Revenue Analysis for Energy Storage Systems in the United States

Merve Turan and Wesley Cole

National Renewable Energy Laboratory

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Executive Summary

In this work, we evaluate the potential revenue from energy storage using historical energy-only electricity prices, forward-looking projections of hourly electricity prices, and actual reported revenue. This analysis examines the impact of storage duration and round-trip efficiency, as well as the location of the storage, on storage revenue within the current and projected U.S. power system.

Figure ES-1 illustrates the modeled revenue for a 1-megawatt (MW) storage system in seven market regions with durations ranging from 1 hour to 12 hours using historical pricing data. The historical observations cover hourly energy prices of more than 500 price nodes for each market region from 2017 to 2021. The results indicate the revenues consistently increase with duration, though the marginal value of longer duration declines as duration grows. For example, in 2021, the median revenue increases from $24.7/kW to $63.0/kW with increasing system duration from 1 hour to 6 hours whereas increasing system duration from 6 hours to 12 hours increases median revenue by around $6/kW. Additionally, the revenue ranges also widen with increased durations across years and markets, indicating that longer durations have a greater variation in value than shorter durations. For example, in 2021, the revenue range for the system with 12 hours duration is between $37 and $320/kW while the range for 1 hour storage is between $11 and $137/kW.

Figure ES-2 shows the revenue estimation for a 1 MW storage system in seven market regions with durations from 1 hour to 12 hours using forward-looking electricity prices. The price data covers hourly energy, operating reserve, and planning reserve prices for 134 regions under 10 different future scenarios of the electricity system. Similar to historical analysis, the revenues increase with duration whereas the marginal value of longer duration declines as duration grows. Moreover, the range of revenue depends on the system's operational location and the changing electricity generation mix in future years. For example, in 2050, the revenue range for 2-hour batteries in CAISO is between $103 and $207/kW while the revenue range for the same duration in ERCOT is between $67 and $106/kW. Also, the systems have the highest revenue under 100% decarbonization by 2035 while they have the lowest revenue in the low-natural-gas-price or low-renewable-energy-cost scenarios.

We also investigated the impact of round-trip efficiency on storage revenue. We found that the relationship between storage revenue and round-trip efficiency is nonlinear. The value of improved round-trip efficiency declines as round-trip efficiency increases.

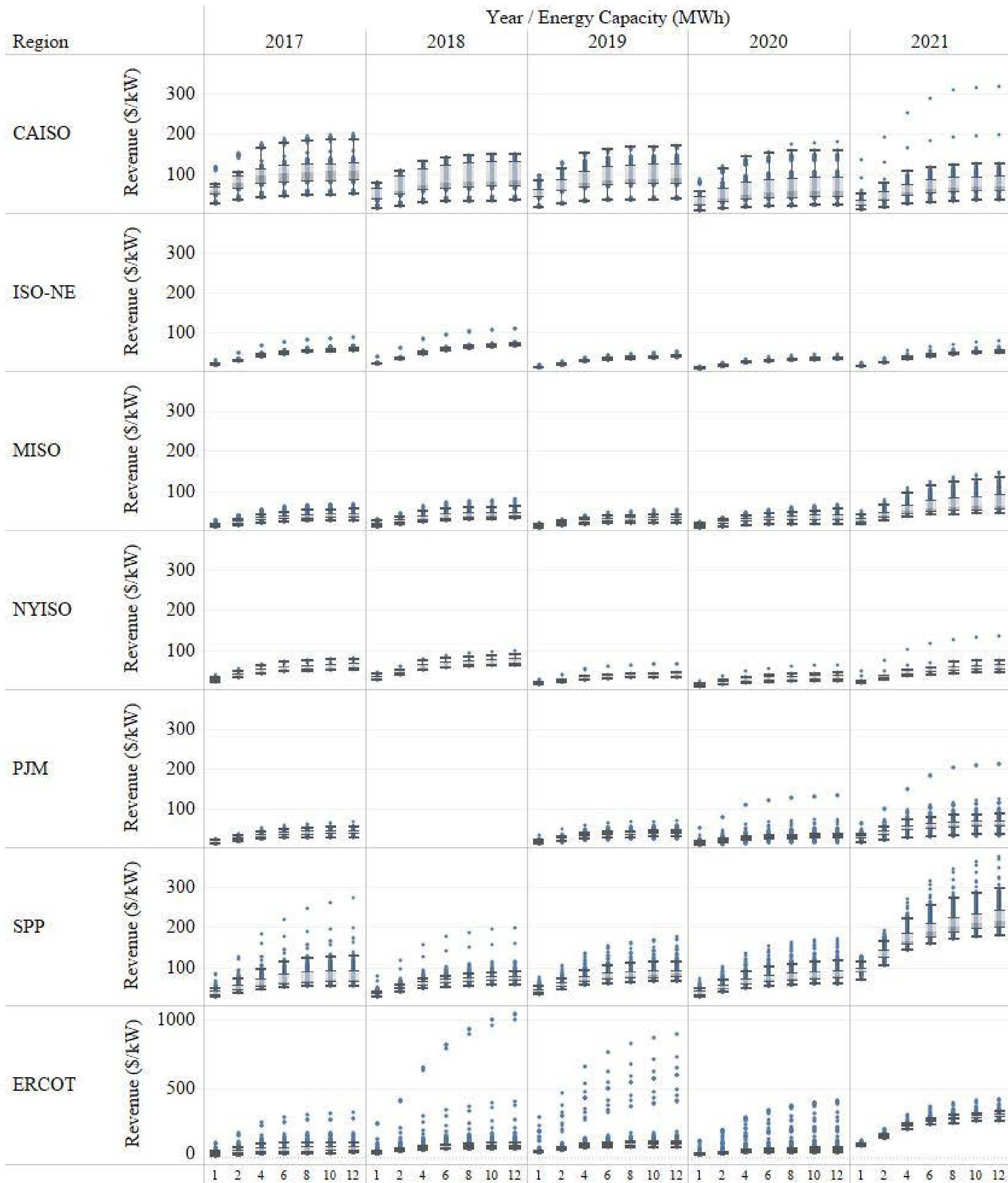

Figure ES-1. Modeled storage revenue by market region using historical energy prices from 2017 to 2021 for storage with 1-MW capacity and 75% round-trip efficiency

Energy capacity on the x-axis ranges from 1 megawatt-hour (MWh) to 12 MWh.

kW = kilowatt; kWh = kilowatt-hour; CAISO = California Independent System Operator; MISO = Midcontinent Independent System Operator; ISO-NE = New England Independent System Operator; NYISO = New York Independent System Operator; SPP = Southwest Power Pool; ERCOT = Electric Reliability Council of Texas

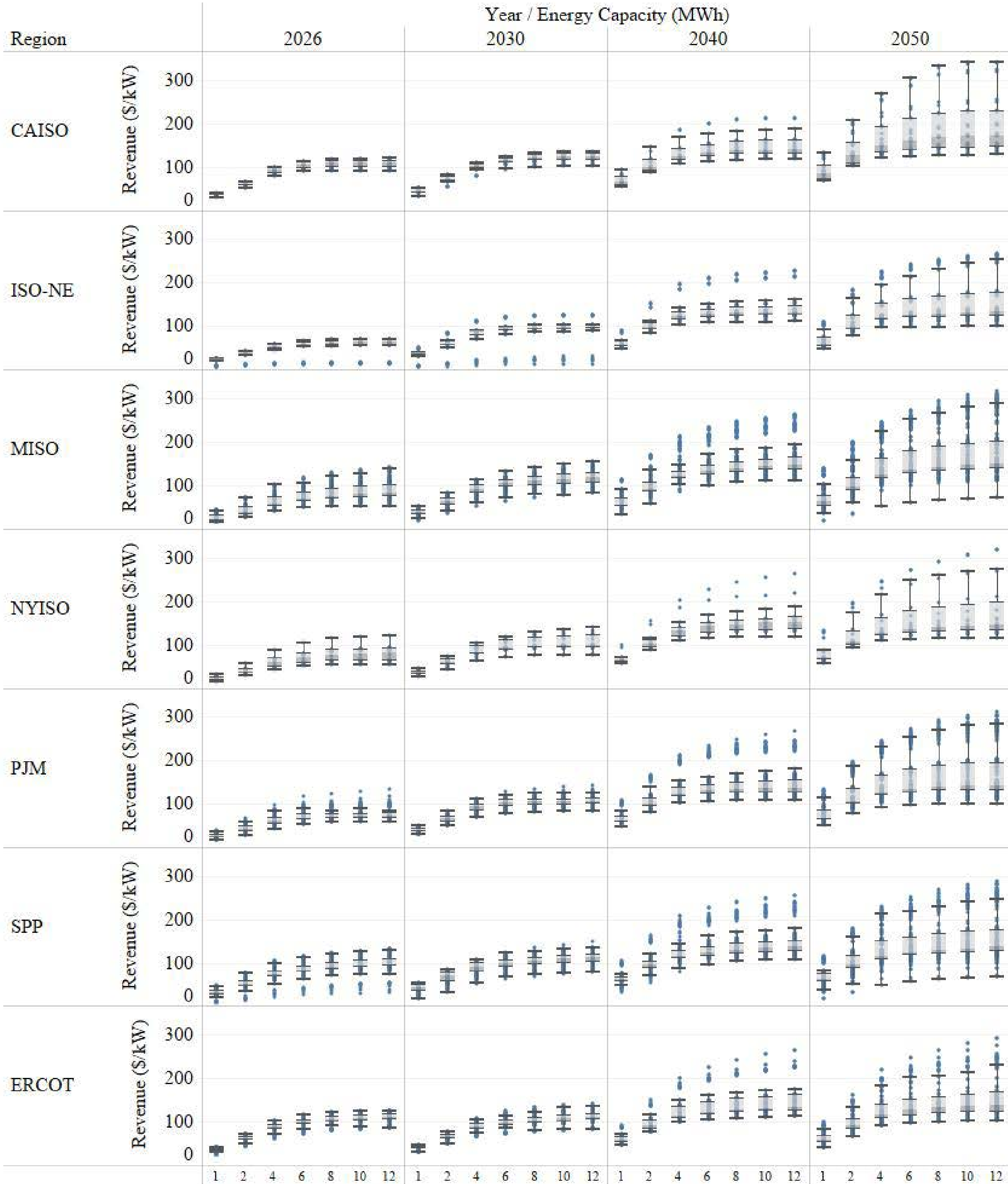

Figure ES-2. Modeled storage revenue by market region using forward-looking price estimates for 2026, 2030, 2040, and 2050 for storage with 1-MW capacity and 75% round-trip efficiency

Energy capacity on the x-axis ranges from 1 megawatt-hour (MWh) to 12 MWh.

kW = kilowatt; kWh = kilowatt-hour; CAISO = California Independent System Operator; MISO = Midcontinent Independent System Operator; ISO-NE = New England Independent System Operator; NYISO = New York Independent System Operator; SPP = Southwest Power Pool; ERCOT = Electric Reliability Council of Texas

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1 Introduction

Before 2010, nearly all energy storage in the United States was pumped storage hydropower. In the 2010s, short-duration (<1-hour) battery storage emerged to provide ancillary services. With the recent cost declines in lithium-ion batteries, large-scale lithium-ion systems have been deployed, with most new deployments having 4 hours of discharge duration since they provide energy and capacity services (Denholm, Cole, and Blair 2023). The power capacity of utility-scale battery storage systems has increased from 491 megawatts (MW) to 8,842 MW in the last 2 years (EIA 2022). Moreover, 32,466 MW of capacity is planned to be in operation by 2028 (EIA 2023b).

Interest in storage development can be gauged in part by storage interconnection requests. An interconnection request occurs when a project applies for connection to the transmission system. As of the end of 2023, there were 790,295 gigawatts (GW) of storage capacity in the queue (ignoring those with withdrawn or operational status) (Rand et al. 2024). These interconnection requests occur in all regions of the country (see Figure 1 and Table 1).

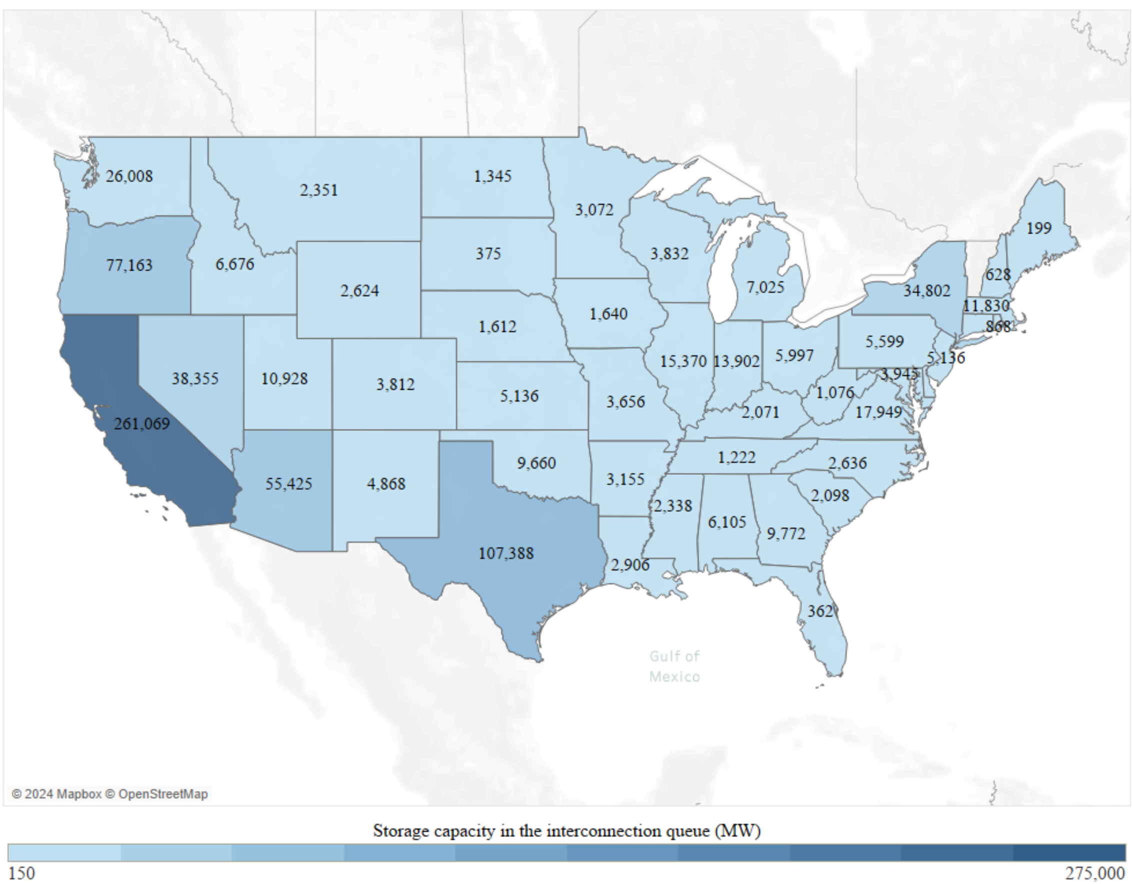

Figure 1. Storage capacity (MW) in the interconnection queue by state (Rand et al. 2024)

Withdrawn and operational projects are not included. Note that all the energy storage systems in the interconnection queue most likely won't get built.

Table 1: Storage Capacity (MW) in the Interconnection Queue by State (Rand et al. 2024)

Storage capacity is capacity listed in the interconnection queue with an active status. Withdrawn and operational projects are not included.

State	Storage Capacity (MW)	State	Storage Capacity (MW)	State	Storage Capacity (MW)
AL	6,105	MA	11,830	OH	5,997
AR	3,155	MD	3,945	OK	9,660
AZ	55,425	ME	199	OR	77,163
CA	261,069	MI	7,025	PA	5599
CO	3,812	MN	3,072	RI	868
CT	5,765	MO	3,656	SC	2,098
DE	545	MS	2338	SD	375
FL	362	MT	2,351	TN	1,222
GA	9,772	NC	2,636	TX	107,388
IA	1,640	ND	1,345	UT	10,928
ID	6,676	NE	1,612	VA	17,949
IL	15,370	NH	628	VT	-
IN	13,902	NJ	5,136	WA	26,008
KS	5,136	NM	4,868	WI	3,832
KY	2,071	NV	38,355	WV	1,076
LA	2,906	NY	34,802	WY	2,624

Long-term planning models of the U.S. power system show storage is likely to continue to grow over time. For example, the Annual Energy Outlook 2023 projects that storage capacity in 2050 will range from 64 GW to 348 GW (EIA 2023a), and the 2023 Standard Scenarios projects 150 to 600 GW of storage by 2050 (Gagnon et al. 2024).

For storage systems to continue to be deployed, they will need sufficient revenue to offset the cost of the storage system. That revenue can come from a variety of sources and take many forms (Mastropietro, Rodilla, and Batlle 2024). For this work, we evaluate the potential revenue from energy storage using historical energy prices, forward-looking projections of hourly energy prices, and historical reported revenue. This analysis helps show the trends, revenue ranges, and locational elements of storage revenue in the current and projected U.S. power system.

2 Methods for Revenue Analysis

This study examines the potential revenue of energy storage systems, using both historical reported revenue data and price-taker analysis of historical and projected future prices. To achieve this, we collected price and revenue data and implemented a price-taker model to determine annual revenue, which is explained in the following sections.

2.1 Data Collection and System Assumptions

To analyze reported revenue, we used data reported by the Federal Energy Regulatory Commission (FERC). FERC provides quarterly total transaction charges in its Electric Quarterly Reports (EQR),[1] categorized by product types such as energy, capacity, or regulation and frequency response. The data are provided at an aggregated level without specific information about the types of generators the reporting data covers. However, to capture power plants that are likely to be storage facilities, we extracted any company with "energy storage" in the name, which resulted in 29 facilities. We cross-checked these company names with EIA's preliminary monthly electric generator inventory to obtain location and energy and power capacities for the specific facilities. Facilities' durations are calculated based on the ratio of power capacity to energy capacity

For price-taker analysis using historical energy prices, we used real-time hourly energy price data from the ABB Locational Marginal Pricing database. The data cover energy prices from 2017 to 2021 across multiple nodes in seven market regions: California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), Independent System Operator of New England (ISO-NE), New York Independent System Operator (NYISO), PJM, and Southwest Power Pool (SPP). To manage data volume and price-taker model runs, we limited the number of nodes in each market region to 500. In regions with fewer than 500 nodes, we used the full set of available nodes. For regions with more than 500 nodes, we applied a selection process: We first calculated statistical values (maximum, minimum, average, and standard deviation) for each price node over 5 years, removed nodes with identical statistical values, and removed nodes that were missing many observations. If the remaining nodes still exceeded 500, we selected the nodes that had maximum and minimum absolute price points, the maximum and minimum average prices, and the maximum and minimum standard deviation. The remaining nodes were randomly chosen until we had a total of 500 for that market region.

Importantly, these historical prices reflect the price formation rules in each market region and are only the energy price. If a market region also has a capacity market or bilateral capacity payments, that revenue would not be captured in the price-taker analysis using those historical prices.

For forward-looking price-taker analysis, we obtained price data from the Cambium Database (Gagnon, Cowiestoll, and Schwarz 2023). The data contain hourly energy, operating reserve, and planning reserve prices for 134 model regions of the contiguous United States. We extracted data for 4 years—2026, 2030, 2040, and 2050—under 10 scenarios. These 134 model regions are

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[1] The data are obtained from https://www.ferc.gov/power-sales-and-markets/electric-quarterly-reports-eqr.

matched with 9 regions as shown in Figure 2. The Cambium scenarios include factors such as Inflation Reduction Act incentives, alternative natural gas prices (low and high natural gas prices), alternative renewable energy costs (low and high renewable energy costs), carbon policies (95% reduction in CO_2 emissions by 2050 or net zero emissions by 2035), and electrification. The average price is highest under the net zero emissions by 2035 and lowest under the low-natural-gas-price scenario.

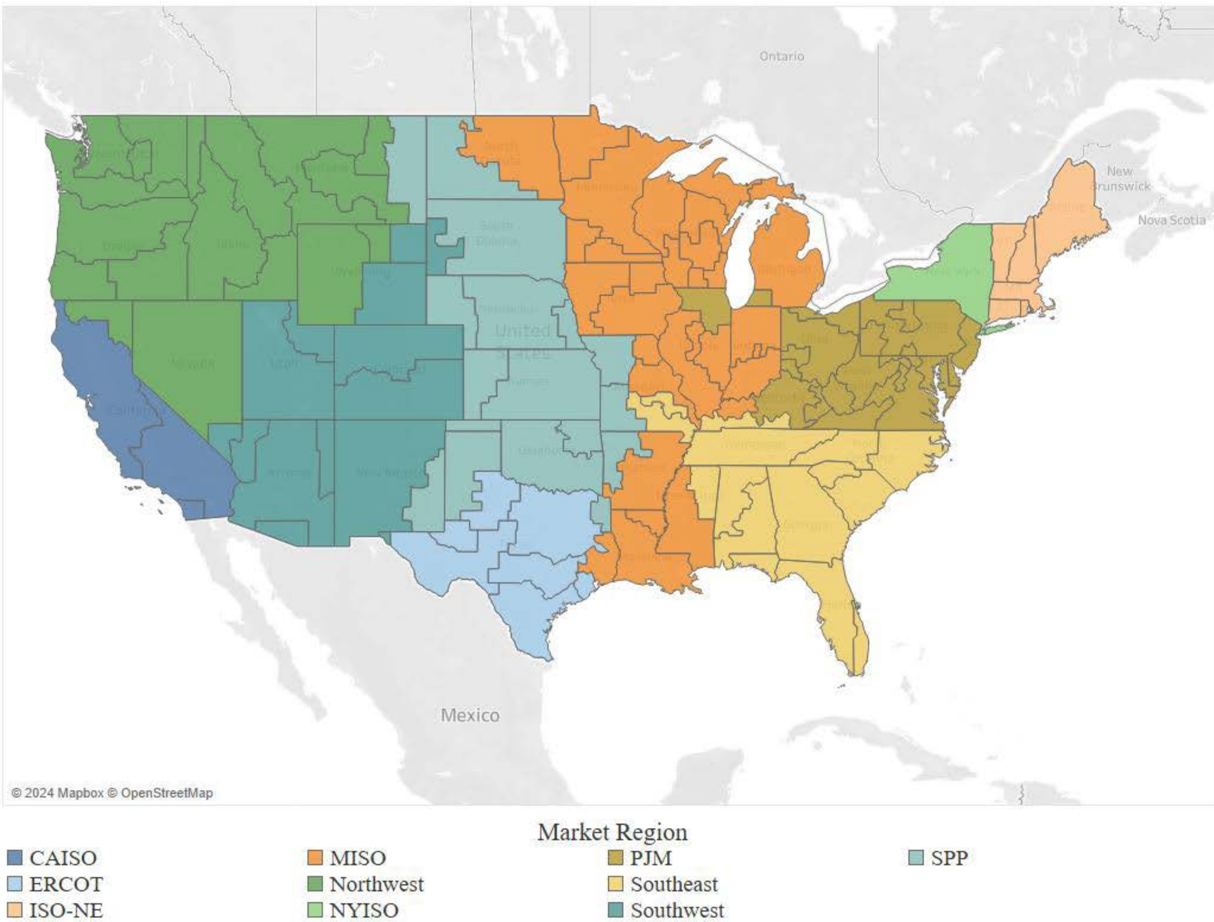

Figure 2. Map of model regions and market regions

Colored polygons represent market regions; subpolygons represent model balancing areas inside the market region.

In summary, we collected data that allowed us to conduct three distinct revenue analyses:

- Reported revenue using data reported to FERC for 2014–2023 for a small sample of storage facilities
- Energy-only electricity price arbitrage revenue using actual reported hourly electricity prices from 2017 to 2021 for up to 500 nodes in each market region
- Bulk electricity price arbitrage revenue for the 134 model regions in the Cambium dataset from 2026 to 2050.

2.2 Modeling Framework

The price-taker model provides operational decisions for energy storage systems by considering wholesale electricity prices over a given period. This model assumes that the system does not influence market prices. As a result, the price-taker model is commonly used in revenue analysis for single battery systems. In the literature, price-taker models account for the system's characteristics, such as energy and power capacity, while market participation of storage can vary. For example, some models consider only energy market participation (Sioshansi et al. 2009; McConnell, Forcey, and Sandiford 2015; Adebayo et al. 2018; Arcos-Vargas, Canca, and Núñez 2020; Zafirakis et al. 2016; Connolly et al. 2011; Brijs et al. 2019), while others include ancillary market participation as well (Kazempour et al. 2009; Yu and Foggo 2017; Chazarra, Pérez-Díaz, and García-González 2014; Staffell and Rustomji 2016; Pinto, de Sousa, and Neves 2011; Drury, Denholm, and Sioshansi 2011; Berrada, Loudiyi, and Zorkani 2016; Moreno, Moreira, and Strbac 2015; Guerra Fernandez et al. 2020).

In this study, we use the Revenue, Operation, and Device Optimization (RODeO) model, a price-taker revenue optimization model to maximize the net revenue for storage in a given region and period (Guerra Fernandez et al. 2020). Using hourly electricity market data and technology characteristics, RODeO determines optimal hourly charging and discharging schedule and magnitude with perfect foresight over the course of a year. For instance, Figure 3 shows an example output from RODeO for a 1-MW, 4-megawatt-hour (MWh) storage system in response to electricity prices. As shown in the figure, the storage system will charge when prices are lowest and then discharge when prices are highest to maximize revenue. The storage revenue is calculated by summing the charging cost and discharging revenue over all hours of the year. Charging cost is the payment of storage to purchase power from electricity market, calculated by multiplying electricity purchase price with input power. Discharging revenue is the revenue generated from selling power to the market calculated by multiplying electricity purchase price with output power.

For both the historical and forward-looking price-taker analyses, we assumed a 1-MW power capacity and varied the duration from 1 MWh to 12 MWh with 1-MWh increments. We normalize revenue results by capacity, so this power capacity assumption is irrelevant. In additionally, we assume storage round-trip efficiency is 0.75 for historical and forward-looking revenue analyses. We also conduct sensitivity analysis for round-trip efficiency from 0.35 to 0.85 with 0.10 incrementation and from 0.68 to 0.78 with 0.02 incrementation.

Importantly, because we are taking a price-taker approach, the revenue calculations from RODeO assume the storage behavior will not impact the electricity price at a given node

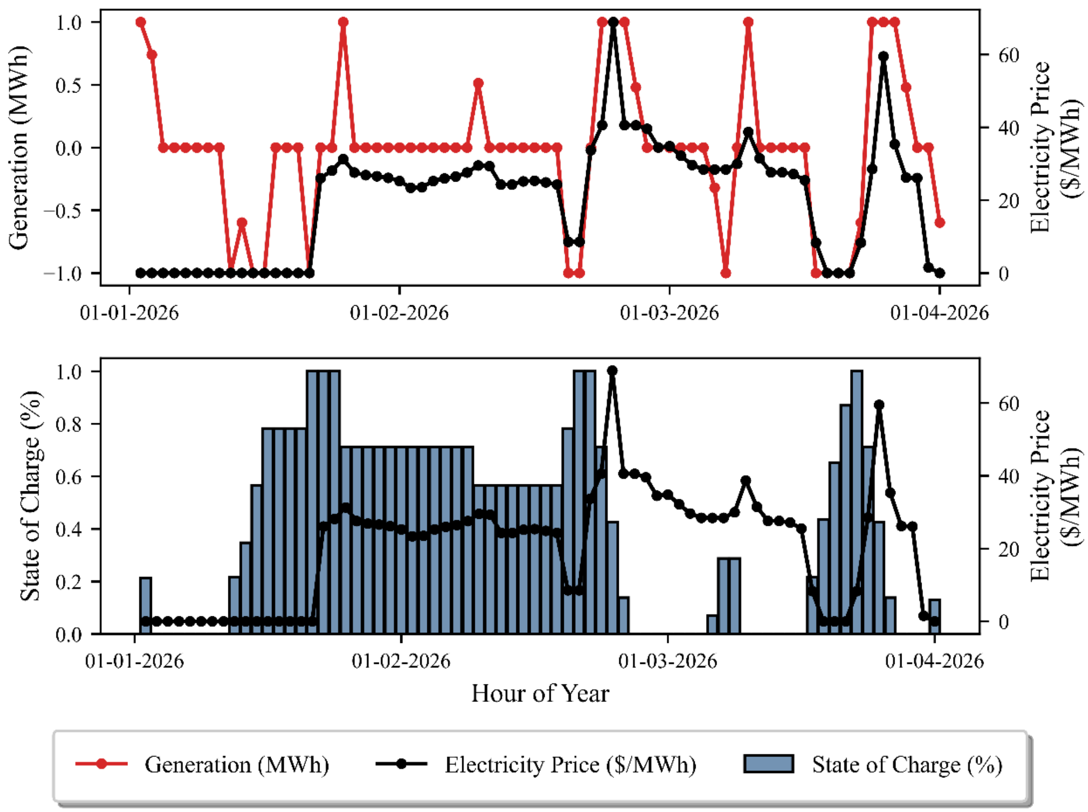

Figure 3. Storage dispatch (top) and state of charge (bottom)

In both cases, the electricity price is shown on the right axis.

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3 Results

We present results for the three datasets that we have assembled for this work. First, we present the results for the reported energy storage revenue based on the data provided by FERC. Next, we show the revenue calculations based on historical real-time electricity prices. Finally, we present the revenue calculations based on the future projected bulk system electricity prices. Note that, the historical revenue analyses consider only energy market price. In Appendix A, the revenue analysis for energy storages that participate in energy market or both energy and ancillary services market for CAISO is explained.

3.1 Reported Energy Storage Revenue

Figure 4 and Figure 5 show the reported revenue for energy storage systems from the FERC dataset. The figures break out the source of the revenue based on the reporting to FERC into energy, capacity, regulation & frequency response, spinning reserve, energy imbalance, uplift, and booked out power.[2] Because the online date for these systems is typically late in the year, the revenue in the first year can be lower because of less online time in that year. Similarly, year-to-year fluctuations in revenue can be a function of facility level operations, total uptime, and electricity prices.

These year-to-year fluctuations can be substantial for some systems. This can best be seen by Beech Ridge Energy Storage in PJM (Figure 4) and Venture Energy Storage in SPP (Figure 5). Other systems can have revenues that stay fairly constant, such as Pima Energy Storage and VESI Pomona Energy Storage in SPP (Figure 5). Most storage systems, however, are too recent to be able to understand why or where there might be interannual revenue variation.

These figures also highlight differences in the total reported revenue of energy storage. In CAISO, most systems report annual revenues of $200/kW or less (Figure 4), and in SPP some systems have annual revenues greater than $400/kW (Figure 5). Based on current estimates for battery costs (W. Cole and Karmakar 2023) and financing costs from the 2023 Annual Technology Baseline (National Renewable Energy Laboratory 2023), 4-hour storage with a 30% investment tax credit would need to collect around $185/kW annually to break even, and 2-hour storage would need to receive about $110/kW annually.

[2] The definitions of market products are in https://www.ferc.gov/sites/default/files/2020-05/EQRdata-dictionary.pdf

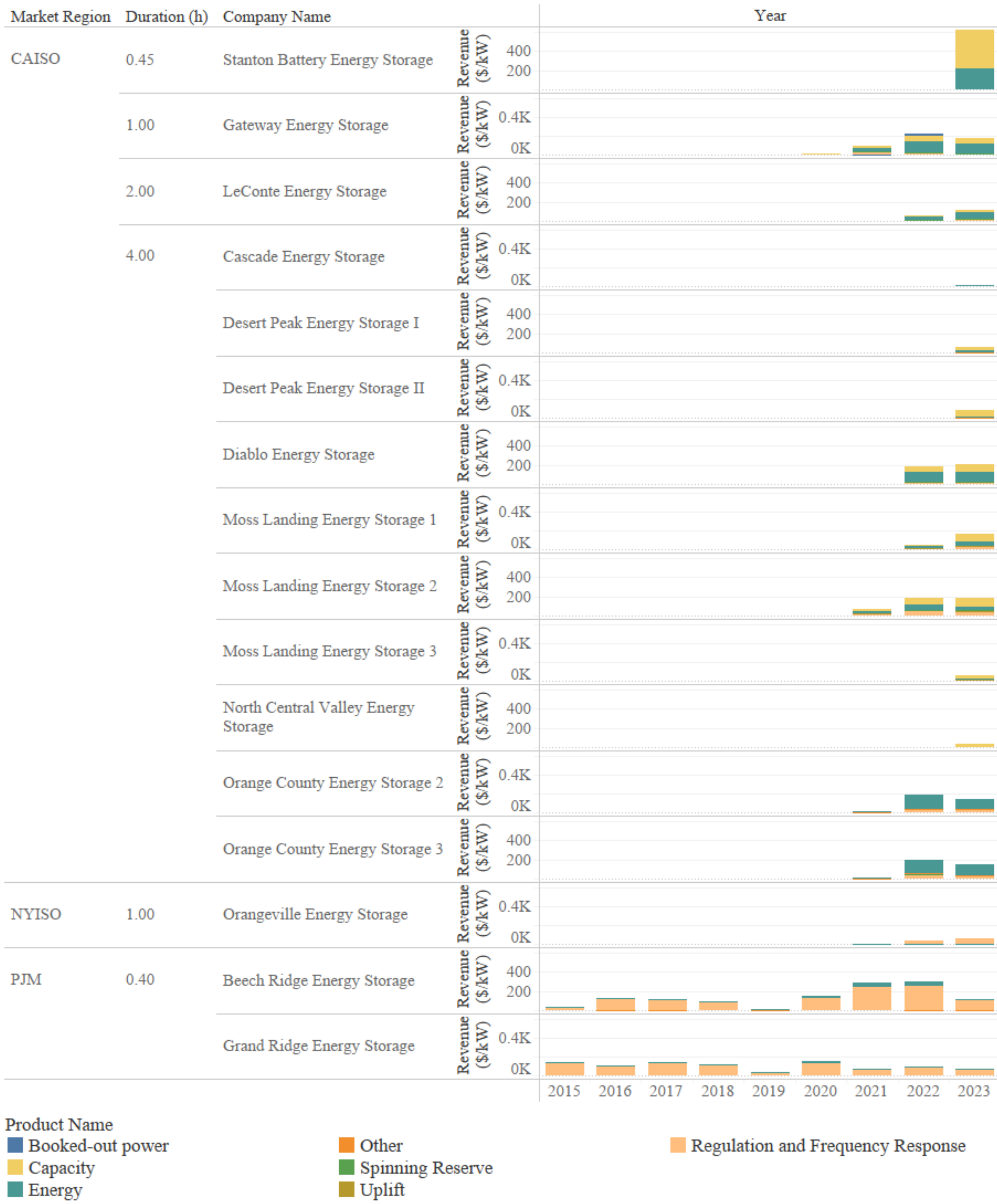

Figure 4. Reported revenue normalized by system capacity for energy storage companies in CAISO, NYISO, and PJM

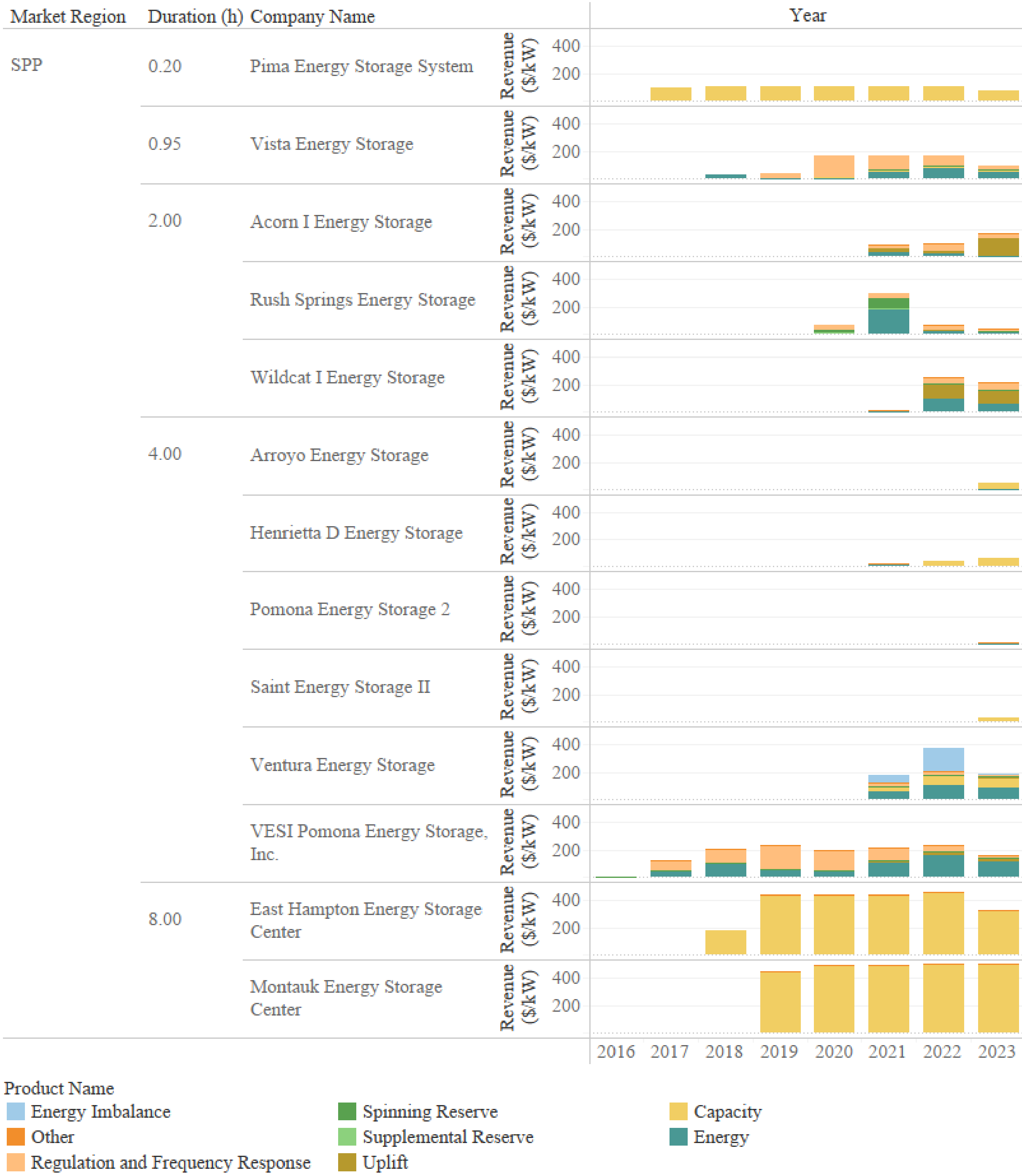

Figure 5. Reported revenue normalized by system capacity for energy storage companies in SPP

Figure 6 shows the share of total reported revenue by revenue type. For all durations of 2 hours or more, the portion of revenue from regulation and frequency response is relatively small. Energy and capacity make up the largest share of revenue for those durations, with the longer durations generally seeing a greater share of revenue from capacity than the shorter durations. For the shorter durations, the share of revenue depends on market region. In NYISO and PJM, the short-duration devices are getting all or most of their revenue from regulation and frequency response.

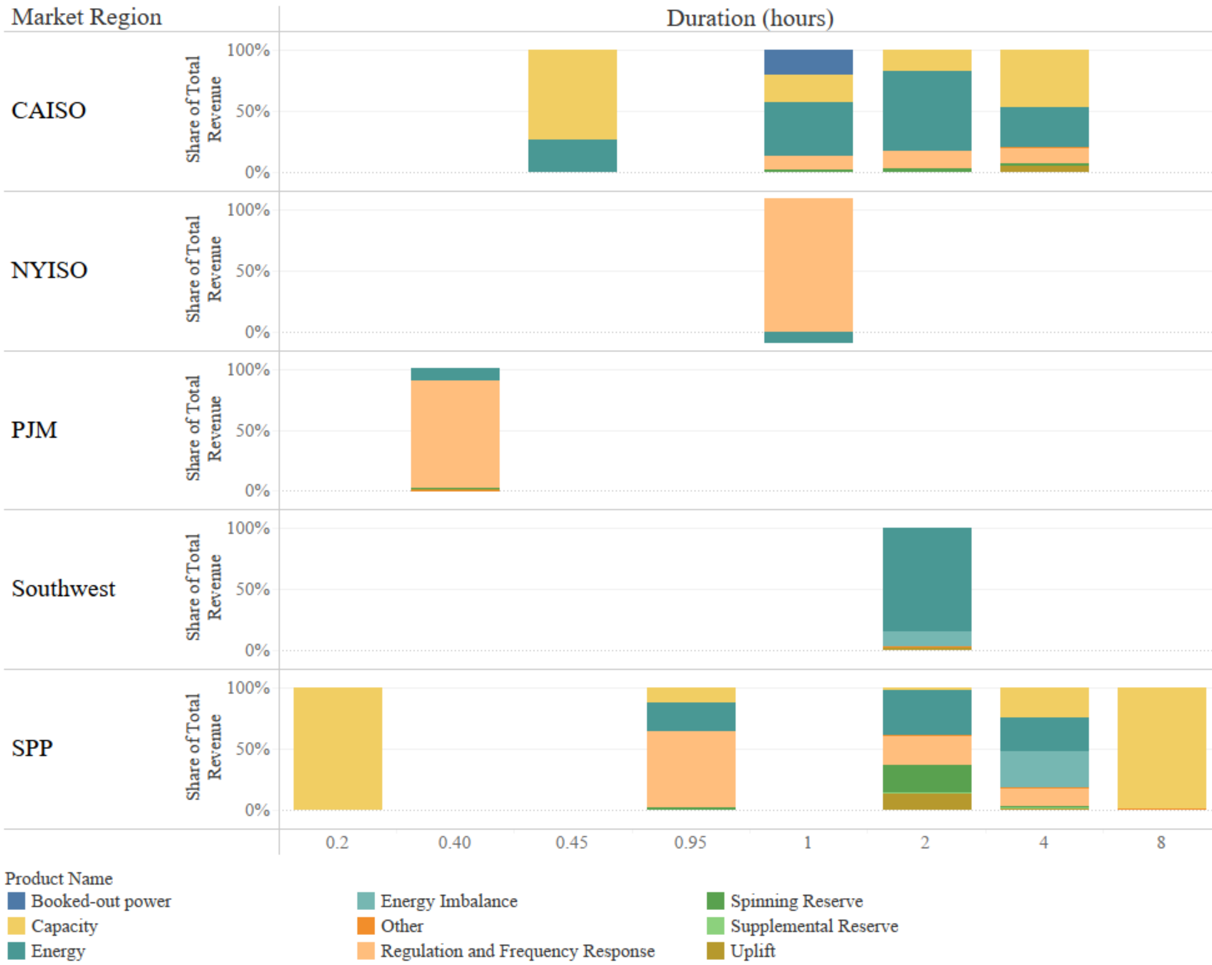

Figure 6. Share of total reported revenue by duration and market region

3.2 Revenue Analysis Using Historical Pricing Data

Figure 7 and Figure 8 show the modeled revenue for storage for each year, duration, and market region. Figure 7 includes the regions with the highest nodal revenues, and Figure 8 shows the regions where nodes never had more than $200/kW of revenue in a given year. Note that, Figure 7 and Figure 8 illustrate varied the duration of 1, 2, 4, 6, 8, and 12 MWh whereas the modeled revenues for complete set of durations are in Appendix B. ERCOT shows the wide range in modeled revenue, with some individual nodes reaching values of more than $1,000/kW in 2018—particularly driven by higher standard deviations in both positive and negative prices, which highlight nodes with the highest value. This wide variation in modeled revenue at the different nodes highlights the importance of siting a storage resource at a more attractive node because the revenue potential can be approximately an order of magnitude different between the “best” and “worst” nodes.

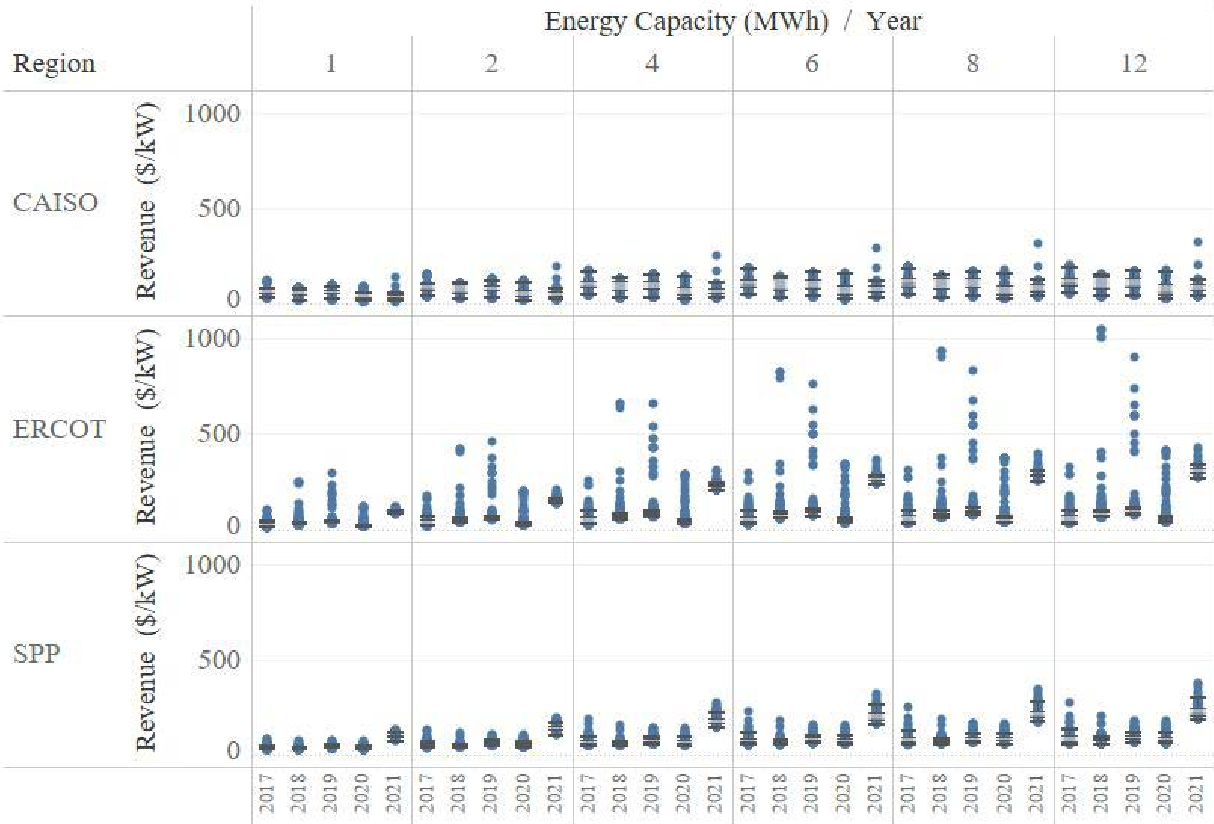

Figure 7. Modeled revenue using nodal pricing data from 2017 to 2021 for CAISO, ERCOT, and SPP for a 1-MW system

Importantly, because these revenues are calculated using a price-taker modeling approach, it is not clear how much storage can be added to a node before the revenue potential erodes. For example, if the highest price node in ERCOT is driven by 10 MW of congestion, adding more than 10 MW of storage will alleviate that congestion and might substantially lower potential storage revenue at that node.

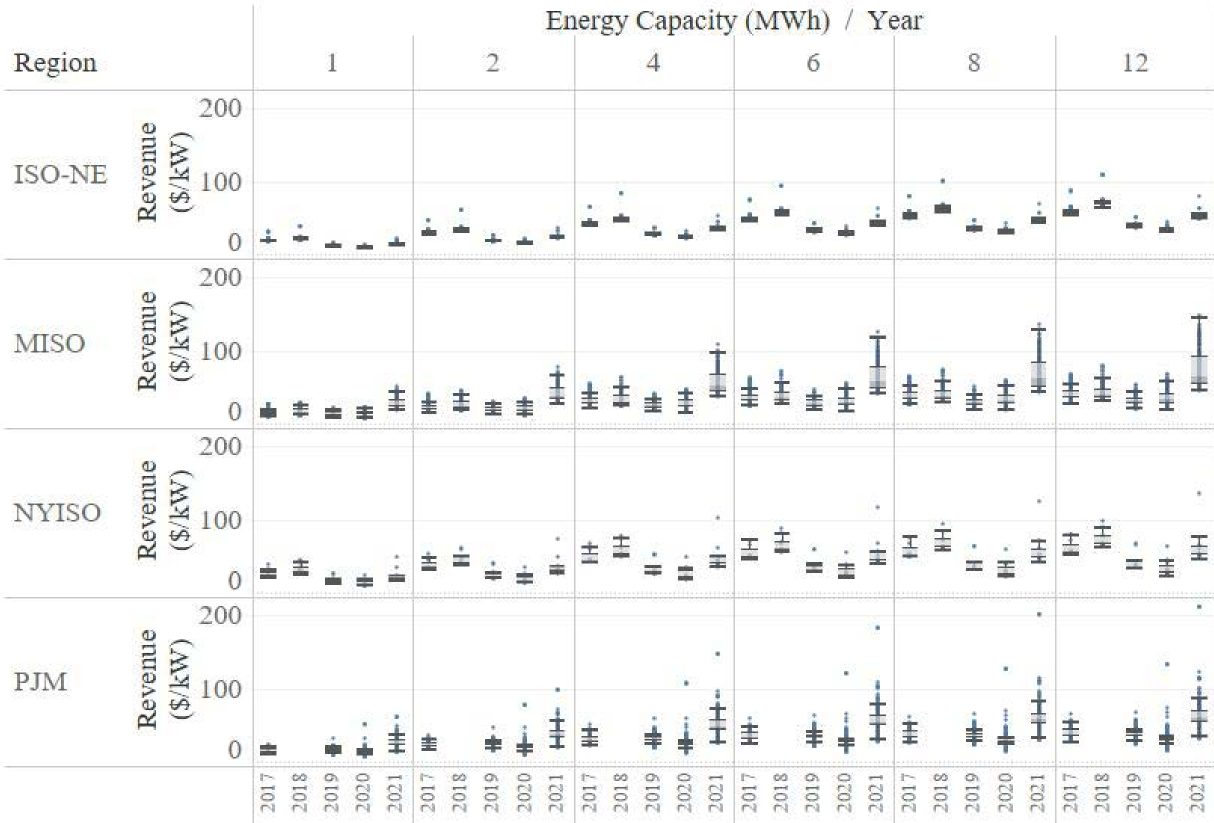

Figure 8. Modeled revenue using nodal pricing data from 2017 to 2021 for MISO, ISO-NE, NYISO, and PJM for a 1-MW system

The interannual variability in modeled revenue can be significant, with some years more than doubling the revenue of other years. All the regions (MISO, ISO-NE, NYISO, and PJM) in Figure 8 show similar temporal patterns (same highest and lowest years), and SPP and ERCOT show some correlation in revenues. Revenues for CAISO are unique from the other regions.

Modeled revenues always increase with duration, though the rate of increase declines as duration grows. This is shown more clearly in Section 3.3.

Figure 9 shows the historical modeled revenue data with the reported revenue data to highlight similarities and differences. Importantly, the historical modeled revenue data use only energy prices whereas the reported revenue data include revenue from many other services—including capacity and ancillary services. In general, reported revenue values from FERC are aligned with the modeled energy revenue but in some cases can be higher, such as in SPP.

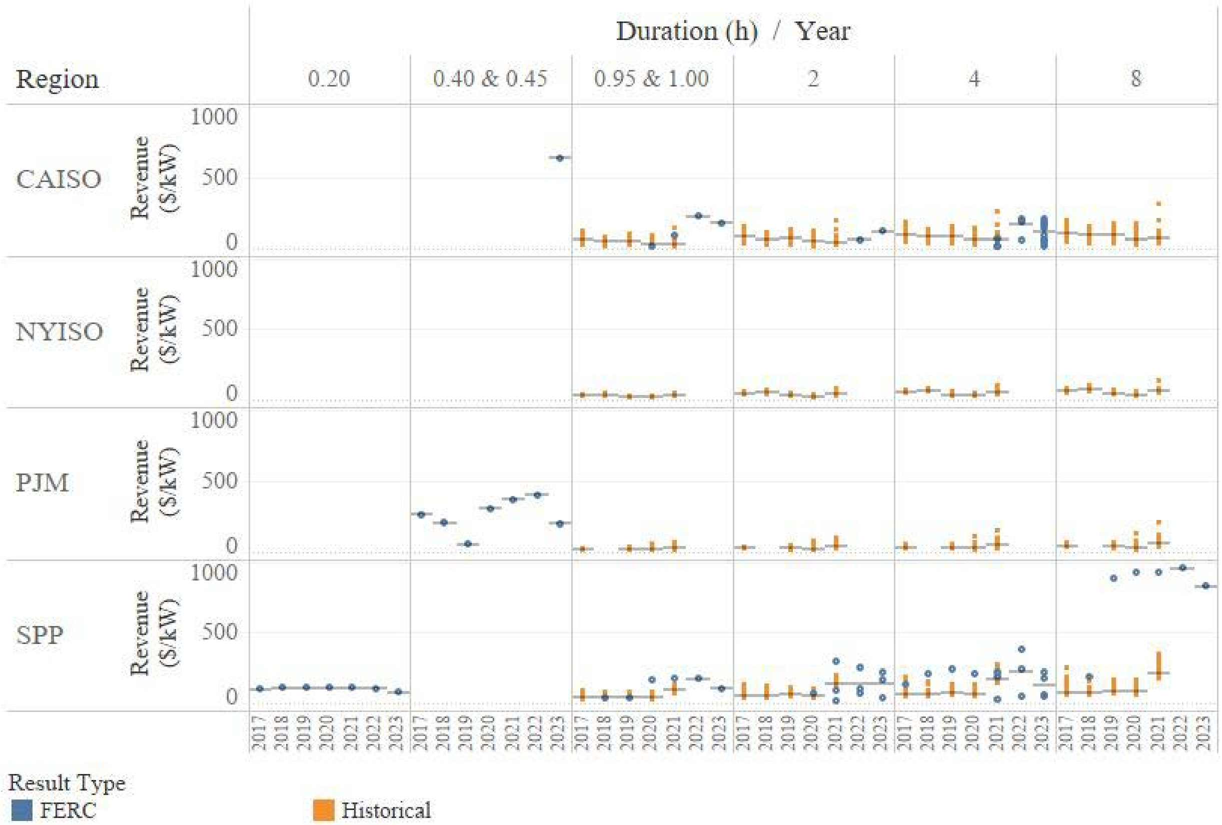

Figure 9. Comparison of reported revenue (FERC) with historical modeled revenue (historical)

The storage duration is shown in the columns.

In organized electricity markets, payments for capacity are partially or fully included in the energy prices via scarcity pricing mechanisms. ERCOT has an energy-only market, and capacity revenues are manifested through very high energy prices (up to $9,000/MWh in some of the historical datasets and currently up to $5,000/MWh). In other markets, a separate capacity market provides additional revenue for the capacity value of generation and storage assets.[3] In CAISO, there is a bilateral market for system capacity, and recent prices for those trades are summarized in Table 2. In other regions, there is a formal capacity market, and capacity prices are set based on the bids and market rules for that region. In ISO-NE, the most recent forward capacity auction (for the 2027/2028 year) cleared at $42.96/kW-yr, and clearing prices have ranged from as low as $35/kW-yr to as high as $213/kW-yr.[4]

[3] Not all capacity revenue will come through the capacity markets. Most markets have some level of scarcity pricing that will provides revenues for capacity, though the extent to which capacity revenue occurs in the energy market versus the capacity market is driven by market rules and the analyst's definition of where energy payments end and capacity payments begin.

[4] See https://www.iso-ne.com/about/key-stats/markets#fcaresults. The prices on the high end are for specific regions and generator vintages.

Table 2. System Capacity Prices in CAISO in 2021, 2022, and 2023 as Reported by Load-Serving Entities (S. Cole et al. 2023)

Values are in $/kW-yr.

Year	*Average*	*85th Percentile*
2021	78.00	108.00
2022	78.48	96.00
2023	76.20	90.48

In most markets, 4 hours of storage is necessary to receive the full capacity payment. Durations less than 4 hours would be given a fractional amount equal to their discharge capability. For example, a 1-hour storage device could discharge at 25% capacity for 4 hours and so would receive 25% of the capacity payment. That also means durations greater than 4 hours would not receive any additional capacity revenue. Figure 10 shows this relationship using the 2021 CAISO prices from Table 2.

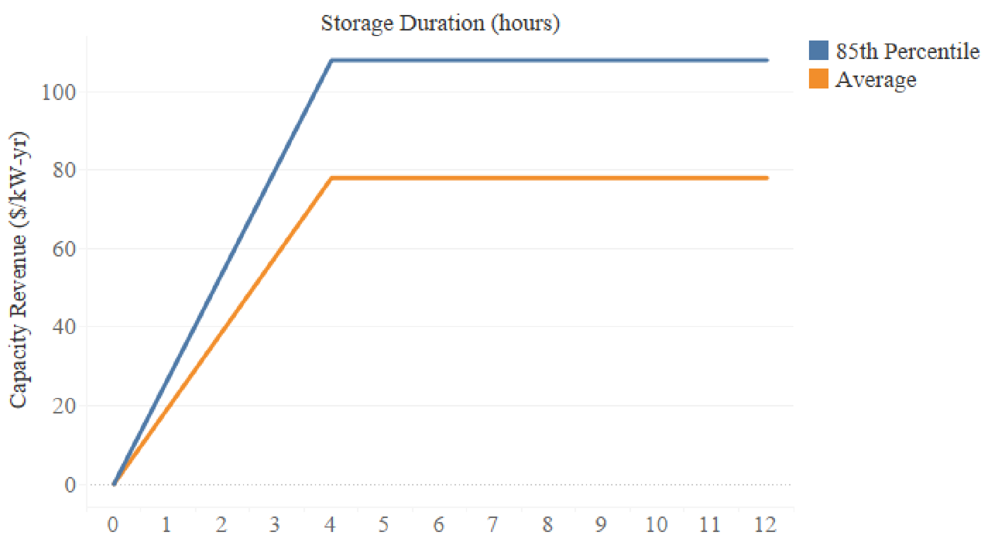

Figure 10. Capacity revenue by duration for CAISO in 2021 for the prices from Table 2

The minimum, average, and maximum energy revenue values for CAISO for 2021 are shown in Figure 11 (these values are included in the larger subset shown in Figure 7). The combined energy and capacity revenue is shown in Figure 12. These plots demonstrate the value of longer durations, though with a noticeable change in value growth after 4 hours because of maximum capacity revenue being reached at 4 hours.

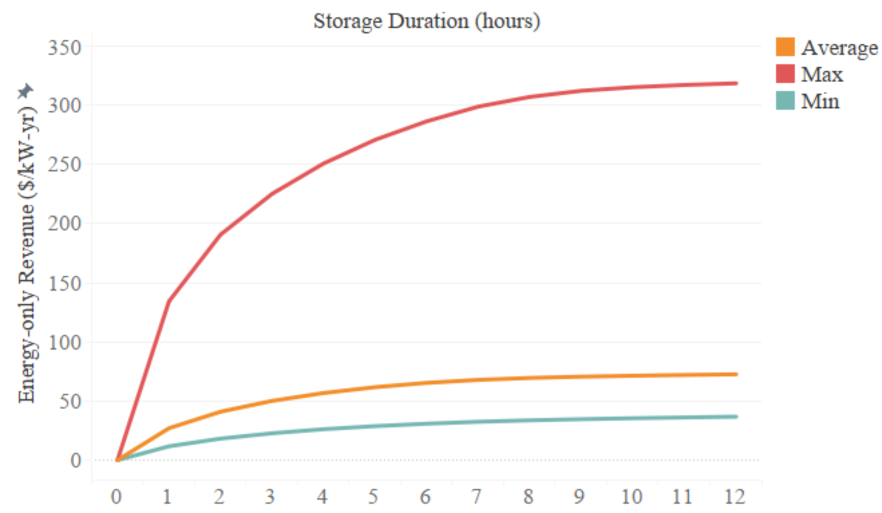

Figure 11. Energy-only revenue by duration for CAISO in 2021 for the minimum, maximum, and average nodes

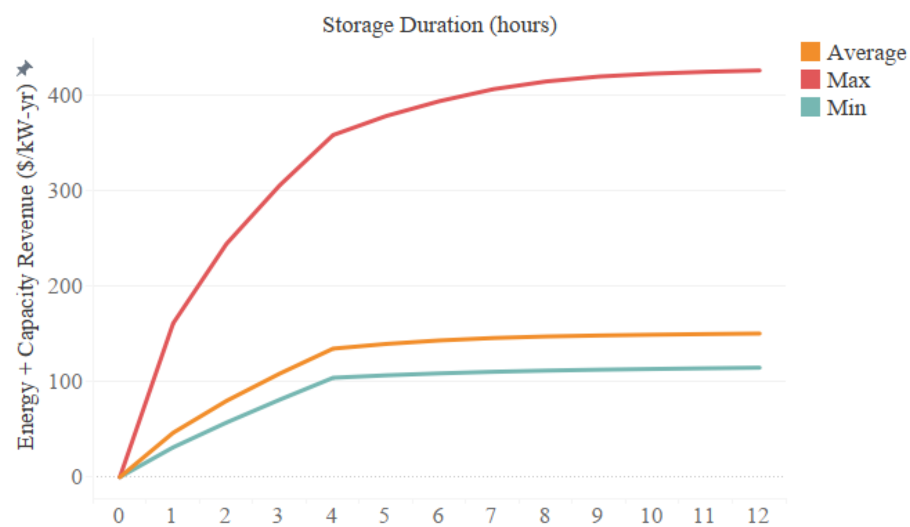

Figure 12. Energy plus capacity revenue for CAISO in 2021 for the minimum, maximum, and average nodes

The minimum and average nodes use the average capacity revenue values from Figure 11 whereas the maximum node uses the 85th percentile revenue values from Figure 11.

Because of the higher revenues at longer durations, some storage operators might consider operating their storage device as if it were a longer-duration unit to try to capture some of these higher revenues. However, unless the operation of the storage impacts the prices, the longer-duration operation mode would not be able to increase revenue. For example, considering the average revenue line in Figure 12, the 2-hour revenue amount is $79.93/kW-yr and the 4-hour revenue amount is $134.74/kW-yr. If the 2-hour device were to operate like a 4-hour device, it would be operating at half capacity (e.g., a 10 kW/20 kWh device would discharge at 5 kW to operate for 4 hours). Therefore, it would receive half of the revenue that a 4-hour device receives, or ½ * $134.74/kW-yr = $67.37/yr. This amount is less than the $79.93/kW-yr it would receive if it operated as a 2-hour device. Said another way, the slope of the revenue curve (Figure 12) is always declining, which means it is impossible to capture more revenue from operating as a longer-duration device (again, assuming the storage behavior does not impact the electricity price).

3.3 Revenue Analysis Using Forward-Looking Modeled Prices

Figure 13 and Figure 14 show the modeled revenue using the forward-looking electricity prices from the Cambium dataset, including energy, capacity, and ansillary service prices. Unlike the historical nodal datasets, future prices from Cambium are estimated under a changing electricity generation mix for 134 modeled areas.. Figure 13 reports the data for the market regions and shows the revenue using the historical prices data from Section 3.2 alongside the forward-looking estimates. Because there are no market data for the nonmarket regions, only the forward-looking data are presented in Figure 14.

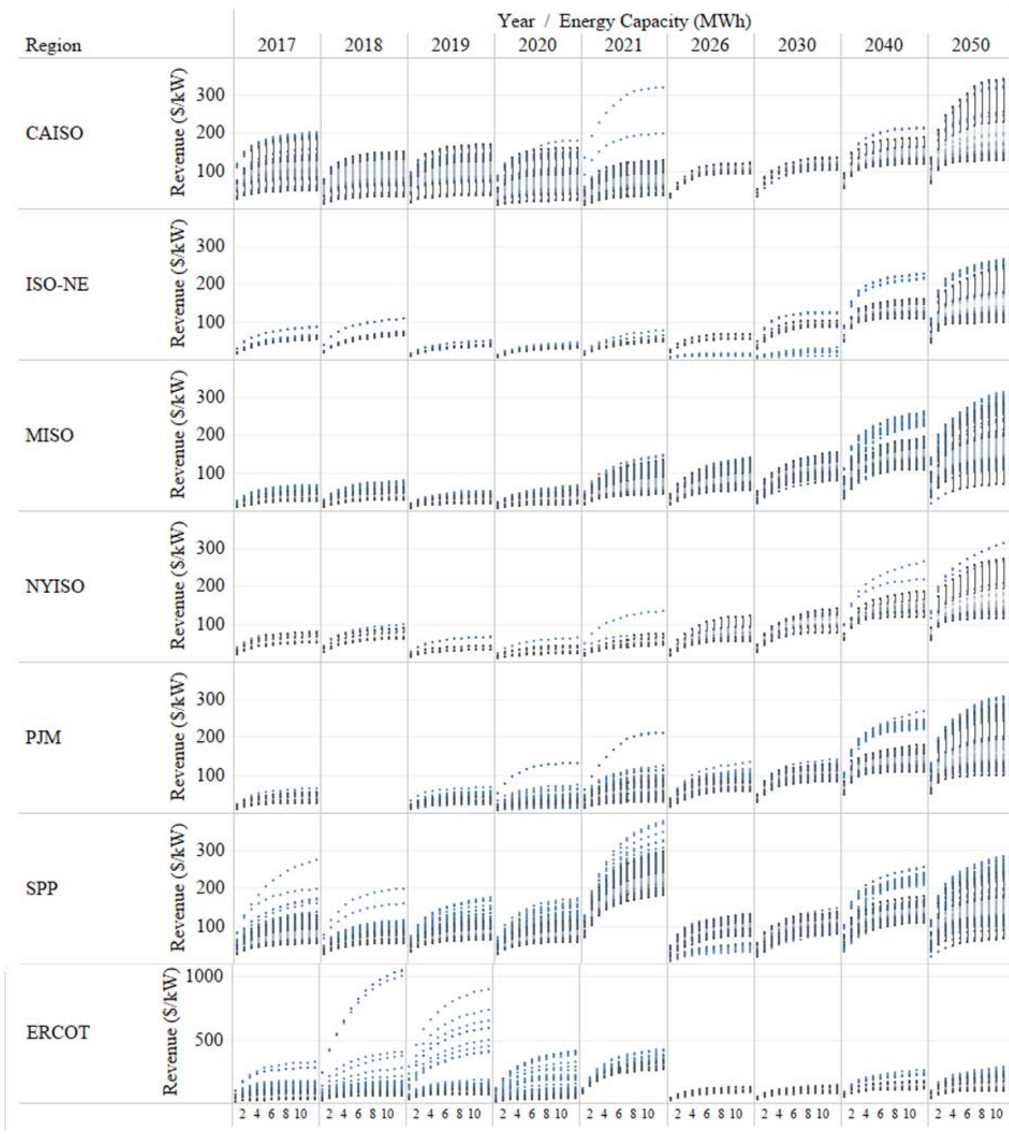

Figure 13. Revenue analysis results by energy capacity for the storage with 1-MW capacity

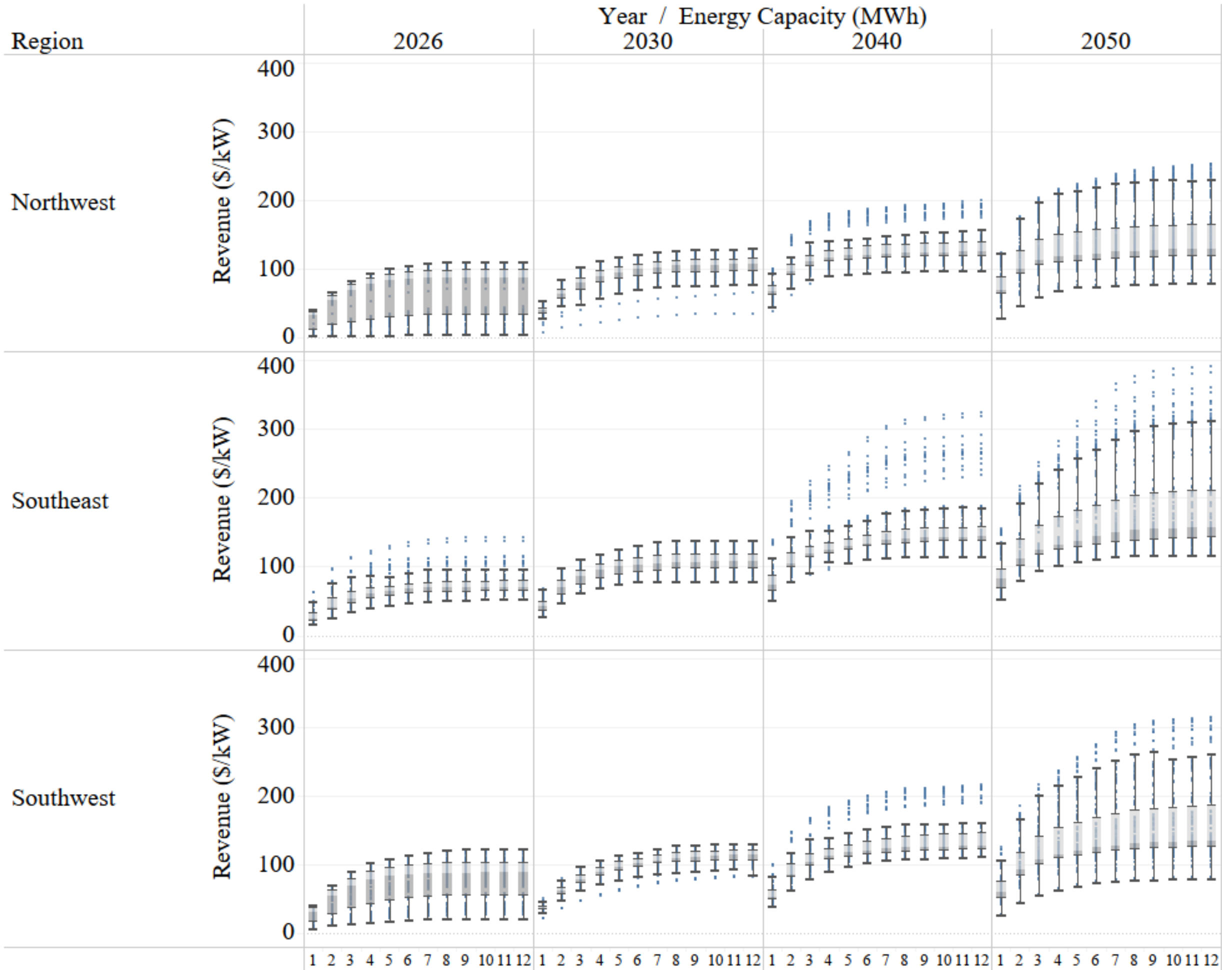

Figure 14. Revenue analysis results by energy capacity for the storage with 1-MW capacity

In all market regions, revenues increase with duration, but they do so at a declining rate. The largest increase in revenue is always from 1-hour duration to 2-hour duration and the smallest is always from 11 to 12 hours of duration. This happens because the first units of storage can always capture the most valuable arbitrage opportunities whereas longer durations naturally arbitrage lower-value opportunities because the highest ones have already been taken.

As with the revenue calculated using historical pricing, there are wide ranges of revenue in the forward-looking revenue calculations. For example, in the Southeast in 2050 (Figure 14), the revenue ranges from around $100/kW for 12-hour storage to nearly $400/kW. This variation is primarily driven by the differences in the scenario assumptions, such as the amount and types of generators present in 2050, the marginal costs of thermal units, and the amount of storage on the system. For all market regions, the storage systems have the highest revenue under the 100% decarbonization by 2035 scenario and the lowest revenue under the low-natural-gas-price or low-renewable-energy-cost scenarios.

Moreover, the revenue range widens with increasing system duration within each market region and year. For instance, in the Southeast in 2050 (Figure 14), the gap between maximum and minimum revenue is nearly \$100/kW for 1-hour storage and expands to \$300/kW for 12-hour storage. This growth in the range shows the electricity generation mix changes increase its effect on revenue analysis as system duration increases.

3.4 Impact of Round-Trip Efficiency

Figure 15 illustrates the sensitivity analysis for round trip efficiency (RTE), ranging from 0.35 to 0.85 with a 0.10 incrementation and from 0.68 to 0.78 with a 0.02 incrementation, on revenue for west Texas in 2026 (left) and 2050 (right) under a business-as-usual scenario using the forward-looking Cambium data. This analysis is conducted for 1-MW storage with energy capacity from 1 MWh to 12 MWh. As explained in Section 3.3, system revenue increases with system duration; however, the marginal revenue of energy capacity decreases regardless of round-trip efficiency. The results also indicate improving system efficiency increases revenue. For most durations and efficiencies, an increase of 1 percentage point of efficiency leads to less than a 1% increase in revenue.

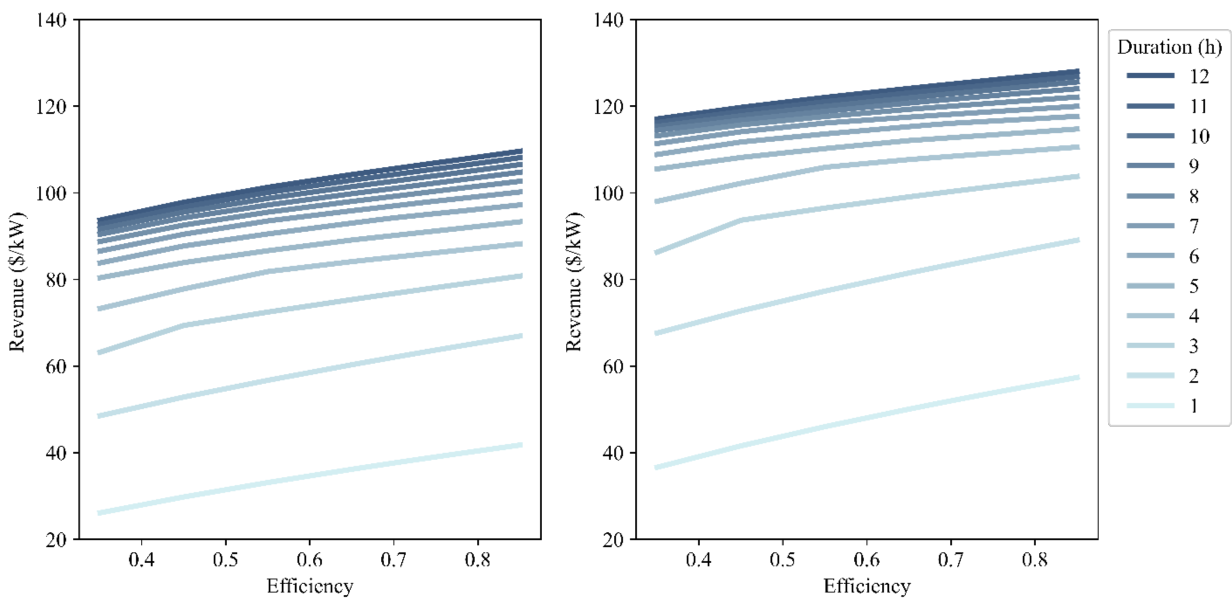

Figure 15. Impact of round-trip efficiency on revenue for west Texas in 2026 (left) and 2050 (right) for a business-as-usual scenario using the Cambium data

Figure 16 separates the discharging revenue and charging cost as a function of efficiency for 1-hr and 12-hr storage in west Texas in 2026 and 2050 under a business-as-usual scenario using the forward-looking Cambium data. The result shows that improvements in RTE increase both charging cost and discharging revenue since it increases the storage's capacity to capture revenue from arbitrage opportunities. In other words, a more efficient storage system can capture smaller arbitrage differences, allowing it to operate more frequently. Additionally, more efficient storage devices have a shorter charge/recharge time, so can operate at higher utilization rates. Notably, the charging cost is much lower in 2050 than in 2026, largely due to the buildout of more zero marginal cost resources by 2050. Those resources result in a greater number of zero-priced hours, thereby enabling lower-cost charging. And, although the marginal charging cost is higher than the marginal discharging revenue, the total storage revenue still increases because the charging cost is relatively smaller than discharging revenue.

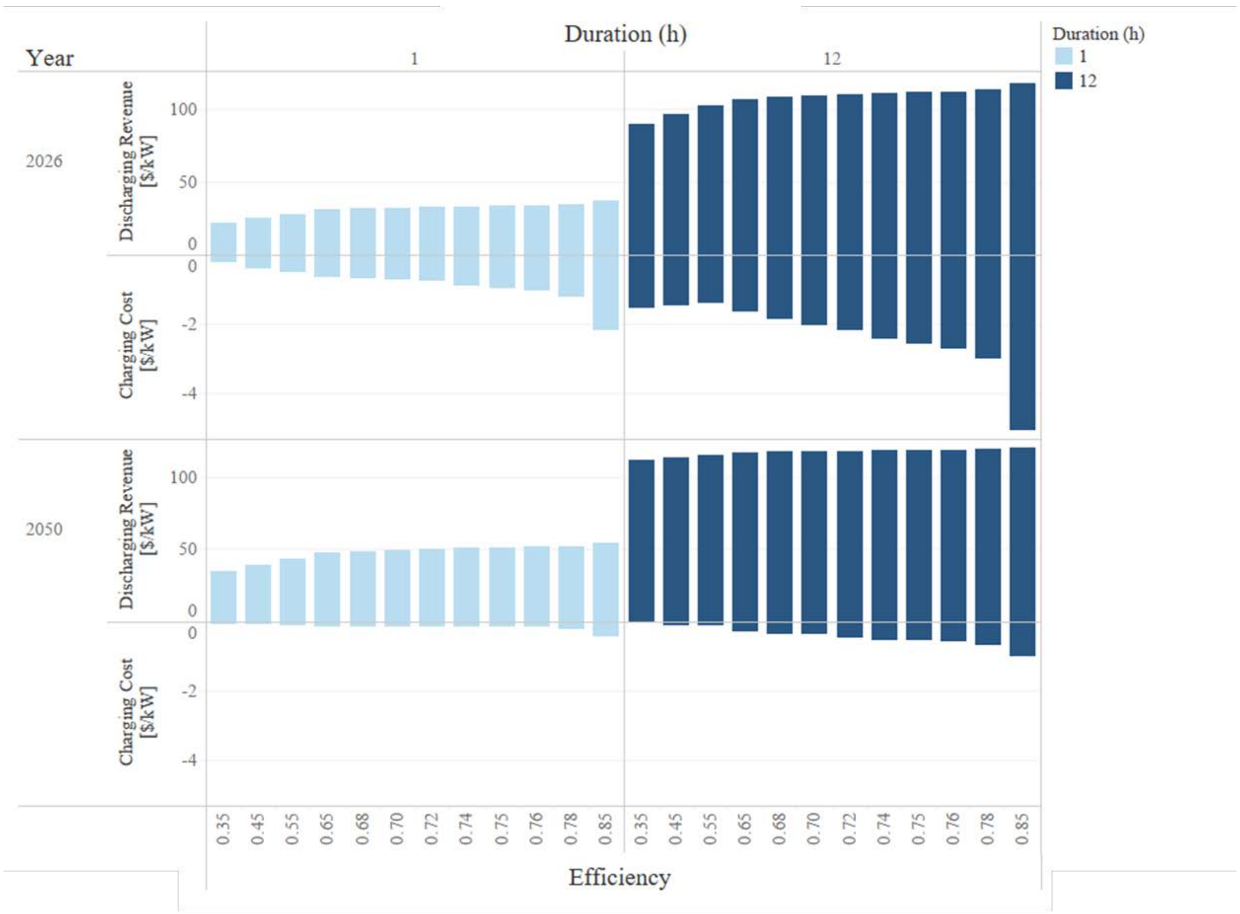

Figure 16. Distinguish of revenue into charging and discharging cost for 1 and 12-hr duration under a business-as-usual scenario using the Cambium data

4 Conclusion

This work has examined potential storage revenue using reported revenue data from FERC, historical energy-only electricity prices, and projected bulk electricity system prices. In conducting this work, we found the following:

- There is substantial variation in potential storage energy revenue in all three datasets we examined. For the historical datasets, this variation is driven by the electricity prices at specific nodes or in specific market regions, with some nodes showing much more variation in prices than other nodes. For the forward-looking datasets, the variation was driven by how the electricity generation mix changes.

- The variation in prices could dwarf design decisions for energy storage. In other words, being able to site a storage device at the “best” node can be more important than having the “best” storage device (though the device would still need to meet “good enough” standards). However, there is also the potential that siting storage at a high-value node might reduce the revenue potential by alleviating congestion or other constraints.

- The cost of the lowest-price nodes is considerably lower than the current cost of storage, indicating substantial cost reductions would be needed for storage to be cost-competitive at any location.

- Round-trip efficiency is an important but second-order driver of revenue, and the revenue-efficiency relationship is slightly nonlinear—meaning the value of better round-trip efficiency declines as efficiency increases.

Though this work has covered the contiguous United States, more work could be done to further explore the potential for storage revenue. That work includes capturing ancillary services revenue opportunities and examining market-specific capacity revenue opportunities.

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Appendix A. Impact of ancillary services in modeled revenue results

The modeling results in section 3.2 using historical pricing data used energy-only prices when calculating storage revenue outputs. However, because storage can also earn revenue from the ancillary service market, we present this brief revenue analysis for storage participation in both the energy-only market and the combined energy and ancillary services markets within CAISO. This analysis examines a 1 MW storage system with durations of 1, 2, and 4 hours. For this analysis, we collected energy and ancillary services market data from CAISO OASIS. The energy market dataset includes hourly day-ahead market prices for 1,845 nodes in 2022 and 2,334 nodes in 2023. Ancillary services data covers prices for four components—regulation up, regulation down, spinning reserve, and non-spinning reserve—in CAISO's two regions: northern (NP26) and southern (SP26), accounting for operations within each region. Using these datasets in the RODeO model, we calculate the maximum achievable revenue for each node.

Figure 17 illustrates the modeled revenue for storage participation across energy and ancillary market components, system durations, and CAISO ancillary market regions in 2022 and 2023. From this figure we can see that ancillary service revenues do not change much with duration. We can also observe that revenue from energy is the largest portion of the total revenue, especially as duration increases.

Figure 18 shows that total modeled revenue for storage which participates in both the energy and ancillary services market and for storage that participates only in the energy market in 2022 and 2023. In all cases, the total revenue in 2022 is greater than in 2023 while it increases with longer durations. The total revenue range for the nodes in NP26 is wider and greater than for the nodes in SP26. For example, the median of total revenue for energy and ancillary service market participants in NP26 is \$48.8/kW while it is \$27.9/kW for participants in SP26. Moreover, the revenue of 50% of the participant are between \$46.9/kW and \$53.7/kW while this range for SP26 is between \$37.5/kW and \$38.7/kW.

Figure 18 also illustrates the percentage of total revenue of storage systems participating in only in the energy market relative to those participating in both the energy and ancillary services markets. Higher percentage values signify smaller differences in total revenue between these participation types. In SP26, the percentage difference is generally above 75%, while in NP26, it ranges from 40% to 90%. This indicates that ancillary services market participation has a smaller impact on total revenue in SP26. Additionally, the percentage difference increases with longer-duration systems, as the effect of system duration on ancillary services market revenue is less significant than on energy market revenue.

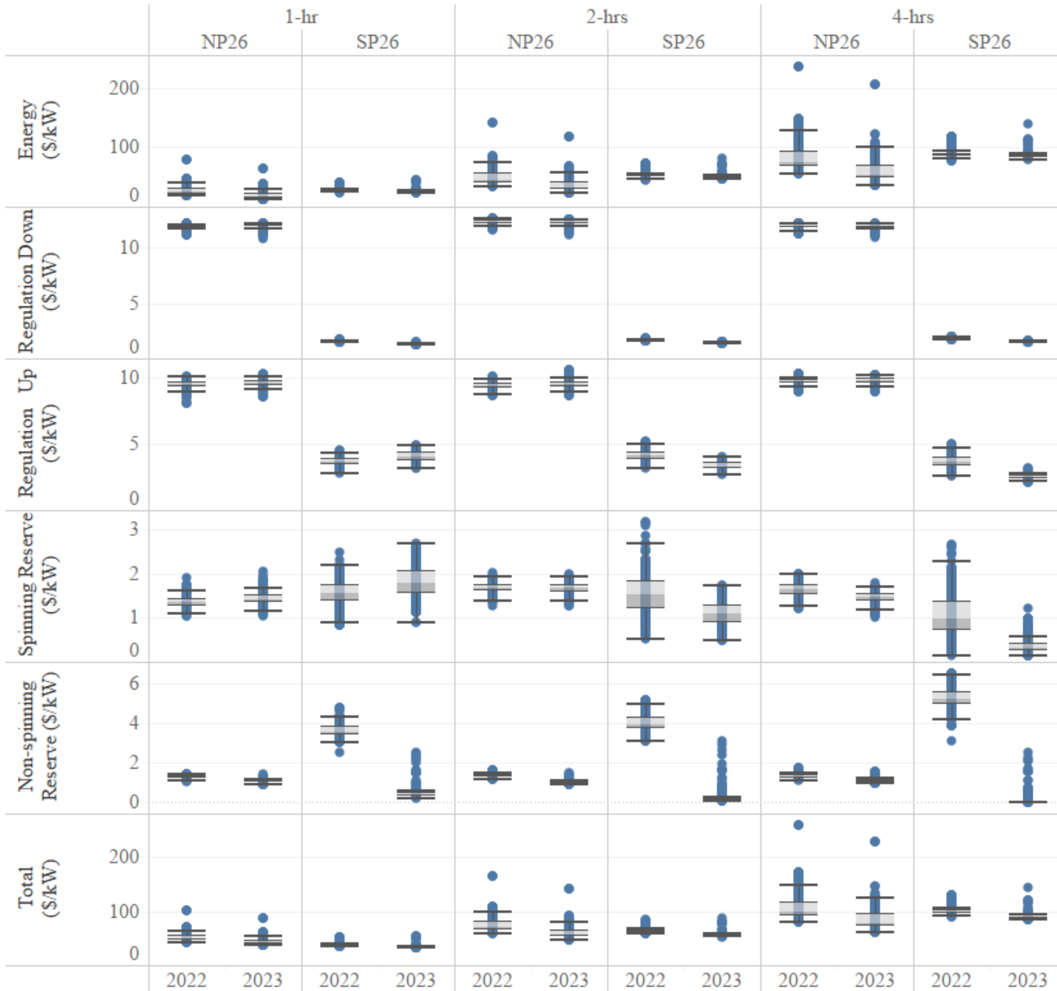

Figure 17: Modeled storage revenue using nodal pricing data from 2022 and 2023 for CAISO, categorized by market components for a 1 MW storage system with 1-hr, 2-hrs, and 4-hrs durations

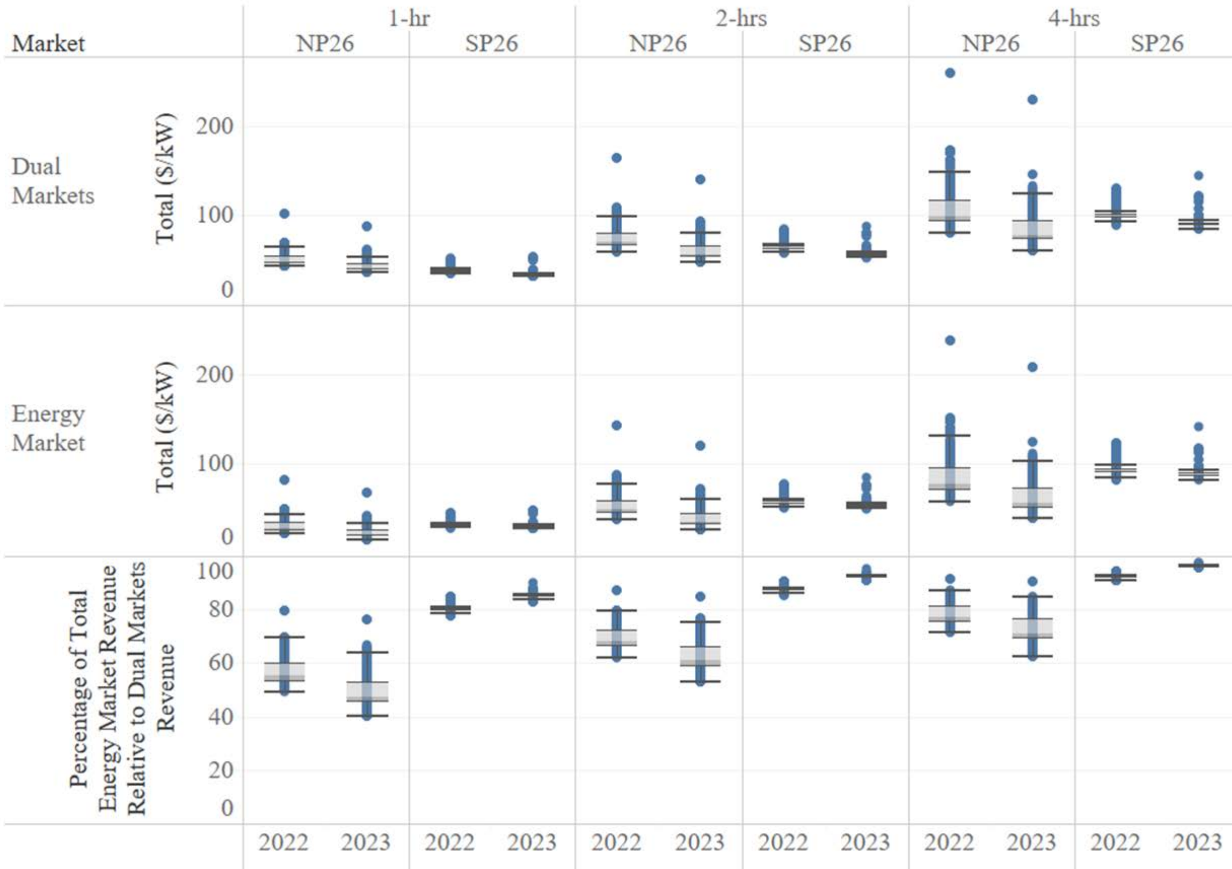

Figure 18: Total modeled storage revenue for storage systems participating in both the energy and ancillary services markets and the energy-only market, along with the percentage of total revenue of storage systems participating in only in the energy market relative to those participating in both the energy and ancillary services markets for 2022 and 2023.

Dual markets refer to combination of energy and ancillary services markets.

Appendix B. Detailed Revenue Figures

Figure 19 and Figure 20 present the modeled revenue using nodal pricing data from 2017 to 2021 for ERCOT, CAISO, and SPP and for a 1-MW system for durations from 1 MWh to 6 MWh and from 7 MWh to 12 MWh with 1MWh incrementation, respectively.

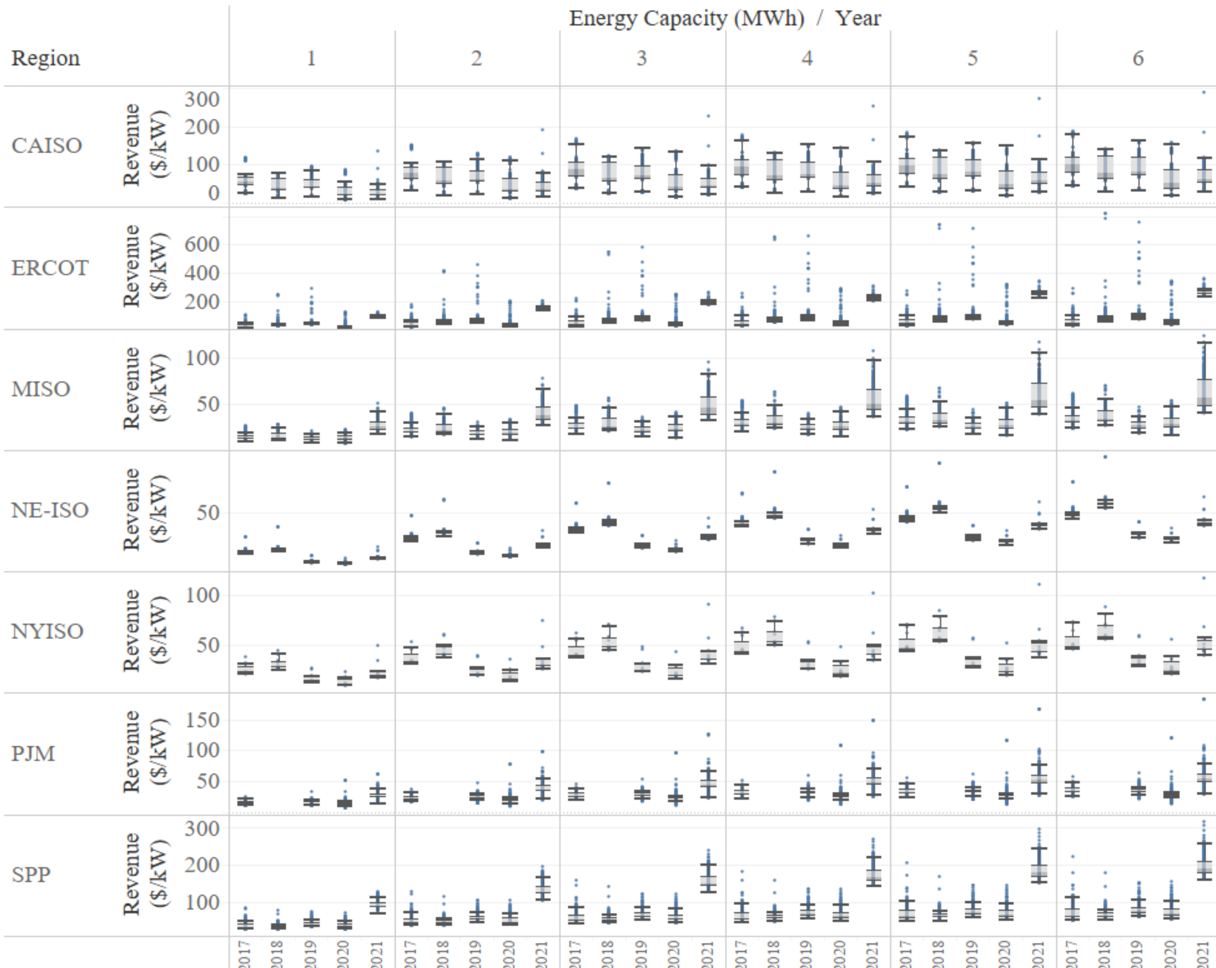

Figure 19. Modeled revenue using nodal pricing data from 2017 to 2021 for markets for a 1-MW system with duration from 1 MWh to 6 MWh

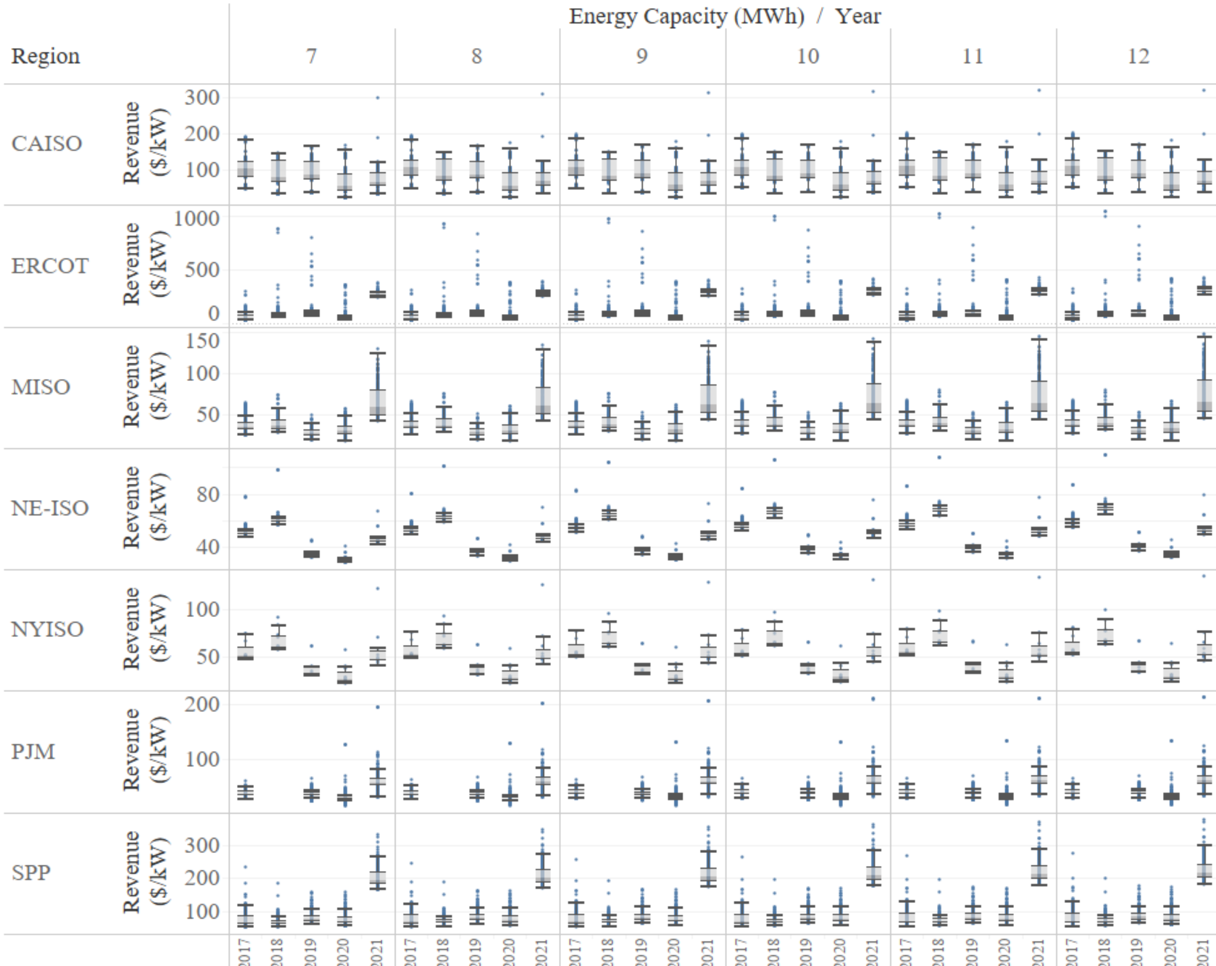

Figure 20 Modeled revenue using nodal pricing data from 2017 to 2021 for markets for a 1-MW system with duration from 7 MWh to 12 MWh