Paths to Carbon Neutrality

A Comparison of Strategies for Tackling Corporate Scope II Carbon Emissions

APPENDIX

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APPENDIX A: Methodology and Input Data

A.1: Model Overview

A.1.1: Procurement Strategies

This analysis was undertaken from the perspective of a corporation with significant electricity demand voluntarily procuring renewable energy in order to "offset" the impact of their demand on the electric grid. The purpose of the analysis is to compare strategies for voluntary renewable procurement in terms of cost and carbon displacement. Four different strategies for renewable procurement were analyzed:

1. **Annual energy matching** (industry standard): annual energy matching is the current industry standard strategy for Scope 2[1] CO_2 emissions reduction. Using this strategy, a customer procures clean energy assets such that the annual generation from these assets matches the customer's annual electricity consumption. This strategy does not restrict clean energy procurement location within the bounds of this study (U.S. power markets). For example, a customer could offset their load in New York with energy generated by a wind farm in Texas. Because this analysis is confined to the U.S., this strategy matches the commitment of the RE100 initiative (which treats the U.S. and Canada as a single "market").
2. **Local annual energy matching**: local annual energy matching is a location-constrained version of annual energy matching. Power grid emission rates vary by location, so annual energy matching does not guarantee a net-zero carbon footprint when emission rates are higher at the load location than the generation location. To address this concern, using this strategy the customer locates clean energy assets in the same power system balancing authority as their load. Like annual energy matching, this strategy matches annual electricity load with annual clean energy output.
3. **Hourly energy matching**: the hourly matching strategy is bound by both locational and temporal constraints. To achieve hourly energy matching, the customer must match their electricity consumption with clean energy on an hourly basis in the same balancing authority. In addition, the customer can procure battery storage to shift clean energy between hours. This is the commitment made by Google and others.
4. **Carbon matching**: carbon matching is an alternative approach to Scope 2 CO_2 emissions reduction. Rather than attempting to match energy in terms of megawatt-hours (MWh), this strategy addresses carbon emissions directly. Using this strategy, CO_2 emissions are accounted for directly using the hourly locational marginal emissions rate at the customer's load and clean energy generation locations. A customer would procure clean energy assets such that the generation from these assets displaces a quantity of carbon emissions equal to or greater than the emissions generated by the customer's electricity consumption.

It is important to note that for the annual energy matching strategies (annual energy matching and local annual energy matching), the customer load shape is inconsequential – the only metric that matters is total annual load. For the 24x7 energy matching strategy, the load shape is relevant because the customer must match their load with clean energy generation in every hour. For the carbon matching strategy, the

1 According to the EPA, Scope 2 emissions are "indirect GHG emissions associated with the purchase of electricity, steam, heat, or cooling."

load shape is relevant because LMER varies temporally, so load in one hour may have a different carbon footprint than load in another hour.

Table 1 summarizes the strategies and procurement types in this analysis.

Table 1: Summary of Corporate Procurement Targets in Analysis

Strategy	Matching Metric	Matching Time Frame	Geographic Boundary For Procurement
Annual Energy Matching (industry standard)	Energy	Annual	Same balancing authority as load + MISO, PJM, ERCOT, SPP, CAISO
Local Annual Energy Matching	Energy	Annual	Same balancing authority as load
Hourly energy matching	Energy	Hourly	Same balancing authority as load
Carbon Matching	Carbon	Annual	Same balancing authority as load + MISO, PJM, ERCOT, SPP, CAISO

A.1.2: Balancing Authorities and Energy Areas

All four strategies were evaluated for two customer types in five different balancing authorities:

- CAISO – California Independent System Operator
- DUKE – Duke Energy Carolinas
- LADWP – Los Angeles Department of Water and Power
- PGE – Portland General Electric
- PJM – PJM Interconnection

These balancing authorities vary in their size and regulatory structure. PJM and CAISO are large electric system operators with several member utilities, 10's of millions of customers, and large geographical extents. Each operates a large wholesale energy market with competitive price formation for energy and capacity.

DUKE is a regional vertically integrated electric utility (VIEU) serving portions of North Carolina, South Carolina, and Tennessee. LADWP and PGE are vertically integrated utilities based in a single metropolitan area. Unlike CAISO and PJM, these balancing authorities do not operate wholesale markets and do not have competitive price formation.

In addition, for the U.S.-wide procurement geography, renewable energy could be procured in three additional ISO/RTO balancing authorities:

- ERCOT – Electric Reliability Council of Texas
- SPP – Southwest Power Pool
- MISO – Midcontinent System Operator

All five ISO/RTO balancing authorities are segmented into constituent 'energy areas', which are zones for which TCR has zonal Location Marginal Price (LMP) and Marginal Emission Rate (MER) forecasts. For the most part, each energy area represents a single member utility. DUKE, LADWP, and PGE each just contain a single energy area.

Figure 1, Figure 2, and Figure 3 show the geographic extent of the five analyzed balancing authorities. Figure 4, Figure 5, and Figure 6 show the geographic extent of the additional ISO/RTO regions where clean energy was available for procurement (ERCOT, MISO, and SPP). Table 17 (in Appendix B) provides a list of energy areas in each balancing authority.

Figure 1: Map of PGE, LADWP, and CAISO. CAISO is split into its member utilities, listed as 'Energy Areas'[2]

[2] Image courtesy of S&P Global

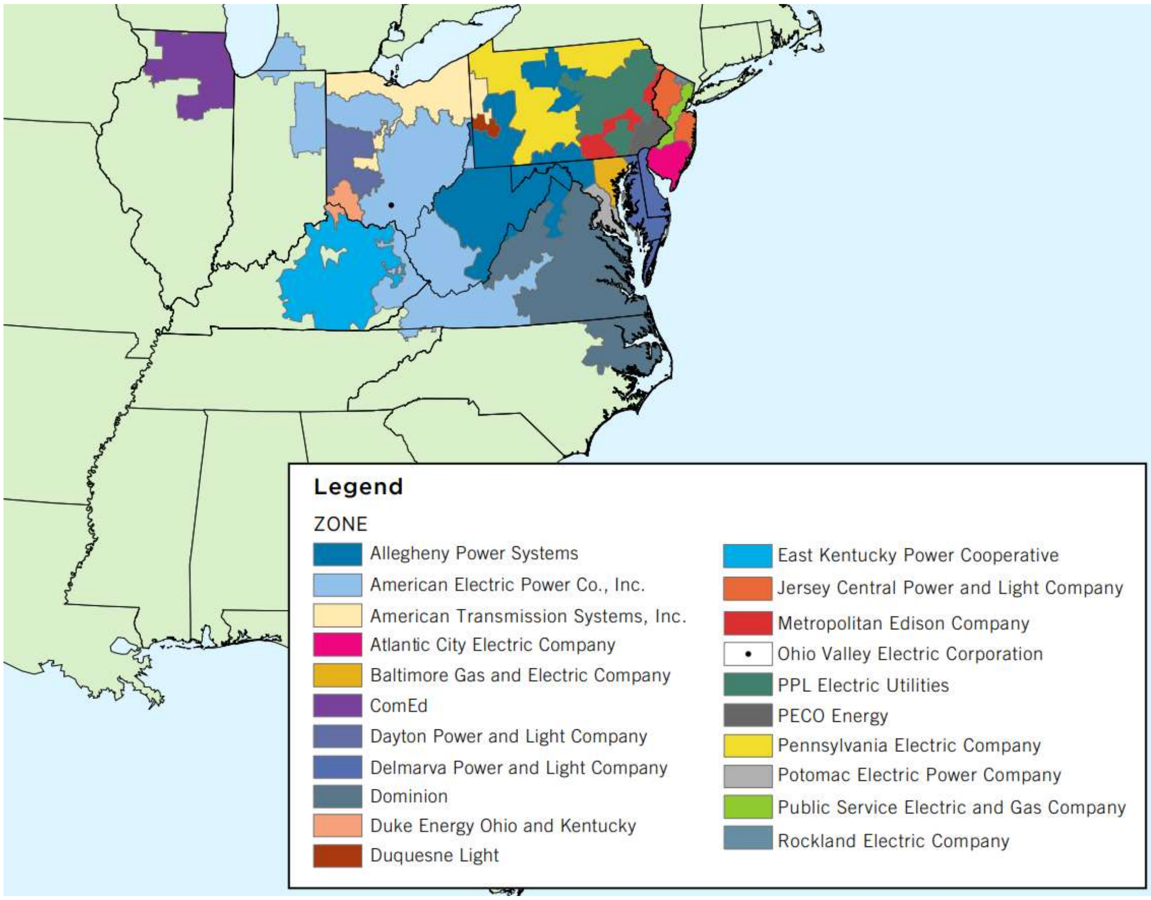


Figure 2: Map of PJM with Energy Area (Zone) Legend[3]

[3] Image courtesy of S&P Global

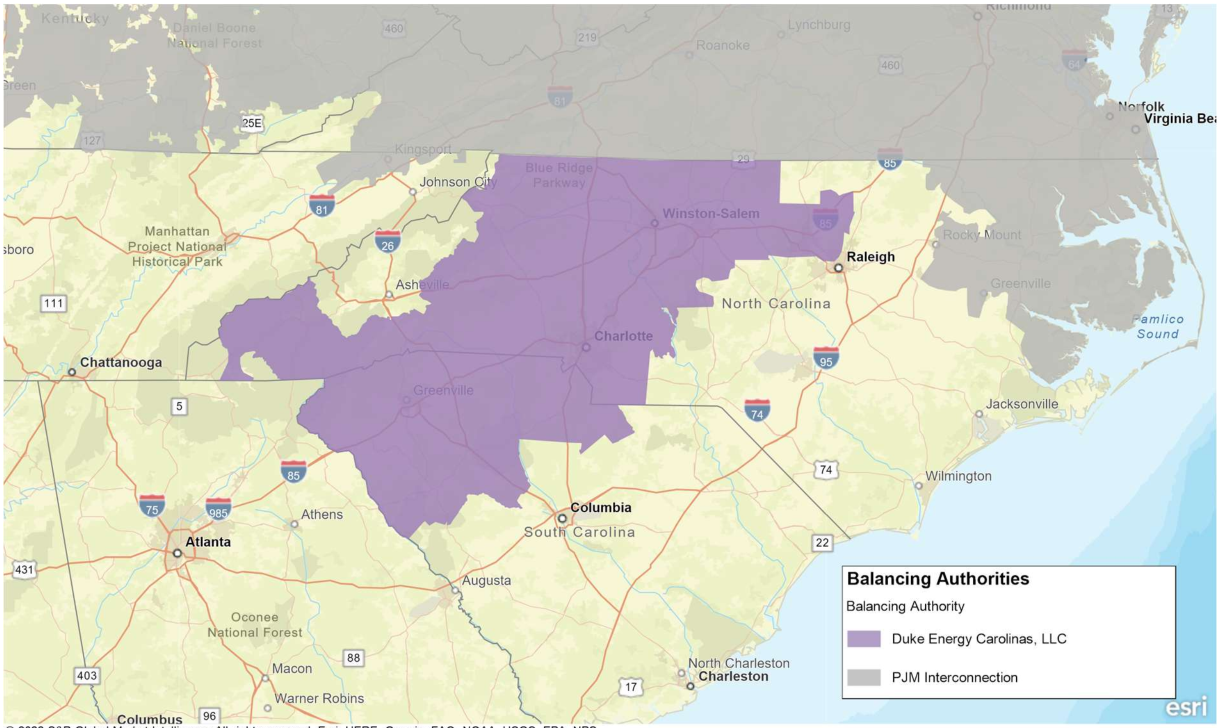


Figure 3: Map of Duke Energy Carolinas (PJM shown for comparison)[4]

[4] Image courtesy of S&P Global

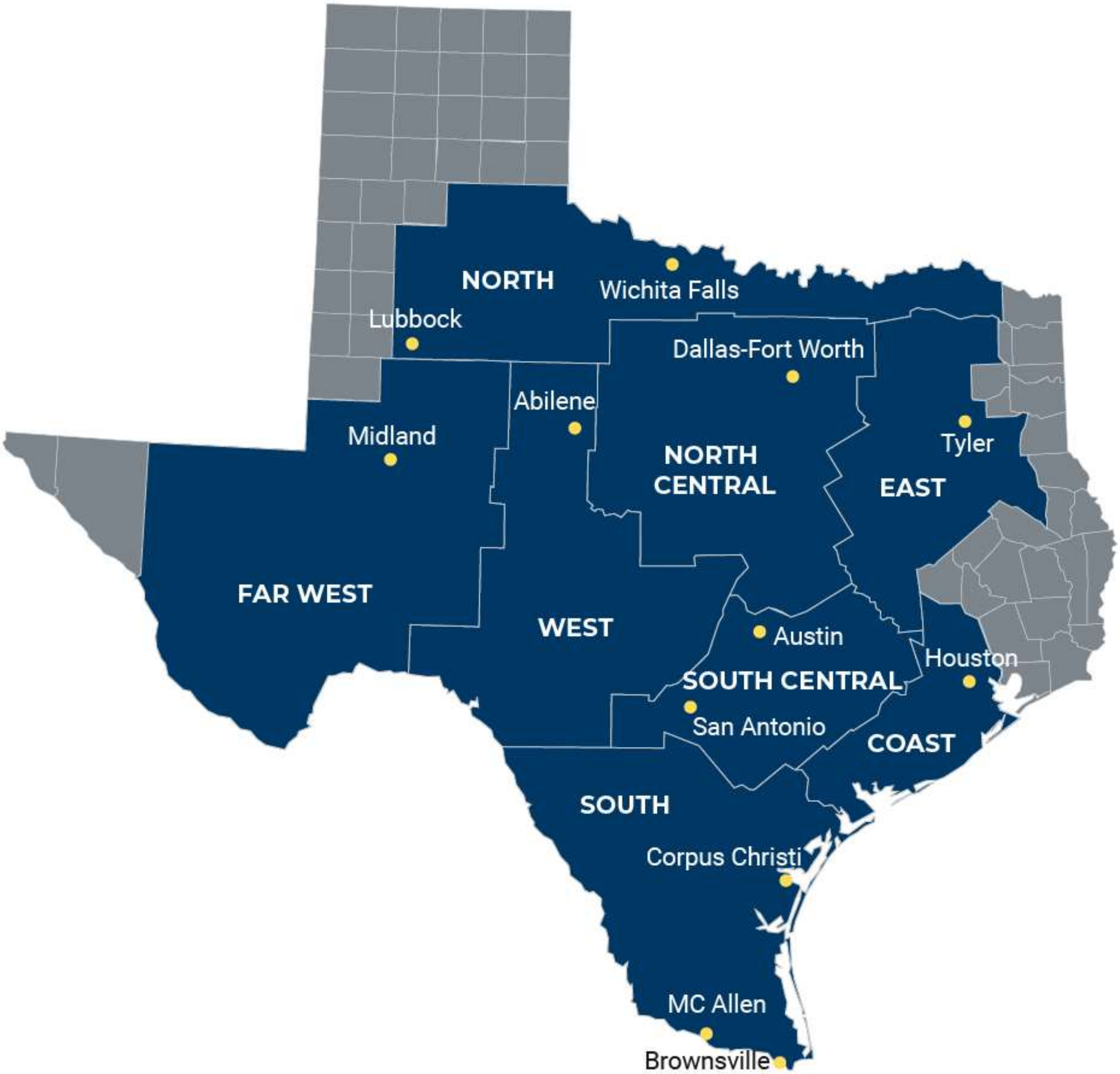
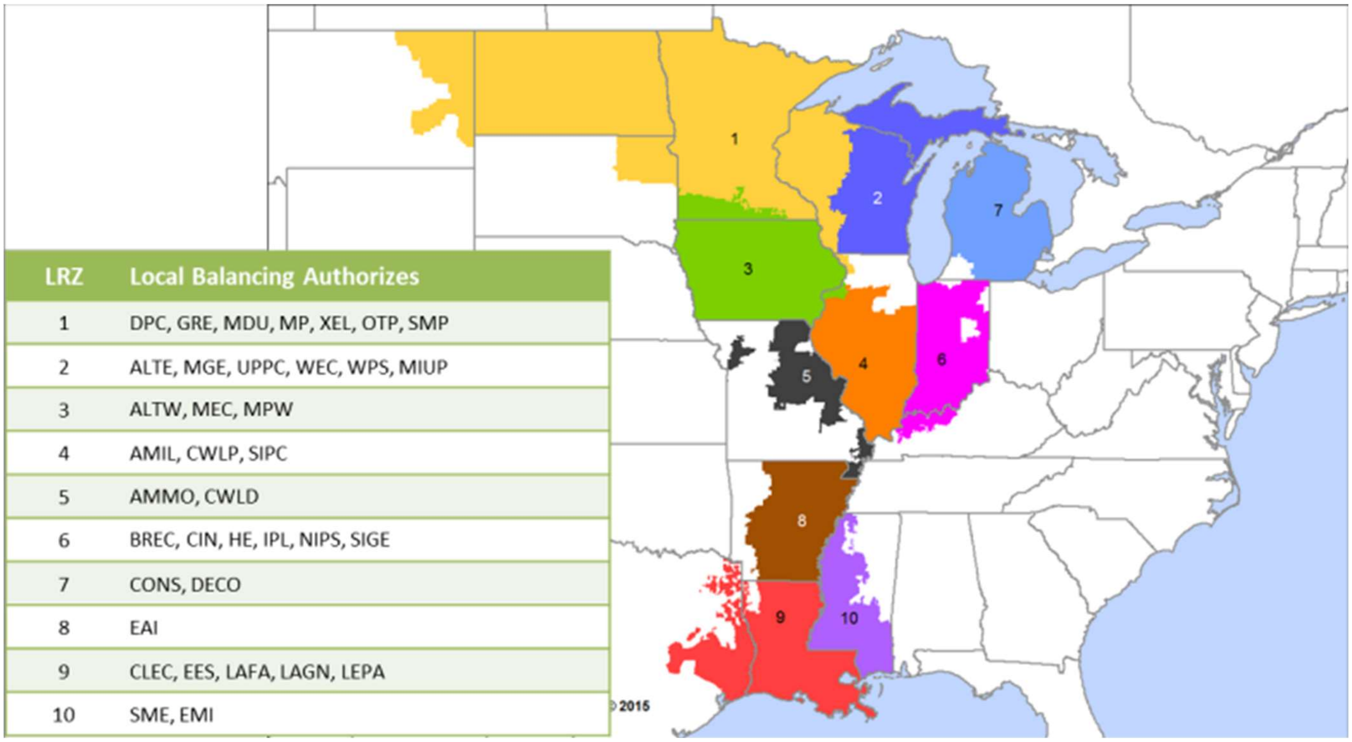


Figure 4: Map of ERCOT, showing weather zones[5]

[5] "ERCOT Weather Zone Map."



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

Figure 5: Map of MISO, showing Local Resource Zones (LRZs) and the Local Balancing Authorities (LBAs) within each LRZ[6]

[6] "MTEP18 Book 2 Resource Adequacy."

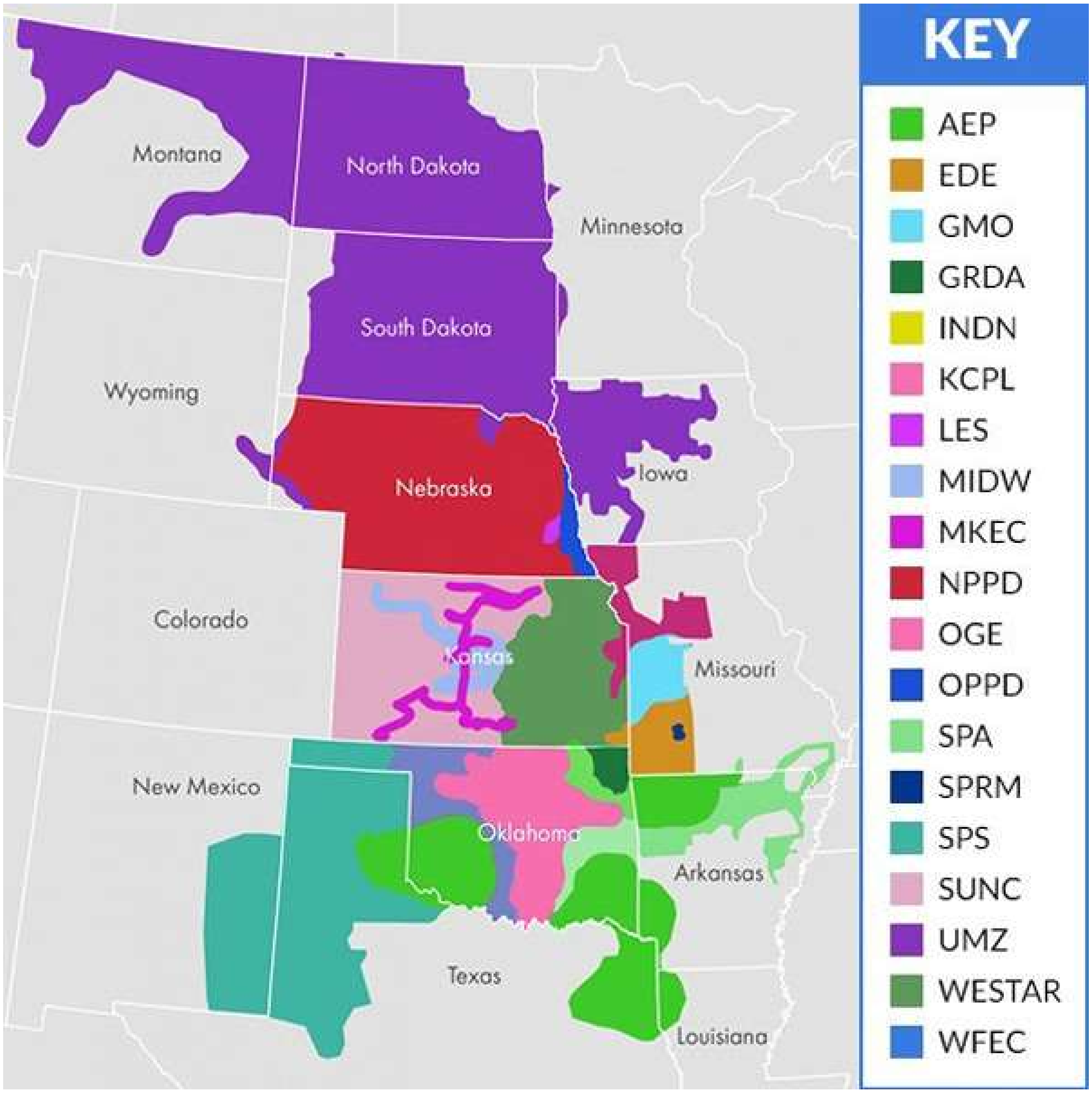


Figure 6: Map of SPP, showing Local Resource Zones (LRZs)[7]

[7] "FERC Accepts SPP's 2nd Try at Zonal Planning Criteria | RTO Insider."

A.2: Summary of Model Input Data and Strategy Implementation

A.2.1: Input Data

Input	Reference Section
2025 hourly generation profile for each generator type in each zone	A.4: Clean Energy Generation Profiles and Availability
2025 hourly load profile (varies by customer type and location)	A.3: Load Profiles
2025 forecasted zonal location marginal emission rates (LMERs) for each zone where customer load or procurable energy was located	A.5: Long-Term Market Forecast
2025 forecasted zonal locational marginal prices (LMPs) for each zone where procurable battery storage was located	A.5: Long-Term Market Forecast
2025 annualized procurement cost for each generator type in each zone ($/MW).	A.6: Clean Energy Procurement Cost
Battery storage capacity procurement cost (or tolling charge) for each zone ($/MW)	A.6.5: Battery Storage Cost Calculation

Each strategy was evaluated for 10 different customers – a customer with a flat load profile and a customer with a commercial retail load profile, in each of the 5 balancing authorities. The customers optimized for achieving their goal at lowest cost. For the annual energy matching and carbon matching strategies this was trivial, while for the hourly energy matching strategy a linear optimization model was formulated to solve for the least-cost solution for each customer.

A.2.2: Annual Energy Matching

Two annual energy matching strategies were evaluated: "annual energy matching", and "local annual energy matching."

In the annual energy matching strategy, the customer procures energy from the generator with the lowest annualized procurement cost such that the total annual generation from that generator equals their total annual load. The local annual energy matching strategy is the same except that the customer must procure energy within the same balancing authority as their load, while in annual energy matching energy procurement is not constrained.

Total cost is calculated using the annualized procurement cost for the procured energy, with the generator capacity scaled such that the generator produces enough energy to match the customer load on an annual basis. LMERs at the customer load location and the procured energy location are used to calculate the customer's net carbon footprint.

A.2.3: Carbon Matching

In the carbon matching strategy, the customer procures energy from the generator with the lowest annualized carbon displacement cost such that the total carbon displacement from that generator equals the carbon emissions attributable to the customer's load ("load emissions"). This strategy is analogous to the annual energy matching strategy, except that it translates load and procured energy into carbon emissions and displacement values using hourly, zonal LMERs.

Total cost is calculated using the annualized procurement cost for the procured energy, with the generator capacity scaled such that the generator displaces enough carbon to match the customer load emissions on an annual basis. The customer's net carbon footprint with this strategy is always zero.

A.2.4: Hourly Energy Matching

The hourly energy matching strategy is a more granular version of the local annual energy matching strategy. To achieve hourly energy matching, the customer must match their energy consumption with procured clean energy on an hourly basis in the same balancing authority.

For the hourly energy matching strategy, we allowed customers to procure battery storage capacity in addition to clean energy from a portfolio of wind, solar, and geothermal resources, and operate that battery in order to shift clean energy from hours of excess to hours of need. Battery storage could be procured in any zone in the same balancing authority as the customer's load, which allowed for further location optimization because LMPs varied by zone.

Model Formulation

In contrast with the other strategies, where least-cost optimization is trivial, the granularity of hourly matching and the addition of battery storage operation optimization required more detailed problem formulation and the use of a commercial solver (Gurobi).

The decision variables were the procured capacity of clean energy in each zone and for each generator type, the charge, discharge, and state of charge of the battery in each hour, the excess generation (positive difference between generation and load) in each hour, and the grid supply (negative difference between generation and load) in each hour:

Decision Variable	Explanation
$\boldsymbol{ProcuredEnergy_t}$	Total generation from procured clean energy resources
$\boldsymbol{Ch^{es}_{t,area}}$	Battery charge MW in hour t
$\boldsymbol{DC^{es}_{t,area}}$	Battery discharge MW in hour t
$\boldsymbol{SOC^{es}_{t,area}}$	Battery state-of-charge in hour t
$\boldsymbol{Excess_t}$	Excess generation above load in hour t
$\boldsymbol{GridSupply_t}$	Shortage of generation to match load in hour t

The key constraints in the model formulation were the energy balance, the carbon-free energy (CFE) target, and the excess energy limit:

Energy Balance: This constraint ensures that customer load in each hour is met by some combination of procured renewable energy, battery operation, and supply from the grid.

$$\boldsymbol{ProcuredEnergy}_t + \sum_{\boldsymbol{area}} (\boldsymbol{DC^{es}_{t,area}} - \boldsymbol{Ch^{es}_{t,area}}) - \boldsymbol{Excess_t} + \boldsymbol{GridSupply_t} - Load_t = 0 \quad \forall\, t$$

CFE Target: This constraint ensures that the input CFE target is met. The annual CFE score is calculated as the percentage of total hourly load that is matched by clean energy (including procured energy, energy shifted using battery storage, and clean energy from the grid). If the CFE target is 100%, then grid supply can only be used when the grid is supplying 100% clean energy.

$$\frac{\sum_t \boldsymbol{ProcuredEnergy}_t + \sum_{area} (\boldsymbol{DC^{es}_{t,area}} - \boldsymbol{Ch^{es}_{t,area}}) - \boldsymbol{Excess_t} + (\boldsymbol{GridSupply_t} * CFE)}{\sum_t (Load_t)} \geq TargetCFE$$

Excess Energy Limit: This constraint limits the total amount of procured renewable energy relative to the total customer load. A low excess energy limit means that the customer remains well-hedged in the energy market but must procure more battery storage to shift clean energy between hours.

$$\frac{\sum_t \boldsymbol{ProcuredEnergy}_t}{\sum_t Load_t} \leq ExcessEnergyLimit$$

Battery storage was subject to typical operating constraints, including limits on hourly charging and discharging based on capacity, and a limit on total state-of-charge based on total storage. State-of-charge was tracked hour by hour individually for each battery procured. In addition, in each hour all batteries combined could only charge up to the amount of procured renewable generation, though the battery storage and renewable generation are not assumed to be co-located.

The objective function was to minimize cost:

$$\sum_{unit,area} \boldsymbol{Cap_{unit,area}} Cost_{unit,area} + \sum_{t,area} (\boldsymbol{Ch^{es}_{t,area}} - \boldsymbol{DC^{es}_{t,area}}) * LMP^{es}_{t,area}$$

For the full formulation, please see APPENDIX B:

A.3: Load Profiles

Each procurement target was evaluated for two different load profiles, flat and retail. The flat load profile is meant to represent a data center, industrial, or other relatively stable load, while the retail load profile is meant to represent the electric usage of a large commercial retail building.

For the flat load, the electric demand is the same in every hour. The retail load shape source and selection are detailed below.

A.3.1: Retail Load Profile Source

The load profiles were created using data from NREL's End-Use Load Profiles for the U.S. Building Stock database, which contains energy-use load profiles for the 16 types of commercial buildings included in NREL's ComStock model.[8] The energy-use load profiles were produced by simulating commercial buildings across the U.S using ComStock. The load was estimated using the weather records for calendar year 2018 and has a 15-minute temporal resolution. Data are available for each simulated building as well as aggregated over larger regions by type and location.

8 "End-Use Load Profiles for the U.S. Building Stock."

A.3.2: Load Shape Selection

TCR used only data from the "Stand-alone Retail" building class across all available counties. Examining the various load profiles of those counties then revealed that the largest differences arose from the predominant heating method, either electric or fuel based. Each county was classified as having predominately 'mixed', 'electric', or 'fuel'-based heating based on the ratio of electric to fossil fuel heating. One representative county with the 'mixed' heating type was selected for each balancing authority.

In Figure 7, the values shown represent the average hourly load for 'Stand-alone Retail' buildings in each county over each month, divided by the total floor area of all commercial buildings simulated in each county (in units of kWh/100,000 ft^2). This method normalized the number and square footage of commercial buildings within each county.

Commercial retail load profiles were not normalized among customers, meaning that, for example, the commercial retail load customer in LADWP had higher total electric load than the customer in PJM.

For the flat load profile, the hourly load was assumed to be 1 MW for customers in all balancing authorities (not shown).

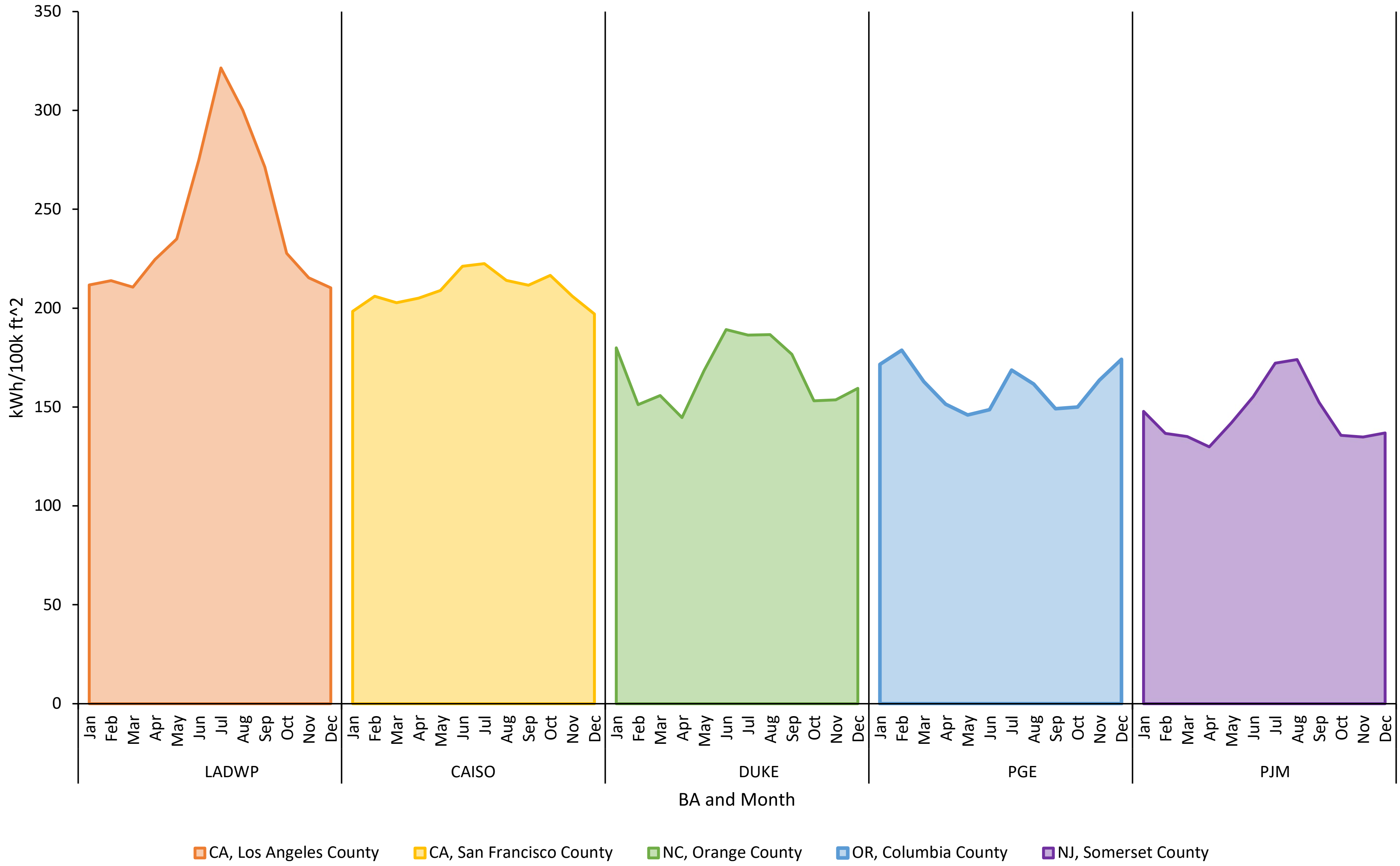


Figure 7: Total Monthly Electric Load Profiles for Stand-Alone Retail by Region

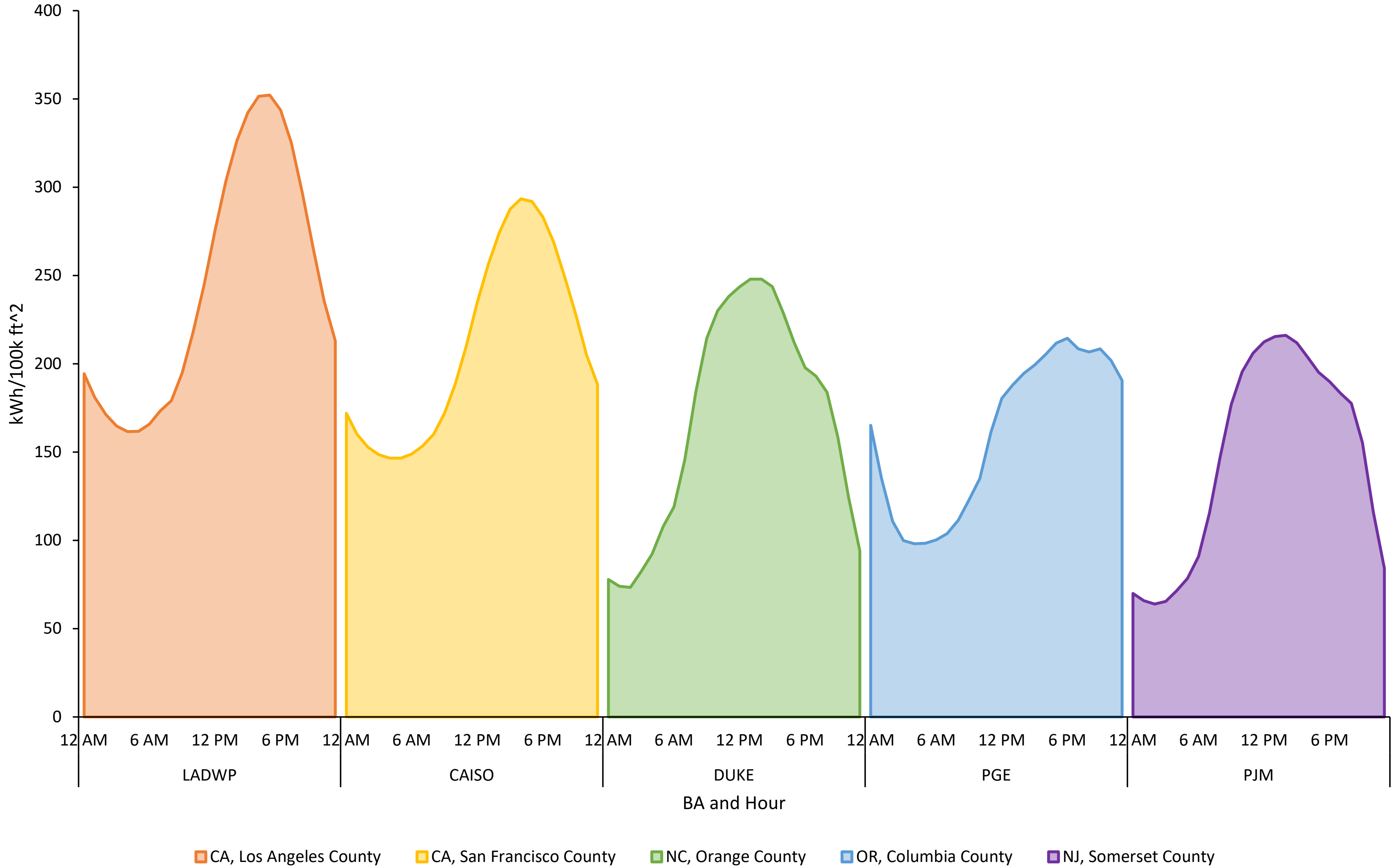


Figure 8: Total Hourly Electric Load Profiles for Stand-Alone Retail by Region

A.4: Clean Energy Generation Profiles and Availability

A.4.1: Clean Energy Generation Procurement Availability

Utility-scale solar and wind energy were available for procurement in each balancing authority except DUKE, where only solar was available. Due to geographic limitations, wind and solar procurement in LADWP and wind procurement in PGE were only available through wheeling from CAISO (for LADWP) and Bonneville Power Administration (for PGE). This was accompanied by a firm transmission contract, which raised procurement costs. In DUKE and LADWP, rooftop solar PV was also made available for procurement due to the existence of specific avoided cost rates or tariffs for rooftop solar. However, due to its higher cost, it was not selected for procurement by any customer.

In CAISO, hydrothermal geothermal capacity is also available for procurement. This decision was based on identified hydrothermal sites from the USGS Assessment of Moderate- and High-Temperature Geothermal Resources of the United States[9]. Enhanced Geothermal Systems were not considered for this analysis.

Each energy area within a balancing authority has a unique hourly generation profile available for procurement for each generator type. The PGE, LADWP, and DUKE balancing authorities each have just a single energy area, while the ISO/RTO regions each have several energy areas.

A.4.2: Clean Energy Generation Profiles

TCR assembles wind generation profiles from the National Renewable Energy Laboratory (NREL)'s Wind Integration National Dataset (WIND) Toolkit dataset, which is based on 2012 weather data.[10] For solar PV generation profiles, we obtained 2012 solar irradiation data from a representative weather station within each energy area using NREL's National Solar Radiation Database.[11] Then, solar irradiation was converted to generation using the NREL System Advisory Model. Table 2 summarizes the parameter assumptions used to calculate solar PV energy production.

Although 2012 weather data was used, all solar and wind shapes were calendar-shifted to 2025 for consistency with forecasted LMP and LMER values.

Table 2: Photovoltaic Parameter Assumptions

PV Parameters	Utility/Community	Rooftop
Module Type	Premium	Standard
Array Type	Single-axis tracking	Fixed Array – Roof Mount
Array Tilt (deg)	20	20
Array Azimuth (deg)	180	180
System Losses (%)	14	14
Invert Efficiency (%)	96	96

Table 3 summarizes the utility-scale solar and wind capacity factors for the five ISO/RTO balancing authorities included in the model. Each ISO/RTO had several zones in which customers could procure energy, and Table 3 shows the range of capacity factors across these zones. Customers were not

9 "Geothermal Resources of the United States."

10 "Wind Integration National Dataset Toolkit."

11 "NSRDB: National Solar Radiation Database."

located in ERCOT, MISO, and SPP in this analysis; however, utility-scale solar PV and wind were available for procurement in these balancing authorities for all customers pursuing the annual energy matching and carbon matching strategies. Table 4 summarizes the capacity factors in the VIEU balancing authorities for utility-scale and rooftop solar PV, as well as utility-scale wind. Procurement in these three balancing authorities was only allowed when the matched load was located within the same balancing authority.

Table 3: Summary of Solar and Wind Capacity Factors by ISO/RTO Balancing Authority

Balancing Authority	Utility-scale Solar			Utility-scale Wind		
	Min	Mean	Max	Min	Mean	Max
CAISO	18.9%	21.5%	24.2%	12.7%	20.2%	25.2%
ERCOT	20.7%	22.1%	24.5%	26.6%	32.1%	37.4%
MISO	16.4%	18.8%	20.8%	23.9%	32.0%	39.1%
PJM	16.8%	18.0%	19.0%	24.7%	28.4%	33.8%
SPP	19.4%	21.0%	24.7%	29.4%	37.0%	39.7%

Table 4: Summary of Solar and Wind Capacity Factors by VIEU Balancing Authority

Balancing Authority	Utility-scale PV	Rooftop PV	Utility-scale Wind
DUKE	17.3%	14.8%	27.3%
LADWP	24.4%	**17.5%**	28.0%
PGE	14.2%	--	24.5%

The cost assumptions for geothermal include an 80% capacity factor. In this analysis, geothermal was modeled as a dispatchable resource that could dispatch up to 80% of its procured capacity, with no outages or downtime.

A.4.3: Battery Storage

For hourly energy matching, battery storage could be procured to help balance renewable generation with load. Customers could procure battery storage in any energy area in the same balancing authority as their load, but not in other balancing authorities. Battery operation was optimized to maximize revenue and/or carbon displacement, depending on the procurement strategy.

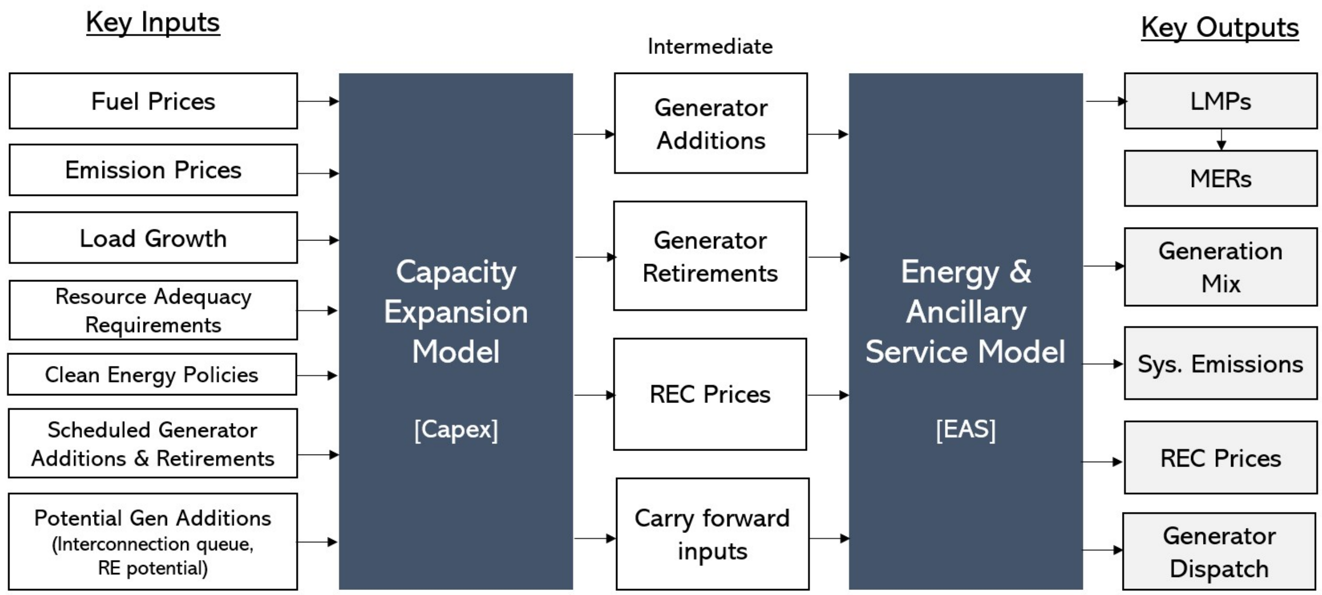
Battery storage was assumed to be utility-scale 4-hour lithium-ion battery storage participating in the wholesale energy market.

A.5: Long-Term Market Forecast

In this study, hourly locational marginal prices (LMPs) and location marginal emission rates (LMERs) from TCR's long-term market forecast were used. TCR's forecast uses a fundamentals-based capacity expansion and production cost model implemented in ENELYTIX, which is powered by the Power Systems Optimizer (PSO) market engine.

TCR uses ENELYTIX to develop internally consistent projections of generator additions and retirements as well as hourly marginal prices, marginal emission rates, and transmission congestion. TCR's long-term forecast involves two models: Capacity Expansion, to determine future generator additions and retirements in accordance with future cost assumptions, reliability requirements, and clean energy policies, and Energy & Ancillary Services, which is a production cost model that simulates hourly grid operation and produces nodal and zonal LMPs and LMERs. Results from the Capacity Expansion Model, which operates on a decades-long time horizon, are processed and used in the EAS model, which operates on a daily to weekly time horizon. Table 5 shows the interaction between these modules.

Table 5: Interaction of Capex and EAS model using ENELYTIX



The Capacity Expansion model determines system capacity mix change (generator addition and retirement), as well as the clearing price for capacity and renewable energy credit markets. The model includes relevant clean energy policy constraints in each region, such as RPS requirements and associated REC markets, mandated utility procurements, and emission pricing, including carbon pricing. It also includes system adequacy requirements relevant to each region, usually meaning the maintenance of a system-wide reserve margin as well as ensuring there is enough local capacity in specific import-constrained zones. Most importantly, it contains capital cost for new potential generating units, as well as O&M costs for new and existing units, and cost projections for fuels such as natural gas, coal, and fuel oil. The Capacity Expansion model also includes new generators that are in advanced development or under construction, and unit retirements scheduled by the owner or required by regulation. Transmission lines that are already approved or under construction are included, but the model does not solve for additional transmission expansion.

The Energy and Ancillary Services (EAS) model simulates Day-Ahead and Real-Time market operations using chronological simulations of the Security Constrained Unit Commitment (SCUC) and Economic Dispatch (SCED) processes, as well as procuring ancillary services in accordance with each region's requirements. The model is fully nodal, performs true MIP-based optimization, uses no heuristics, rigorously optimizes storage facilities, phase shifters, and HVDC operation, and properly accounts for marginal transmission losses. The result is nodal, hourly LMPs and LMERs that are also aggregated at the zonal and system level.

A.6: Clean Energy Procurement Cost

A.6.1: Procurement Cost Summary

For this analysis, we calculated procurement costs from the perspective of a corporate buyer looking to procure energy via a virtual power purchase agreement (PPA) or similarly structured contract.

Annualized procurement cost ($/MW) is calculated on a net basis, considering the contract price, or the cost to buy clean energy via a virtual power purchase agreement and the value of the procured clean energy to the local market or utility. The contract price was determined using PPA index values in ISO/RTO regions, and LCOE in VIEU regions. The value of the procured energy was determined using forecasted LMPs in ISO/RTO regions and avoided cost or feed-in tariff rates in the VIEU regions.

The annualized procurement cost does not consider capital expenditures, but only the hourly difference in the contract price and the value of energy. It is calculated for a single study year, 2025, with the understanding that in order to buy energy via a power purchase agreement, a multi-year contract would have to be entered into by the corporate customer.

In addition, annualized procurement cost was calculated on a per-MW basis without regard to the total amount of capacity procured. The value represents the cost to procure the energy generated by 1 MW of a utility-scale wind, solar PV, or geothermal generator in the year 2025. Customers in this analysis have average load around 1 MW, meaning that procured energy is often in the 1 MW range as well, despite being considered "utility-scale." This numerical range was chosen for simplicity, and all results can be linearly scaled up to any magnitude. In addition, results in terms of $/MWh or $/metric ton of CO_2 are independent of the magnitude of load or procured energy.

Battery storage capacity procurement cost was calculated based only on capital cost, not operating cost, because the battery operation is optimized by the customer for their specific hourly energy matching needs. This results in a $/MW capacity "tolling charge" to own or rent the battery capacity. This cost was annualized to 2025 only, with the understanding that the customer would need to enter into a multi-year contract or financing deal in order to procure the battery storage.

Table 6 below summarizes the sources used for both contract price and the value of energy for each balancing authority and generation type available.

Table 6: Summary of Procurement Cost Source by BA and Unit Type

	Balancing Authority	CAISO	PJM	PGE	LADWP	CAR
	BA Type	ISO/RTO	ISO/RTO	VIEU	VIEU	VIEU
Utility-Scale PV	*Contract Price*	2022Q3 LevelTen PPA price index	2022Q3 LevelTen PPA price index	Lazard Utility-scale PV LCOE v15.0, 'High'**Error! Bookmark not defined.**	--	Lazard Utility-scale PV LCOE v15.0, 'High'
	Value of Energy	Forecasted 2025 Zonal LMP	Forecasted 2025 Zonal LMP	PGE Avoided Cost Rate	--	DEC Avoided Cost Rate
Wind	*Contract Price*	2022Q3 LevelTen PPA price index	2022Q3 LevelTen PPA price index	Lazard Utility-scale Wind LCOE v15.0, 'High'+ firm transmission contract	CAISO price + firm transmission contract	Lazard Utility-scale Wind LCOE v15.0, 'High'
	Value of Energy	Forecasted 2025 Zonal LMP	Forecasted 2025 Zonal LMP	Forecasted 2025 Zonal LMP	Forecasted 2025 Zonal LMP	DEC Avoided Cost Rate
Geothermal	*Contract Price*	Lazard LCOE v15.0, "High"	--	--	--	--
	Value of Energy	Forecasted 2025 Zonal LMP	--	--	--	--

For battery storage, we used capital cost as the procurement cost rather than energy cost, because battery operation was optimized as part of the model formulation – see Section A.6.5: below.

Table 16 shows the annualized procurement cost by energy area for all 3 generator types and battery storage (which is available for the 24x7 hourly energy matching strategy). For geothermal, solar PV, and wind, these procurement costs are calculated using the difference between contract price (PPA or LCOE) and energy value (hourly LMP or utility avoided cost rate).

For battery storage, procurement cost in this table is only annualized capital cost, or 'tolling charge'. Battery storage also may generate revenue or incur extra cost through charging and discharging at wholesale prices.

A.6.2: ISO/RTO Wind and Solar Annualized Procurement Cost Calculation

For ISO/RTO regions, the contract price was based on P25 PPA index prices from the 2022Q3 LevelTen Energy PPA Price Index[12]. LevelTen PPA prices are available at the pricing hub level, and these pricing hubs were mapped to energy areas – see Appendix C, Table 16.

Where there wasn't data for Q3 of 2022, the most recent LevelTen 2022 PPA index price for that pricing hub was used; where no data for any quarter of 2022 existed, no PPA price was used, and the energy areas mapped to that pricing hub were considered ineligible for that form of renewable generation.

The hourly wholesale value of energy was set using 2025 Locational Marginal Prices (LMPs) from TCR's proprietary long-term forecast of U.S. nodal power prices and marginal emission rates (MERs). See section A.5: for details.

An annualized procurement cost per MW capacity was calculated for each generator in each energy area using the following formula:

$$Cost\left(\frac{\$}{MW - year}\right) = \sum_{t=1}^{8760}(PPA\ - LMP_t) * generation_t$$

where…

- PPA is the index PPA price for the hub that corresponds to the energy area of the unit.
- LMP is the hourly zonal Locational Marginal Price in the same energy area as the generation unit.
- Generation is the hourly output of that unit, normalized to a 1 MW capacity.

The resulting cost was the total cost to procure 1 MW of capacity from this generator for 1 year.

A.6.3: VIEU Wind and Solar Annualized Procurement Cost Calculation

The three VIEU balancing authorities in this analysis do not have open wholesale markets for energy. This means that, unlike in the ISO/RTO regions, procured energy cannot be sold at market price. Instead, the developer and/or corporate purchaser must enter into a contract to sell the energy to the utility.

In VIEU regions, the contract price was based on the "high" estimate from the Lazard Levelized Cost of Energy (LCOE) Analysis v15.0[13], adjusted using EIA EMM regional multipliers[14]. Because the Lazard LCOE v15.0 analysis was released in October 2021, LCOEs were also adjusted based on the average percentage change between the 2021Q4 and 2022Q3 LevelTen price index to bring them up to date with the state of the market as of 2022Q3.

In VIEU regions, utility avoided cost or feed-in tariff rates were used for the value of energy. Under PURPA, qualifying electric generating facilities have the right to sell power to a utility under certain

12 "Q4 2021 PPA Price Index."

13 "Lazard's Levelized Cost of Energy Analysis — Version 15.0."

14 "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022."

circumstances[15]. This is generally done using a utility's avoided cost rate, which is a standard rate at which a utility will purchase energy. For Portland General Electric and Duke Energy Carolinas, avoided cost rates were used.

PGE's avoided cost rates are available for qualifying facilities up to 10 MW in capacity for wind, and up to 3 MW for solar. There is a lower "standard" rate or a higher "renewable" rate, which required the resources to cede all clean energy attributes such as RECs.[16] TCR used the "standard" prices, assuming that the corporate purchaser would want to claim and retire any RECs. The PGE avoided cost rate is summarized in Table 7.

Table 7: Summary of PGE Avoided Costs

Resource		Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PV	On-peak	6am - 10pm	$31.77	$31.07	$29.31	$27.07	$27.01	$27.46	$27.92	$28.10	$28.02	$28.47	$29.83	$31.85
PV	Off-peak	10pm - 6am	$26.07	$25.37	$23.61	$21.37	$21.30	$21.76	$22.21	$22.40	$22.32	$22.76	$24.13	$26.14
Wind	On-peak	6am - 10pm	$42.68	$41.98	$40.22	$37.98	$37.92	$38.37	$38.82	$39.01	$38.93	$39.38	$40.74	$42.75
Wind	Off-peak	10pm - 6am	$27.21	$26.51	$24.75	$22.51	$22.44	$22.90	$23.35	$23.54	$23.46	$23.90	$25.27	$27.28

Duke Energy Carolinas has several different avoided cost rate structures. There are variable and fixed rates, rates for transmission interconnection vs distribution-level interconnection, and separate rates for PV and wind[17]. For this analysis, the 2025 fixed transmission rate for wind and solar qualifying facilities was used. The DUKE avoided cost rates are summarized in Table 8.

Table 8: Summary of DUKE Avoided Costs

DUKE Avoided costs		Weekdays						Weekends & Holidays	
Season	Months	On-peak ($/MWh)		Off-peak ($/MWh)		Premium Peak ($/MWh)		Off-peak ($/MWh)	
Winter	Dec-Feb	4am - 6am	$44.00	11am-6pm	$39.40	6am-9am	$58.30	-	$39.40
		9am - 11am	$44.00	10pm - 4am	$39.40	-	-	-	$39.40
		6pm - 10pm	$48.30	-	-	-	-	-	-
Shoulder	Mar-May	5am - 10am	$36.90	10am-5pm	$28.50	-	-	-	$28.50
	Oct-Nov	5pm - 11pm	$36.90	11pm-5am	$28.50	-	-	-	$28.50
Summer	Jun-Sep	1pm - 4pm	$35.60	9pm - 1pm	$33.00	4pm-8pm	$38.80	-	$33.00
		8pm - 9pm	$35.60	-	-	-	-	-	-

For LADWP, the LADWP Feed-in Tariff (FiT) program was used rather than an avoided cost rate (see Table 9).[18] The feed-in tariffs are significantly higher than the avoided cost rates in PGE and DUKE, but they can only be earned by a limited set of resources (180 MW total) selected through an application process. For this analysis, TCR used the in-basin medium-scale FiT of $140; the in-basin indicates that the solar installation is in the Los Angeles valley.

15 "PURPA Qualifying Facilities | Federal Energy Regulatory Commission."

16 "UM 1728 Compliance Filing to Update Schedule 201 Qualifying Facility Information."

17 "PURCHASED POWER SCHEDULE PP-9."

18 "Feed-in Tariff (FiT) Program."

Table 9: Summary of Feed-in Tariff Prices for LADWP

Project Capacity	In-Basin Projects		Owens Valley Projects
	Solar PV	Non-PV	Solar PV
30 kW - 500 kW	$145 per MWh	$115 per MWh	$115 per MWh
> 500 kW - 3 MW	$140 per MWh	$110 per MWh	Not Available
> 3 MW	$135 per MWh	$105 per MWh	Not Available

For VIEU regions, no PPA price index was available, as many fewer power purchase agreements are executed in these regions. Instead of a PPA price, Levelized Cost of Energy (LCOE) was used as the procurement cost (see Table 10). TCR used Lazard's Levelized Cost of Energy (LCOE) Analysis, version 15.[19] For all technologies, the 'high' scenario from the Lazard study was used as the base LCOE. For each energy area, the LCOE was modified using regional cost modifiers computed from the EIA's Cost and Performance Characteristics of New Generating Technologies report from the 2022 Annual Energy Outlook.[20]

Table 10: Regional LCOE Values ($/MWh) for Solar and Wind for VIEU Balancing Authorities

Balancing Authority	Utility-scale Solar	Utility-scale Wind
Lazard High	*$41.00*	*$50.00*
DUKE	$41.49	$48.98
LADWP	$44.49	-
PGE	$41.15	$59.87

An annualized procurement cost per MW capacity was calculated for each generator in VIEU region using the following formula:

$$Cost\left(\frac{\$}{MW - year}\right) = \sum_{t=1}^{8760} (LCOE \ - AC/FiT_t) * generation_t$$

Where…

- LCOE is the 'high' scenario from the Lazard v15.0 LCOE Analysis, adjusted using EIA regional multipliers.
- AC/FiT is the hourly avoided cost or feed-in tariff rate in the same energy area as the generation unit.
- Generation is the hourly output of that unit, normalized to a 1 MW capacity.

The resulting annualized procurement cost is the total cost to procure 1 MW of capacity from this generator for 1 year.

19 "Lazard's Levelized Cost of Energy Analysis — Version 15.0."

20 "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022."

A.6.4: Geothermal Cost Calculation

Since there are no PPA index prices for geothermal, TCR used the 'high' Lazard LCOE as the contract price, like for solar and wind in the VIEU regions. This LCOE, combined with the EIA regional price multipliers, resulted in a contract price of $94/MWh for CIPB and CIPV energy areas (northern California), and $76.10/MWh for the CISC and CISD energy areas (southern California). The Lazard 'high' geothermal LCOE assumed an 80% capacity factor, which was used as a dispatch limit for procured geothermal capacity.

The geothermal cost formula was analogous to the formula for wind and solar:

$$Cost\left(\frac{\$}{MW - year}\right) = \sum_{t=1}^{8760}(LCOE\ - LMP_t) * generation_t$$

where…

- LCOE is the 'high' scenario from the Lazard v15.0 LCOE Analysis, adjusted using EIA regional multipliers.
- LMP is the zonal Locational Marginal Price in the same energy area as the generation unit.
- Generation is the hourly output, which for geothermal is 80% of procured capacity in every hour.

The resulting annualized procurement cost is the total cost to procure 1 MW of capacity from this generator for 1 year.

A.6.5: Battery Storage Cost Calculation

In this analysis, battery storage costs were a combination of two costs: equivalent annual capital cost (EAC) and market revenue from wholesale operation. The EAC estimate was based on assumptions from Lazard's Levelized Cost of Storage (LCOS) Analysis version 7.0[21]. The 'high' estimates for both capital cost of capacity and capital cost of storage were used to calculate the initial installed cost (IIC). Engineering and Procurement Costs (EPC) from Lazard were also included.

$$IIC = \ Capital\ cost\ of\ capacity\ \left[\frac{\$}{kW}\right] * Capacity\ [kW] + Capital\ cost\ of\ storage\left[\frac{\$}{kWh}\right] * Storage\ [kWh] + EPC\ costs\ [million\ \$]$$

For all Capex estimates, these IIC estimates were annualized into EAC using Lazard's cost of equity and cost of debt assumptions. Finally, EAC values for battery storage were modified for each energy area using the EIA regional multipliers.

In addition to capital cost, battery cost included market revenue from charging and discharging. Batteries incurred costs when charging from the grid equal to the zonal LMP multiplied by total energy for charging, and they generated revenue when discharging equal to the zonal LMP multiplied by total discharge. Battery round-trip efficiency (85% for this analysis) was modeled to be on the charging side only, such that for every 1 MWh drawn from the grid, 0.85 MWh could be stored and dispatched. Each battery unit began and ended the study period with a state of charge of 50%. Table 11 shows the key battery storage operational assumptions.

21 "Lazard's Levelized Cost of Storage Analysis — Version 7.0."

Table 11: Battery Storage Operational Assumptions

Parameter	Value
Round-trip Efficiency	85% (modeled on charging side only)
Total Storage	4 hours
Initial Storage	50% of total storage

Although DUKE, LADWP, and PGE do not have wholesale markets for energy, battery charging and discharging costs were still calculated using TCR's hourly zonal LMP forecasts for those regions.

In total, the cost of battery storage was the sum of the capital cost and operational cost:

$$EAC * EIA\ Regional\ Multiplier + \sum_{t=1}^{8760} (Charging_t * Efficiency - Discharging_t) * LMP_t$$

GLOSSARY

Term	Definition
AEO	EIA Annual Energy Outlook
ATB	NREL Annual Technology Baseline
CAISO	California Independent System Operator
DUKE	Duke Energy Carolinas
EAC	Equivalent Annual Cost
EIA	US Energy Information Administration
EPC	Engineering Procurement and Construction
ERCOT	Electric Reliability Council of Texas
ES	Energy Storage
FiT	Feed-in Tariff
IIC	Initial Installed Cost
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LCOE	Levelized Cost of Electricity
LCOS	Levelized Cost of Storage
LMP	Locational Marginal Price
MER	Marginal Emission Rate
MISO	Midcontinent System Operator
MW	Megawatt
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory
PGE	Portland General Electric
PJM	PJM Interconnection
PPA	Power purchase agreement
PV	Photovoltaic
REC	Renewable Energy Certificate/Credit
SPP	Southwest Power Pool
VIEU	Vertically Integrated Electric Utility
WIND	NREL Wind Integration National Dataset

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LIST OF FIGURES

LIST OF TABLES

APPENDIX B: Hourly Energy Matching Model Formulation

B.1: Decision Variables (boldface):

Table 12: Decision Variables

Decision Variable	Explanation	Indices
$\boldsymbol{Cap_{unit,area}}$	Procured capacity from clean energy resources	Unit type, zone
$\boldsymbol{Ch^{es}_{t,area}}$	Battery charge MW in hour t	Hour, zone
$\boldsymbol{DC^{es}_{t,area}}$	Battery discharge MW in hour t	Hour, zone
$\boldsymbol{SOC^{es}_{t,area}}$	Battery state-of-charge in hour t	Hour, zone
$\boldsymbol{Excess_t}$	Excess generation above load in hour t	Hour
$\boldsymbol{GridSupply_t}$	Shortage of generation to match load in hour t	Hour

B.2: Vector Inputs:

Table 13: Vector Inputs

Vector Inputs	Explanation	Indices
$Load_t$	Customer load in hour t	Hour
$Disp_{t,gen,zone}$	Normalized generation in hour t	Hour, unit type, zone
$Cost_{unit,zone}$	Annualized procurement cost ($/MW-year)	Unit type, zone
$LMP_{t,zone}$	Forecasted zonal LMP in hour t	Hour, zone
$LMER_{t,zone}$	Forecasted zonal LMER in hour t	Hour, zone
CFE_t	Grid carbon-free generation percentage in hour t	Hour

B.3: Scalar Inputs

Table 14: Scalar Inputs

Vector Inputs	Explanation
V	Battery storage duration
ε	Battery storage round-trip efficiency
δ	Battery initial and final storage target
$TargetCFE$	Target carbon-free energy % for customer

$ExcessLimit$	Limit on total energy procurement relative to load ('energy/load ratio')
T	Total number of hours (8760 for this annual model)

B.4: Indices

Table 15: Indices for vector variables and inputs

Indices	Explanation
t	Hours, from 1 to T (8760)
$unit$	Utility-scale PV, wind, geothermal, and battery storage
gen	Units that generate energy (PV, wind, geothermal) – subset of $unit$
$zone$	Zones within the target balancing authority

B.5: Objective Function:

$$\text{minimize } \sum_{unit,zone} \boldsymbol{Cap}_{\boldsymbol{unit},zone} Cost_{unit,zone} + \sum_{t,zone} (\boldsymbol{Ch}^{\boldsymbol{es}}_{\boldsymbol{t},zone} - \boldsymbol{DC}^{\boldsymbol{es}}_{\boldsymbol{t},zone}) * LMP^{es}_{t,zone}$$

B.6: Constraints:

Helper Equation

$$\boldsymbol{ProcuredEnergy_t} = \sum_{zone} (\sum_{gen} (Disp_{t,gen,zone} \boldsymbol{Cap}_{\boldsymbol{gen},zone})$$

Energy Balance

$$\boldsymbol{ProcuredEnergy_t} + \sum_{zone} (\boldsymbol{DC}^{\boldsymbol{es}}_{\boldsymbol{t},zone} - \boldsymbol{Ch}^{\boldsymbol{es}}_{\boldsymbol{t},\boldsymbol{area},zone}) - \boldsymbol{Excess_t} + \boldsymbol{GridSupply_t} - Load_t = 0 \quad \forall\, t = 1, \dots, T$$

$$\frac{\sum_t \boldsymbol{ProcuredEnergy_t} + \sum_{area} (\boldsymbol{DC}^{\boldsymbol{es}}_{\boldsymbol{t},zone} - \boldsymbol{Ch}^{\boldsymbol{es}}_{\boldsymbol{t},zone}) - \boldsymbol{Excess_t} + (\boldsymbol{GridSupply_t} * CFE)}{\sum_t (Load_t)} \geq TargetCFE$$

$$\frac{\sum_t \boldsymbol{ProcuredEnergy_t}}{\sum_t Load_t} \leq ExcessLimit$$

Battery storage state of charge balance

$$0 = \boldsymbol{Cap_{es}} V\delta - \sum_{zone} \boldsymbol{SOC}^{\boldsymbol{es}}_{\boldsymbol{t},zone} + (\varepsilon \boldsymbol{Ch}^{\boldsymbol{es}}_{\boldsymbol{t},zone}) - \boldsymbol{DC}^{\boldsymbol{es}}_{\boldsymbol{t},zone} \qquad t = 1$$

$$0 = \sum_{area} \boldsymbol{SOC}^{\boldsymbol{es}}_{\boldsymbol{t-1},zon} - \boldsymbol{SOC}^{\boldsymbol{es}}_{\boldsymbol{t},zone} + \varepsilon \boldsymbol{Ch}^{\boldsymbol{es}}_{\boldsymbol{t},zone} - \boldsymbol{DC}^{\boldsymbol{es}}_{\boldsymbol{t},zone} \qquad \forall\, t = 2, \dots, T-1$$

$$0 = \sum_{area} \boldsymbol{Cap}_{\boldsymbol{es},zone} V\delta - \boldsymbol{SOC}^{\boldsymbol{es}}_{\boldsymbol{t},zone} \qquad t = T$$

Battery storage limitations

$$\sum_{\boldsymbol{t}} \boldsymbol{DC}^{\boldsymbol{es}}_{\boldsymbol{t},zone} - \boldsymbol{Cap}_{\boldsymbol{es},zone} \leq 0 \quad \forall\, t = 1, \dots, T$$

$$\sum_{t} \boldsymbol{Ch_{t,zone}^{es}} - \boldsymbol{Cap_{es,zone}} \leq 0 \quad \forall\, t = 1, \dots, T$$

$$\sum_{\boldsymbol{t}} \boldsymbol{SOC_{t,zone}^{es}} - V * \boldsymbol{Cap_{es,zone}} \leq 0 \quad \forall\, t = 1, \dots, T$$

$$\sum_{\boldsymbol{zone}} \boldsymbol{Ch_{t,zone}^{es}} - \boldsymbol{ProcuredEnergy_t} \leq 0 \quad \forall\, t = 1, \dots, T$$

APPENDIX C: Auxiliary Tables

Table 16: Annualized Procurement Cost ($/kW-year)

		Geothermal	Solar PV		4-Hour Battery Storage	Wind
Balancing Authority	Zone	Utility-scale	Rooftop	Utility-scale	Utility-scale	Utility-scale
CAISO	CIPB	588.8	-	-	87.9	80.2
CAISO	CIPV	616.0	-	-	87.9	71.8
CAISO	CISC	497.9	-	46.5	88.1	86.7
CAISO	CISD	477.5	-	42.5	88.1	48.5
DUKE	DUKE	-	174.4	27.7	87.2	-
ERCOT	WZ_COAST	-	-	28.8	84.4	39.2
ERCOT	WZ_EAST	-	-	20.3	84.4	-
ERCOT	WZ_FAR_WEST	-	-	32.1	84.4	46.1
ERCOT	WZ_NORTH	-	-	28.2	84.4	47.2
ERCOT	WZ_NORTH_CENTRAL	-	-	18.9	84.4	-
ERCOT	WZ_SOUTH_CENTRAL	-	-	-	84.4	-
ERCOT	WZ_SOUTHERN	-	-	21.0	84.4	41.6
ERCOT	WZ_WEST	-	-	32.8	84.4	61.9
LADWP	LDWP	-	514.0	-	88.1	-
LADWP	SCE	-	-	68.5	88.1	106.5
MISO	ALTE	-	-	42.5	83.5	-
MISO	ALTW	-	-	39.2	83.5	79.0
MISO	AMIL	-	-	39.7	87.5	60.4
MISO	AMMO	-	-	43.1	87.5	68.2
MISO	BREC	-	-	43.2	87.5	-
MISO	CLECO	-	-	29.0	86.4	-
MISO	CON	-	-	-	84.6	98.4
MISO	CWLD	-	-	43.0	87.5	66.5
MISO	CWLP	-	-	38.1	87.5	58.4
MISO	DECO	-	-	-	84.6	102.8
MISO	DEI	-	-	41.5	87.5	-
MISO	DPC	-	-	39.6	83.5	-
MISO	EAI	-	-	37.6	86.4	-
MISO	EES-LA-TX	-	-	29.7	86.4	-
MISO	EES-MS-AR	-	-	-	86.4	-
MISO	GRE	-	-	39.7	83.5	-
MISO	HE	-	-	41.4	87.5	-
MISO	IPL	-	-	41.1	87.5	-
MISO	LAFA	-	-	-	86.4	-
MISO	LAGN	-	-	28.8	86.4	-
MISO	LEPA	-	-	-	86.4	-
MISO	MDU	-	-	44.4	83.5	-
MISO	MEC	-	-	41.0	83.5	80.6

		Geothermal	Solar PV		4-Hour Battery Storage	Wind
Balancing Authority	**Zone**	**Utility-scale**	**Rooftop**	**Utility-scale**	**Utility-scale**	**Utility-scale**
MISO	MGE	-	-	40.5	83.5	-
MISO	MP	-	-	39.9	83.5	-
MISO	MPW	-	-	38.5	83.5	67.4
MISO	NIPS	-	-	41.3	87.5	-
MISO	NSP	-	-	41.5	83.5	-
MISO	OTP	-	-	40.2	83.5	-
MISO	SIGE	-	-	40.2	87.5	-
MISO	SIPC	-	-	41.0	83.5	51.1
MISO	SME	-	-	-	86.4	-
MISO	SMP	-	-	41.2	83.5	-
MISO	UPPC	-	-	35.5	83.5	-
MISO	WEC	-	-	40.6	83.5	-
MISO	WPS	-	-	40.8	83.5	-
PGE	BPAT	-	-	63.6	86.5	182.0
PGE	PGE	-	-	31.0	86.5	90.9
PJM	AE	-	-	-	85.0	-
PJM	AEP	-	-	42.6	84.2	36.0
PJM	APS	-	-	50.3	84.2	67.5
PJM	ATSI	-	-	41.7	84.2	44.0
PJM	BGE	-	-	-	85.0	-
PJM	COMED	-	-	41.8	85.3	-
PJM	DAY	-	-	42.4	84.2	46.2
PJM	DEOK	-	-	44.1	84.2	39.1
PJM	DOM	-	-	49.5	85.0	-
PJM	DPL	-	-	-	85.0	-
PJM	DQE	-	-	48.6	84.2	70.4
PJM	EKPC	-	-	45.0	84.2	35.5
PJM	JCPL	-	-	-	85.0	-
PJM	METED	-	-	-	85.0	-
PJM	PECO	-	-	-	85.0	-
PJM	PENLC	-	-	61.0	85.0	88.2
PJM	PEPCO	-	-	-	85.0	-
PJM	PPL	-	-	-	85.0	-
PJM	PSEG	-	-	-	85.0	-
PJM	RECO	-	-	-	85.0	-
SPP	AEPW	-	-	21.9	84.0	37.0
SPP	EDE	-	-	19.2	84.5	36.6
SPP	GMO	-	-	19.4	83.5	49.6
SPP	GRDA	-	-	22.2	84.0	58.2
SPP	INDN	-	-	20.1	84.5	58.1
SPP	KACY	-	-	19.1	84.5	-
SPP	KCPL	-	-	20.8	84.5	49.0

		Geothermal	Solar PV		4-Hour Battery Storage	Wind
Balancing Authority	**Zone**	**Utility-scale**	**Rooftop**	**Utility-scale**	**Utility-scale**	**Utility-scale**
SPP	LES	-	-	47.8	83.5	39.8
SPP	MIDW	-	-	26.5	84.5	61.2
SPP	NPPD	-	-	51.3	83.5	40.5
SPP	OKGE	-	-	23.3	84.0	61.2
SPP	OMPA	-	-	24.8	84.0	60.7
SPP	OPPD	-	-	46.6	83.5	38.9
SPP	SECI	-	-	29.0	84.5	69.4
SPP	SPRM	-	-	16.3	84.5	-
SPP	SPS	-	-	38.8	84.0	56.1
SPP	WAPA	-	-	49.1	83.5	34.1
SPP	WFEC	-	-	23.4	84.0	57.0
SPP	WR	-	-	22.7	84.5	63.3

Table 17: Average PV and Wind capacity factors by energy area

Balancing Authority	Energy Area	PV Average CF	Wind Average CF
CAISO	CIPB	18.9%	25.2%
CAISO	CIPV	20.6%	20.9%
CAISO	CISC	24.2%	22.0%
CAISO	CISD	22.5%	12.7%
DUKE	DUKE	18.0%	26.4%
ERCOT	WZ_COAST	20.9%	27.4%
ERCOT	WZ_EAST	20.7%	26.6%
ERCOT	WZ_FAR_WEST	24.5%	31.9%
ERCOT	WZ_NORTH	23.1%	37.4%
ERCOT	WZ_NORTH_CENTRAL	21.6%	33.2%
ERCOT	WZ_SOUTH_CENTRAL	21.2%	33.6%
ERCOT	WZ_SOUTHERN	22.0%	33.6%
ERCOT	WZ_WEST	22.6%	32.9%
LADWP	LDWP	25.4%	-
MISO	ALTE	18.3%	32.7%
MISO	ALTW	18.3%	39.1%
MISO	AMIL	19.0%	33.8%
MISO	AMMO	19.6%	34.0%
MISO	BREC	19.7%	28.0%
MISO	CLECO	20.6%	24.8%
MISO	CON	17.8%	33.4%
MISO	CWLD	19.4%	34.2%
MISO	CWLP	19.1%	34.3%
MISO	DECO	17.6%	34.5%
MISO	DEI	19.0%	34.0%
MISO	DPC	17.3%	-
MISO	EAI	20.8%	-

Balancing Authority	Energy Area	PV Average CF	Wind Average CF
MISO	EES-LA-TX	20.7%	25.4%
MISO	EES-MS-AR	20.4%	25.9%
MISO	GRE	17.3%	33.7%
MISO	HE	19.0%	27.1%
MISO	IPL	18.8%	31.8%
MISO	LAFA	-	25.4%
MISO	LAGN	20.5%	25.5%
MISO	LEPA	20.4%	32.6%
MISO	MDU	17.7%	-
MISO	MEC	18.9%	39.0%
MISO	MGE	18.3%	35.5%
MISO	MP	17.4%	33.4%
MISO	MPW	18.6%	34.9%
MISO	NIPS	18.4%	-
MISO	NSP	18.1%	32.3%
MISO	OTP	17.0%	38.5%
MISO	SIGE	19.3%	-
MISO	SIPC	19.5%	-
MISO	SME	20.3%	23.9%
MISO	SMP	17.8%	35.6%
MISO	UPPC	16.4%	34.0%
MISO	WEC	18.3%	-
MISO	WPS	18.0%	-
PGE	PGE	15.2%	23.7%
PJM	AE	18.1%	30.5%
PJM	AEP	17.6%	24.7%
PJM	APS	18.0%	25.9%
PJM	ATSI	17.0%	28.9%
PJM	BGE	18.4%	29.1%
PJM	COMED	18.7%	33.8%
PJM	DAY	18.1%	31.8%
PJM	DEOK	18.7%	27.1%
PJM	DOM	18.8%	-
PJM	DPL	19.0%	29.7%
PJM	DQE	17.2%	26.2%
PJM	EKPC	18.7%	24.8%
PJM	JCPL	17.5%	28.3%
PJM	METED	17.6%	26.5%
PJM	PECO	17.6%	-
PJM	PENLC	17.5%	27.8%
PJM	PEPCO	18.4%	27.9%
PJM	PPL	16.8%	-
PJM	PSEG	17.7%	-
PJM	RECO	-	31.7%
SPP	AEPW	20.5%	-

Balancing Authority	Energy Area	PV Average CF	Wind Average CF
SPP	EDE	20.5%	29.4%
SPP	GMO	19.4%	35.6%
SPP	GRDA	20.6%	38.4%
SPP	INDN	19.9%	37.1%
SPP	KACY	20.2%	-
SPP	KCPL	20.1%	35.2%
SPP	LES	20.5%	38.0%
SPP	MIDW	21.9%	38.0%
SPP	NPPD	20.8%	38.7%
SPP	OKGE	21.8%	39.7%
SPP	OMPA	22.7%	38.5%
SPP	OPPD	20.0%	-
SPP	SECI	22.4%	38.8%
SPP	SPRM	20.4%	-
SPP	SPS	24.7%	35.0%
SPP	WAPA	19.5%	36.1%
SPP	WFEC	21.8%	36.9%
SPP	WR	21.2%	39.4%
Average:		19.5%	31.4%
Maximum:		25.4%	39.7%
Minimum:		15.2%	12.7%