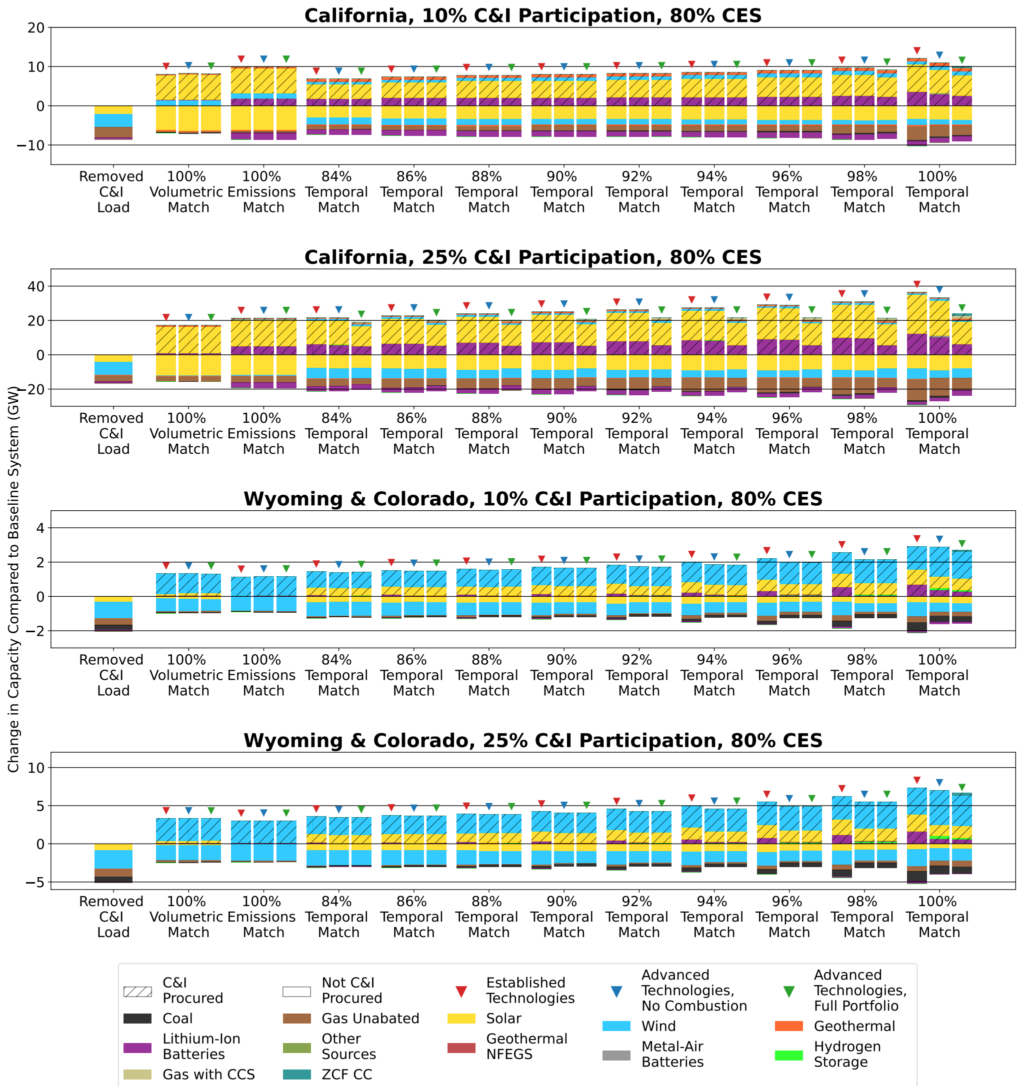
Supplementary Figure 20: Hourly grid electricity prices, EAC prices, and combined prices over an average day for C&I customers in California pursuing a 100% temporal matching target, with a 25% participation rate. While both grid electricity and EAC price profiles show declines during daytime hours, EAC prices are more consistently elevated during nighttime periods whereas electricity prices peak during the evening. The combined price remains high during nighttime periods, whereas grid prices peak during the evening and are significantly lower at night.



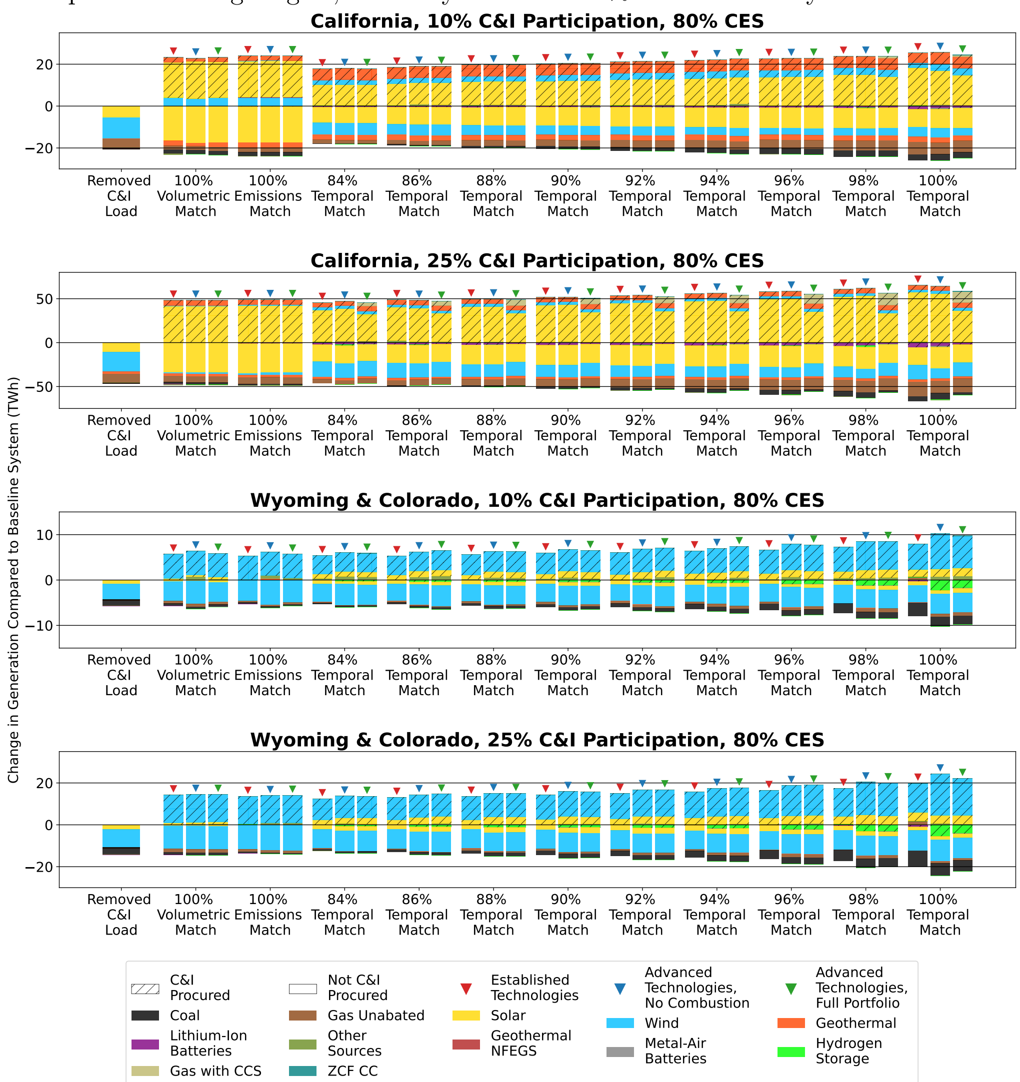
Supplementary Figure 21: Effective CO_2 abatement cost of voluntary carbon-free electricity procurement, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions, showing outcomes for the full range of temporal matching targets. Scenarios without data do not have zero abatement cost, but instead represent strategies driving no effective CO_2 abatement and incurring no cost premium over purely cost-optimized procurement.



Supplementary Figure 22: System-level changes in installed generating capacity as a result of voluntary carbon-free electricity procurements, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions, showing outcomes for the full range of temporal matching targets, with a system-wide 80% clean electricity standard.

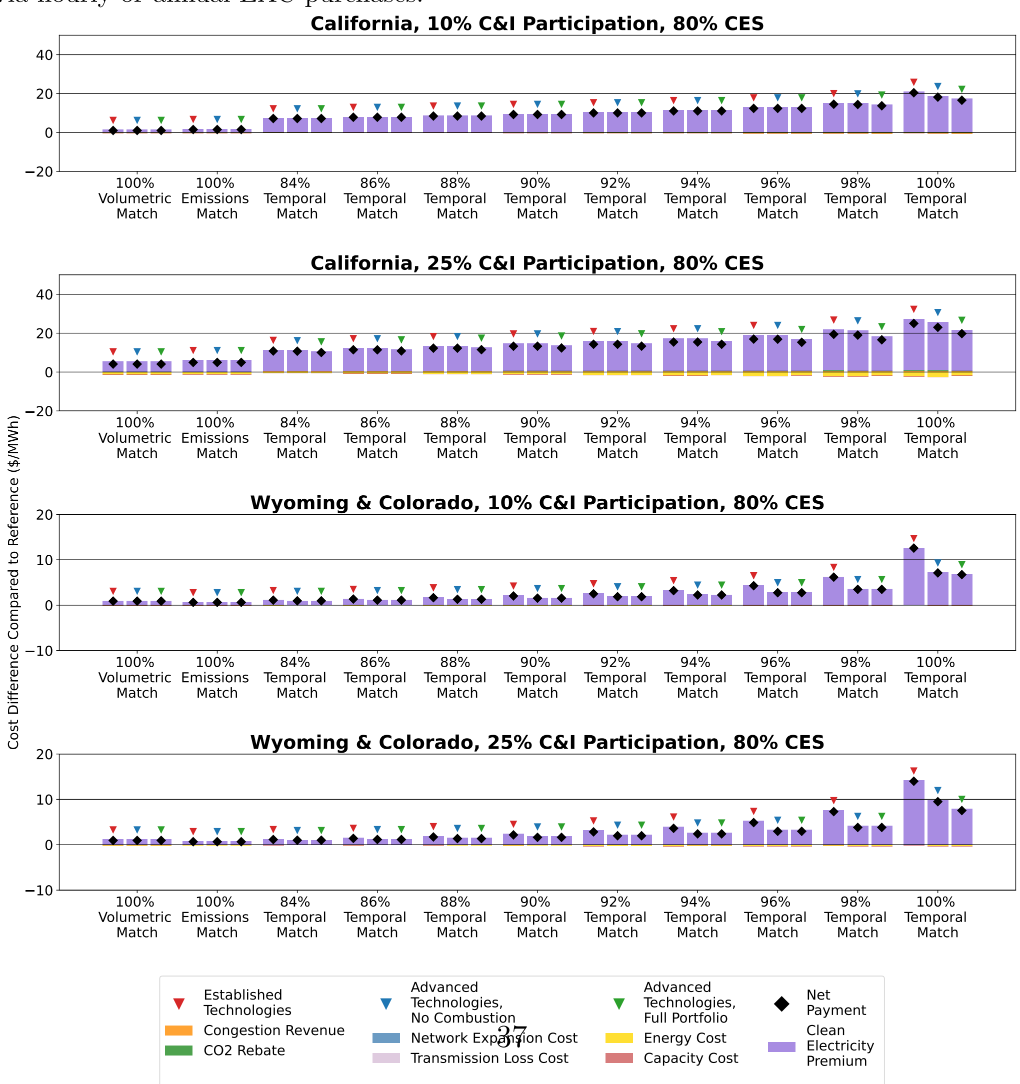


Supplementary Figure 23: System-level changes in generation as a result of voluntary carbon-free electricity procurements, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions, showing outcomes for the full range of temporal matching targets, with a system-wide 80% clean electricity standard.



Supplementary Figure 24: System-level reductions in CO_2 emissions per MWh of C&I load participating in voluntary carbon-free electricity procurement, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions, showing outcomes for the full range of temporal matching targets, with a system-wide 80% clean electricity standard. Dotted lines indicate the benchmark reduction rate associated with complete removal of the participating load from the electricity system.

Supplementary Figure 25: The incremental cost of voluntary carbon-free electricity procurement for C&I participants with a system-wide 80% clean electricity standard, broken down by category, showing outcomes for the full range of temporal matching targets. California participants' cost of electricity in the reference case is \$34.9/MWh, including a \$30.9/MWh energy payment, \$2.3/MWh capacity payment, -\$1.7/MWh congestion revenue (as negative cost), -\$0.6/MWh carbon dividend (as negative cost, assuming cap-and-trade revenue is reimbursed to consumers), \$3.4/MWh RPS/CES payment, $<$ \$0.1/MWh incremental transmission cost (excluding existing transmission cost as of 2021), and \$0.4/MWh transmission loss cost. Wyoming & Colorado participants' cost of electricity in the reference case is \$23.5/MWh, including a \$20.3/MWh energy payment, \$1.6/MWh capacity payment, -\$1.9/MWh congestion revenue, \$3.4/MWh RPS/CES payment, \$0/MWh incremental transmission cost, and \$0.2/MWh transmission loss cost. Reference costs do not include costs associated with distribution or existing transmission. The clean electricity premium reflects the additional payments made to procured generation via hourly or annual EAC purchases.



Supplementary Figure 26: Effective CO_2 abatement cost of voluntary carbon-free electricity procurement, for 10% and 25% C&I participation rates in the California and Wyoming & Colorado target regions, showing outcomes for the full range of temporal matching targets, with a system-wide 80% clean electricity standard.

Supplementary Table 7: Optimal capacity investments made under various voluntary carbon-free electricity procurement strategies, for central scenarios with 10% C&I participation in the California region. Power capacities are in units of GW, and energy capacities in units of GWh.

Matching Case	Technology Availability	Solar	Wind	Geothermal	Battery	Battery (Energy)	Metal-Air Storage	Metal-Air Storage (Energy)	Hydrogen Storage	Hydrogen Storage (Charge)	Hydrogen Storage (Energy)	CCS	ZCF
Temporal, 84%	Advanced	3.7	0.7	0.7	1.8	6.5	0.0	0.0	0.0	0.0	1.0	0.0	0.0
Temporal, 84%	Advanced, no CCS/ZCF	3.7	0.7	0.7	1.8	6.5	0.0	0.0	0.0	0.0	1.0	0.0	0.0
Temporal, 84%	Established	3.6	0.7	0.7	1.8	6.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 86%	Advanced	3.8	0.7	0.7	2.0	7.3	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Temporal, 86%	Advanced, no CCS/ZCF	3.8	0.7	0.7	2.0	7.3	0.0	0.0	0.0	0.0	0.2	0.0	0.0
Temporal, 86%	Established	3.8	0.7	0.7	2.0	7.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 88%	Advanced	4.2	0.7	0.7	2.1	8.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 88%	Advanced, no CCS/ZCF	4.2	0.7	0.7	2.1	8.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 88%	Established	4.2	0.7	0.7	2.1	8.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 90%	Advanced	4.3	0.8	0.7	2.1	8.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 90%	Advanced, no CCS/ZCF	4.3	0.8	0.7	2.1	8.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 90%	Established	4.3	0.8	0.7	2.1	8.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 92%	Advanced	4.6	0.9	0.7	2.1	9.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 92%	Advanced, no CCS/ZCF	4.6	0.9	0.7	2.1	9.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 92%	Established	4.6	0.9	0.7	2.1	9.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 94%	Advanced	4.7	1.0	0.7	2.2	9.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 94%	Advanced, no CCS/ZCF	4.7	1.0	0.7	2.2	9.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 94%	Established	4.7	1.0	0.7	2.2	9.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 96%	Advanced	5.0	1.0	0.7	2.3	11.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 96%	Advanced, no CCS/ZCF	5.0	1.0	0.7	2.3	11.3	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Temporal, 96%	Established	5.0	1.0	0.7	2.3	11.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 98%	Advanced	5.4	1.0	0.7	2.4	12.4	0.0	0.0	0.0	0.1	10.5	0.0	0.0
Temporal, 98%	Advanced, no CCS/ZCF	5.4	1.0	0.7	2.4	12.7	0.0	0.0	0.0	0.1	11.1	0.0	0.0
Temporal, 98%	Established	5.5	1.0	0.7	2.5	13.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 100%	Advanced	5.5	1.0	0.7	2.6	13.6	0.0	0.0	0.0	0.0	0.7	0.0	0.5
Temporal, 100%	Advanced, no CCS/ZCF	5.9	1.0	0.7	2.9	16.1	0.3	41.5	0.0	0.0	5.3	0.0	0.0
Temporal, 100%	Established	7.0	0.7	0.7	3.6	20.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions, 100%	Advanced	6.8	0.0	0.3	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions, 100%	Advanced, no CCS/ZCF	6.8	0.0	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions, 100%	Established	6.9	0.0	0.3	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Volumetric, 100%	Advanced	6.3	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Volumetric, 100%	Advanced, no CCS/ZCF	6.3	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Volumetric, 100%	Established	6.2	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Supplementary Table 8: Optimal capacity investments made under various voluntary carbon-free electricity procurement strategies, for central scenarios with 25% C&I participation in the California region. Power capacities are in units of GW, and energy capacities in units of GWh.

Matching Case	Technology Availability	Solar	Wind	Geothermal	Battery	Battery (Energy)	Metal-Air Storage	Metal-Air Storage (Energy)	Hydrogen Storage	Hydrogen Storage (Charge)	Hydrogen Storage (Energy)	CCS	ZCF
Temporal, 84%	Advanced	11.6	1.0	0.7	4.8	23.7	0.0	0.0	0.0	0.1	7.2	0.7	0.0
Temporal, 84%	Advanced, no CCS/ZCF	14.2	1.0	0.7	5.7	30.2	0.0	0.0	0.1	0.7	46.7	0.0	0.0
Temporal, 84%	Established	13.9	1.0	0.7	6.1	33.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 86%	Advanced	12.3	1.0	0.7	5.3	26.3	0.0	0.0	0.0	0.0	0.0	0.7	0.0
Temporal, 86%	Advanced, no CCS/ZCF	14.7	1.0	0.7	6.3	34.1	0.0	0.0	0.0	0.4	24.2	0.0	0.0
Temporal, 86%	Established	14.5	1.0	0.7	6.5	35.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 88%	Advanced	12.6	1.0	0.7	5.4	26.6	0.0	0.0	0.0	0.0	0.0	0.8	0.0
Temporal, 88%	Advanced, no CCS/ZCF	15.4	1.0	0.7	6.8	37.5	0.0	0.0	0.0	0.1	9.2	0.0	0.0
Temporal, 88%	Established	15.3	1.0	0.7	6.9	38.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 90%	Advanced	12.7	1.0	0.7	5.5	27.7	0.0	0.0	0.0	0.0	0.0	0.9	0.0
Temporal, 90%	Advanced, no CCS/ZCF	15.9	1.0	0.7	7.3	40.7	0.0	0.0	0.0	0.0	2.4	0.0	0.0
Temporal, 90%	Established	15.9	1.0	0.7	7.3	40.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 92%	Advanced	13.4	1.0	0.7	5.7	29.7	0.0	0.0	0.0	0.0	0.0	1.0	0.0
Temporal, 92%	Advanced, no CCS/ZCF	16.6	1.0	0.7	7.7	43.0	0.0	0.0	0.0	0.2	10.9	0.0	0.0
Temporal, 92%	Established	16.5	1.0	0.7	7.8	43.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 94%	Advanced	13.9	1.0	0.7	5.9	31.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0
Temporal, 94%	Advanced, no CCS/ZCF	17.4	1.0	0.7	8.2	45.9	0.0	0.0	0.0	0.2	16.3	0.0	0.0
Temporal, 94%	Established	17.3	1.0	0.7	8.3	46.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 96%	Advanced	14.5	1.0	0.7	6.3	33.4	0.0	0.0	0.0	0.0	0.0	1.2	0.0
Temporal, 96%	Advanced, no CCS/ZCF	18.3	1.0	0.7	8.8	49.7	0.0	0.0	0.0	0.2	18.8	0.0	0.0
Temporal, 96%	Established	18.3	1.0	0.7	8.9	50.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 98%	Advanced	14.2	1.0	0.7	6.2	33.0	0.0	0.0	0.0	0.0	0.0	1.5	0.0
Temporal, 98%	Advanced, no CCS/ZCF	19.5	1.0	0.7	9.4	53.5	0.0	0.0	0.1	0.5	59.1	0.0	0.0
Temporal, 98%	Established	19.3	1.0	0.7	9.9	56.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 100%	Advanced	15.5	1.0	0.7	7.1	39.0	0.0	0.0	0.0	0.0	0.0	1.3	1.1
Temporal, 100%	Advanced, no CCS/ZCF	20.5	1.0	0.7	10.3	60.2	0.7	109.9	0.0	0.1	17.4	0.0	0.0
Temporal, 100%	Established	22.7	0.9	0.7	12.1	70.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions, 100%	Advanced	16.8	0.2	0.7	3.9	5.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions, 100%	Advanced, no CCS/ZCF	16.8	0.2	0.7	3.9	5.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions, 100%	Established	16.8	0.2	0.7	3.9	5.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Volumetric, 100%	Advanced	16.7	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Volumetric, 100%	Advanced, no CCS/ZCF	16.7	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Volumetric, 100%	Established	16.7	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Supplementary Table 9: Optimal capacity investments made under various voluntary carbon-free electricity procurement strategies, for central scenarios with 10% C&I participation in the Wyoming & Colorado region. Power capacities are in units of GW, and energy capacities in units of GWh.

Matching Case	Technology Availability	Solar	Wind	Geothermal	Battery	Battery (Energy)	Metal-Air Storage	Metal-Air Storage (Energy)	Hydrogen Storage	Hydrogen Storage (Charge)	Hydrogen Storage (Energy)	CCS	ZCF
Temporal, 84%	Advanced	0.4	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.1	4.3	0.0	0.0
Temporal, 84%	Advanced, no CCS/ZCF	0.4	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.1	4.4	0.0	0.0
Temporal, 84%	Established	0.5	0.9	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 86%	Advanced	0.5	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	6.3	0.0	0.0
Temporal, 86%	Advanced, no CCS/ZCF	0.5	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	6.2	0.0	0.0
Temporal, 86%	Established	0.5	1.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 88%	Advanced	0.5	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	8.8	0.0	0.0
Temporal, 88%	Advanced, no CCS/ZCF	0.5	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	8.8	0.0	0.0
Temporal, 88%	Established	0.5	1.0	0.0	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 90%	Advanced	0.5	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	12.7	0.0	0.0
Temporal, 90%	Advanced, no CCS/ZCF	0.5	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	12.6	0.0	0.0
Temporal, 90%	Established	0.5	1.1	0.0	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 92%	Advanced	0.5	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.2	15.4	0.0	0.0
Temporal, 92%	Advanced, no CCS/ZCF	0.5	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.2	15.4	0.0	0.0
Temporal, 92%	Established	0.6	1.1	0.0	0.2	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 94%	Advanced	0.6	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.2	18.7	0.0	0.0
Temporal, 94%	Advanced, no CCS/ZCF	0.6	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.2	18.6	0.0	0.0
Temporal, 94%	Established	0.6	1.1	0.0	0.3	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 96%	Advanced	0.6	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.2	23.8	0.0	0.0
Temporal, 96%	Advanced, no CCS/ZCF	0.6	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.2	23.9	0.0	0.0
Temporal, 96%	Established	0.7	1.2	0.0	0.4	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 98%	Advanced	0.6	1.4	0.0	0.0	0.0	0.0	0.0	0.1	0.3	32.3	0.0	0.0
Temporal, 98%	Advanced, no CCS/ZCF	0.6	1.4	0.0	0.0	0.0	0.0	0.0	0.1	0.3	32.3	0.0	0.0
Temporal, 98%	Established	0.8	1.2	0.0	0.6	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 100%	Advanced	0.6	1.6	0.0	0.3	0.4	0.0	0.0	0.1	0.4	47.3	0.0	0.1
Temporal, 100%	Advanced, no CCS/ZCF	0.6	1.8	0.0	0.4	0.6	0.0	0.0	0.1	0.6	62.7	0.0	0.0
Temporal, 100%	Established	0.9	1.3	0.0	0.7	3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions, 100%	Advanced	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions, 100%	Advanced, no CCS/ZCF	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions, 100%	Established	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Volumetric, 100%	Advanced	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Volumetric, 100%	Advanced, no CCS/ZCF	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Volumetric, 100%	Established	0.2	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Supplementary Table 10: Optimal capacity investments made under various voluntary carbon-free electricity procurement strategies, for central scenarios with 25% C&I participation in the Wyoming & Colorado region. Power capacities are in units of GW, and energy capacities in units of GWh.

Matching Case	Technology Availability	Solar	Wind	Geothermal	Battery	Battery (Energy)	Metal-Air Storage	Metal-Air Storage (Energy)	Hydrogen Storage	Hydrogen Storage (Charge)	Hydrogen Storage (Energy)	CCS	ZCF
Temporal, 84%	Advanced	1.1	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.1	11.9	0.0	0.0
Temporal, 84%	Advanced, no CCS/ZCF	1.1	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.1	11.9	0.0	0.0
Temporal, 84%	Established	1.1	2.3	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 86%	Advanced	1.1	2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.2	15.3	0.0	0.0
Temporal, 86%	Advanced, no CCS/ZCF	1.1	2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.2	15.4	0.0	0.0
Temporal, 86%	Established	1.1	2.4	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 88%	Advanced	1.1	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.2	21.1	0.0	0.0
Temporal, 88%	Advanced, no CCS/ZCF	1.1	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.2	21.1	0.0	0.0
Temporal, 88%	Established	1.2	2.5	0.0	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 90%	Advanced	1.2	2.6	0.0	0.0	0.0	0.0	0.0	0.1	0.3	30.7	0.0	0.0
Temporal, 90%	Advanced, no CCS/ZCF	1.2	2.6	0.0	0.0	0.0	0.0	0.0	0.1	0.3	30.7	0.0	0.0
Temporal, 90%	Established	1.2	2.6	0.0	0.4	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 92%	Advanced	1.3	2.8	0.0	0.0	0.0	0.0	0.0	0.1	0.4	38.0	0.0	0.0
Temporal, 92%	Advanced, no CCS/ZCF	1.3	2.8	0.0	0.0	0.0	0.0	0.0	0.1	0.4	38.1	0.0	0.0
Temporal, 92%	Established	1.4	2.7	0.0	0.5	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 94%	Advanced	1.3	2.9	0.0	0.0	0.0	0.0	0.0	0.1	0.5	45.6	0.0	0.0
Temporal, 94%	Advanced, no CCS/ZCF	1.3	2.9	0.0	0.0	0.0	0.0	0.0	0.1	0.5	45.7	0.0	0.0
Temporal, 94%	Established	1.5	2.8	0.0	0.8	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 96%	Advanced	1.4	3.2	0.0	0.0	0.0	0.0	0.0	0.1	0.6	58.9	0.0	0.0
Temporal, 96%	Advanced, no CCS/ZCF	1.4	3.2	0.0	0.0	0.0	0.0	0.0	0.1	0.6	58.8	0.0	0.0
Temporal, 96%	Established	1.8	2.9	0.0	1.0	2.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 98%	Advanced	1.6	3.5	0.0	0.1	0.1	0.0	0.0	0.2	0.8	81.8	0.0	0.0
Temporal, 98%	Advanced, no CCS/ZCF	1.6	3.5	0.0	0.1	0.1	0.0	0.0	0.2	0.8	81.8	0.0	0.0
Temporal, 98%	Established	2.0	2.9	0.0	1.4	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temporal, 100%	Advanced	1.5	4.1	0.0	0.5	1.1	0.0	0.0	0.2	1.0	112.5	0.0	0.3
Temporal, 100%	Advanced, no CCS/ZCF	1.3	4.7	0.0	0.6	1.5	0.0	0.0	0.4	1.3	187.1	0.0	0.0
Temporal, 100%	Established	2.4	3.3	0.0	1.6	9.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions, 100%	Advanced	0.0	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions, 100%	Advanced, no CCS/ZCF	0.1	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Emissions, 100%	Established	0.0	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Volumetric, 100%	Advanced	0.4	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Volumetric, 100%	Advanced, no CCS/ZCF	0.4	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Volumetric, 100%	Established	0.3	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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