State of the Art Practices for Modeling Storage in Integrated Resource Planning

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Agenda

This training covers practices for incorporating utility-scale and distributed energy storage in integrated resource plans (IRPs), improving storage modeling, and reviewing IRP treatment of storage.

- Overview
  - Questions addressed in the training
  - Lab research that informs this training
  - IRP in the context of integrated grid planning
  - What are IRPs?
  - Barriers for storage in IRPs and improvements needed as storage grows
  - Guidance for reviewing storage modeling practices in IRPs
- Storage inputs and assumptions
  - Storage technology types
  - Model inputs and methodologies
  - Cost assumptions
- Resource planning models
  - Energy storage integration
  - Grid services
- Storage in IRP preferred portfolios
- Opportunities for improvement
- Questions states can ask
- Resources for more information

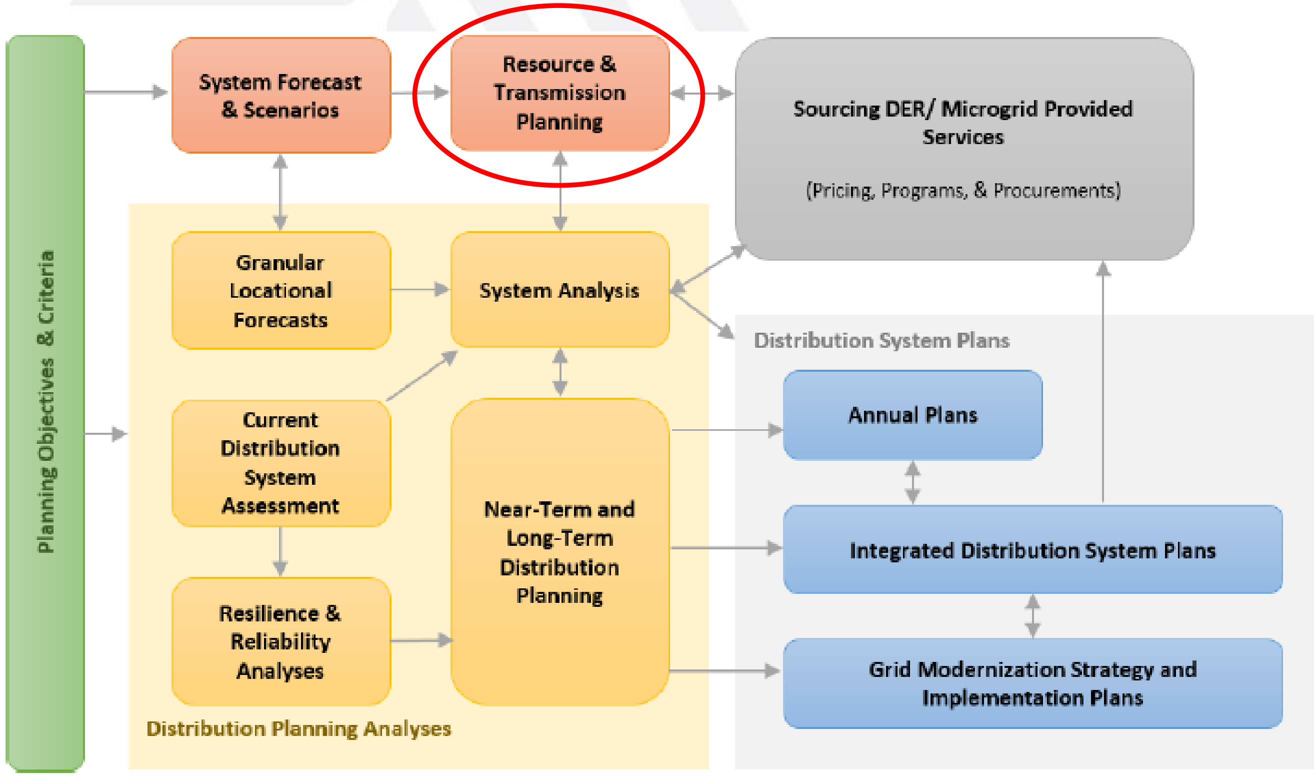
Questions addressed in the training

- What types of storage technologies do utilities consider in IRPs?
- What inputs and methodologies do utilities use for modeling utility-scale and distributed storage? How are approaches different for utility-scale and distributed storage?
- What information, assumptions, and methodologies do utilities use to forecast the cost of battery storage?
- How do utilities model storage as a potential resource and integrate it with other resources?
- What grid services do utilities consider in modeling storage, and how do they determine the value streams for each grid service?
- How much storage is included in utilities' preferred portfolios, and what are the primary drivers for including it?

Lab research that informs this training

- This training was informed by three research efforts by Berkeley Lab and Pacific Northwest National Laboratory (PNNL) that address energy storage practices in IRPs:
  - A 2019 PNNL study that examined how 21 U.S. utilities are treating energy storage in IRPs
  - A forthcoming PNNL study that builds on that work by identifying practices that utilities are developing to more accurately evaluate the costs and benefits of energy storage in the IRP process
  - Berkeley Lab research in response to a request from a state regulatory commission to identify best practices that utilities use to model utility-scale and distributed-scale energy storage in IRPs
    - See list of IRPs Extra Slides

IRP in the context of integrated grid planning



Source: DOE, [Modern Distribution Grid, Vol. 4](): Strategy and Implementation Planning Guidebook (final draft), 2020

What are IRPs?

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- IRP is a tool that utilities use to identify future energy and capacity needs and select the optimal resource portfolio for meeting them.
  - In the case of regulated utilities, prepared for state utility regulator – Regulatory action varies by state. Regulators may approve or acknowledge the IRP, or simply accept IRPs that meet filing requirements.
  - Used in vertically integrated states
  - Some states in market regions have re-introduced IRP (e.g., California, Michigan).

- IRPs provide insight into how utilities are adapting to changing technologies and policies.

Key IRP assumptions create barriers for storage

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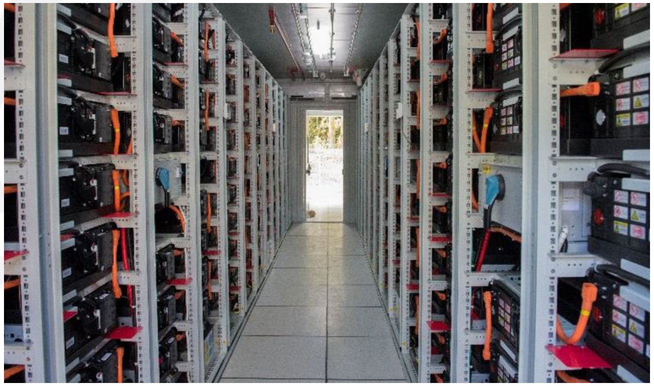
- Preparing an IRP is a complex exercise.
  - Load and generation must be kept in constant balance.
  - There are dozens of generators, market interfaces, fuel costs, and changing load patterns (e.g., related to distributed generation, electric vehicles).
  - For each interval, solving the load/generation equation requires consideration of many complex variables.
  - A 15-year plan looking at hourly intervals must solve for 131,400 data points.
- As a result, resource plans make several simplifying planning assumptions.
  - Hourly planning resolution
  - Substitution of reserve margins for ancillary services
- These assumptions cause the flexibility and scalability benefits of energy storage to be undervalued.
  - Hourly planning resolution: Flexible, intra-hour benefits omitted
  - Reserve margins: Ancillary service benefits omitted
  - Generation focus: Transmission often not included; distribution benefits typically omitted

IRP improvements needed as storage grows

- There is no standard approach for modeling storage in IRPs, and storage is not fully integrated into models utilities currently use.
- More accurate inputs (e.g., up to date costs and forecasts) and improved modeling methods (e.g., assessing benefits for a wider range of grid services, incorporating behind-the-meter (BTM) applications) are needed to better integrate storage into planning processes.
- As more storage technologies reach commercial maturity, more storage types can be modeled. Accurate technical parameters for various types of storage are needed (e.g., ramp rate, battery degradation, thermal limitations, end-of-life costs).
- Innovative modeling methods provide opportunities to capture additional operational benefits that can be incorporated in IRP analyses.

SCE's 20 MW, 4-hour storage plant in Mira Loma, CA



PSE's 2 MW, 4-hour storage pilot in Glacier, WA

Guidance for reviewing storage modeling practices in IRPs (1)

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- Look for storage assumptions, rationales, and references included within each component of the IRP.
  - **Near term action plan**: may include pilots, customer programs, or procurement solicitations in development
  - **Resource development plan**: outcomes of modeled scenarios, often with a portfolio identified, including capacity, technology type, and procurement year of resources
  - **Resource characteristics**: assumptions used for costs, technical parameters, and resources available for selection
  - **Load forecast/demand-side modeling**: assumptions for adoption of distributed storage, its impact on demand-side modeling, and how storage is integrated into bulk system analysis
  - **Future conditions**: may include sensitivities for technology maturity and environmental regulations that could influence storage costs and value
  - **Portfolio modeling**: a description of capacity expansion and production cost models used, how they interact within the analysis framework, sensitivities and assumptions for each scenario, resources selected for each portfolio, and a comparison of outcomes

Guidance for reviewing storage modeling practices in IRPs (2)

- The same principles should apply to all assumptions or methodologies for modeling storage.
  - Based on the best information or methods available
  - Supported by traceable references to external sources
  - Acknowledges uncertainty and identifies possible alternatives
  - Consistent with treatment of other potential resources
  - Considers non-conventional behavior of storage resource
- Determine if potential stages of storage modeling are present and performed either within the IRP or calculated externally and supported by references.
  - Technology maturity forecast (i.e., cost and technical parameters)
  - Behind-the-meter storage adoption
  - Distribution system analysis of potential storage capacity and locational value
  - Loss-of-load-expectation studies
  - Capacity expansion modeling
  - Production cost modeling
  - Side calculations of additional value streams (e.g., flexibility, sub-hourly modeling)

Storage inputs and assumptions

Overview of existing storage technology types

- Energy storage technologies can be categorized into four broad categories: electrochemical, mechanical, thermal, and chemical.

- Technologies generally need to reach a level of maturity where cost and technical parameters are well-established to be included in IRPs.
  - For example, Michigan specifies technologies that are "commercially available."

- Technologies included in reviewed IRPs are highlighted in red in the table.

Category	Energy storage technologies (some in R&D)
Electrochemical	• Li-ion • Na-ion and Na metal • Lead Acid • Zinc • Other metals (Mg, Al) • Redox Flow • Capacitors
Mechanical	• Pumped hydro • Compressed air • Flywheels • Geomechanical • Gravitational
Thermal	• High-temperature sensible heat • Low-temperature storage • Phase change materials • Thermo-photovoltaic • Thermochemical
Chemical	• Hydrogen • Ammonia • Other chemical carriers

Source: DOE, Energy Storage Grand Challenge: Policy and Valuation Track Lab Working Group Kickoff, 2020

Storage technology types included in IRPs

- All IRPs reviewed estimated the potential of utility-scale Li-ion batteries; some included additional technologies.
- Utilities modeled standalone and hybrid systems separately.
- Utilities did not specify distributed energy storage types, but the majority of commercially-available small-scale storage is lithium-ion.
- Utilities excluded some storage technologies as less mature or posing higher risks of cost and operational uncertainty.

	Hoosier	IPL	Vectren	APS	DEC	PSE	SMUD	Xcel	PGE	El Paso	GMP	SCE
Utility-scale energy storage												
Electrochemical												
Li-ion battery	x	x	x	x	x	x	x	x	X	X	X	X
Flow battery			x	x	x	x						
Mechanical												
Compressed air storage				x								
Pumped storage				x		x			X			X
Hybrid (storage co-located with solar, wind, or gas)												
Solar + Li-ion battery	x		x	x	x	x		x	X	X	X	
Wind + Li-ion battery			x			x		x		X		
Distributed energy storage												
Battery*				x	x	x	x	x	X		X	

*Utilities did not specify DER battery chemistry.

Source: Cesca Miller, Berkeley Lab

Inputs and methodologies for utility-scale storage

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- IRPs include a range of procurement levels for utility-scale energy storage in scenarios tested, based on different priorities and assumptions, such as:
  - Renewable energy procurement goals, carbon policies, economic conditions, and power plant retirements
- Utilities use results of resource optimization modeling, as well as simply adding storage to portfolios, to test storage in a variety of scenarios.
- Storage units are included as modular blocks to mirror traditional resources.
  - For example, El Paso Electric added storage in incremental 15 MW or 50 MW amounts.
- All utilities modeled 4-hour systems, and some modeled 2-, 6-, and 8-hour durations as well.

Utility	Standalone Storage Range	Hybrid System Range	Number of Scenarios
Hoosier	0-250 MW	Not included	6
IPL	380-1,040 MW	Not included	5
Vectren	0-152 MW	0-126 MW (solar), 0-340 MW (wind)	5
APS	852-10,140 MW	Not included	4
DEC	1,050 MW-7,400 MW (includes standalone and hybrid)		6
PSE	Modeled in 25 MW blocks, range not provided	Not included	3
SMUD	246-661 MW	Not included	3
Xcel	0-400 MW	0-600 MW (solar), 0-900 MW (wind)	16
PGE	0-299 MW	0-150 MW (solar)	43
El Paso	0-130 MW	0-60 MW (solar), 0-15 MW (wind)	8
GMP	0-100 MW	Not specified	Not specified
SCE	2,861 MW-6,503 MW	Not included	3

Source: Cesca Miller, Berkeley Lab

Inputs and methodologies for distributed storage

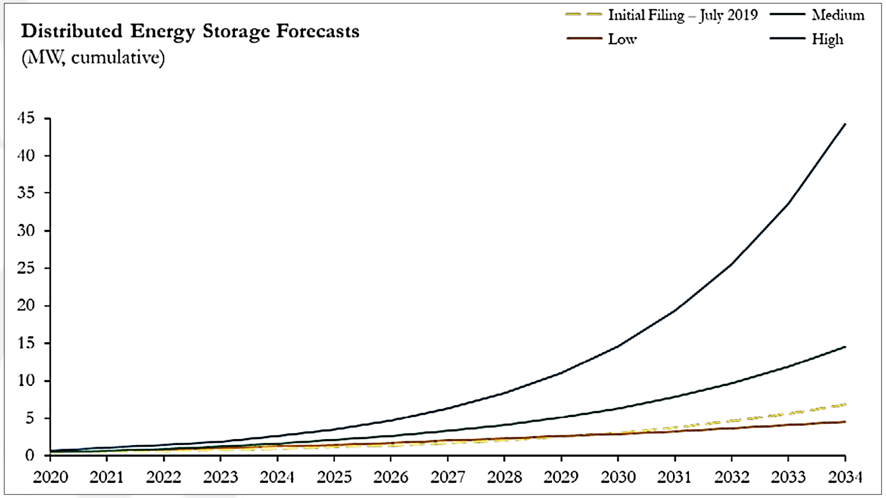
- Some IRPs incorporate distributed storage in load forecasts and planning models, but it is not a common approach.
- Storage can be included in load forecasts as a demand-side management (DSM) resource or a customer-controlled resource (i.e., not dispatchable by the utility).
- In capacity expansion or production cost models, distributed storage can be included as a selectable resource.
  - PSE included distributed storage as a utility-owned resource; PGE included it as a customer-owned resource.
- While distributed storage can provide demand reduction and other grid services, exclusion from load forecasts and resource modeling limits its understood value and justification for incentivizing customer adoption.

Utility	Distributed Storage Included	Load Forecast Adjustment?	Ownership	Quantity
Hoosier	None	No	None specified	None
IPL	None	No	None specified	None
Vectren	None	No	None specified	None
APS	Distributed storage included as part of DSM programs	No	Customer	Unknown
DEC	Load shifting from Bring-Your-Own Battery program	Not specified	Customer	400 kW
PSE	Utility-owned distributed storage included in resource optimization as a non-wires alternative to meet some distribution system needs	No	Utility	25 MW blocks
SMUD	Load forecast includes distributed storage through customer adoption and utility procurement (80% battery, 20% thermal energy storage)	Yes	Utility procurement of customer storage	At least 9 MW
Xcel	Customer-sited storage	Yes	Customer	Variable
PGE	Distributed storage separated into non-dispatchable and dispatchable segments	Yes	Customer	Variable
El Paso	None	No	None specified	None
GMP	Bring your own device and Tesla Powerwall 2.0 Battery Pilot programs	Not specified	Customer	Potentially up to 47 MW
SCE	Distributed storage included as part of statewide baseline load forecast	Yes	None specified	1,800 MW added statewide by 2030

Source: Cesca Miller, Berkeley Lab

Case study: Xcel Energy customer adoption forecast

- Xcel created low, mid, and high forecasts for distributed storage customer adoption, based on current adoption levels and interconnection applications combined with third-party data.
- The utility applied different methods for each growth level:
  - For its **high** scenario, Xcel applied rates for completed energy storage units for Northern States Power Minnesota in 2017 and 2018 to growth rates forecasted by Wood Mackenzie.
  - For its **medium** scenario, Xcel applied rates for completed energy storage units to a lower growth rate from Navigant Research.
  - For its **low** scenario, Xcel extrapolated the historical average growth rate of interconnection applications from 2017 and 2018 by applying additional growth rates.



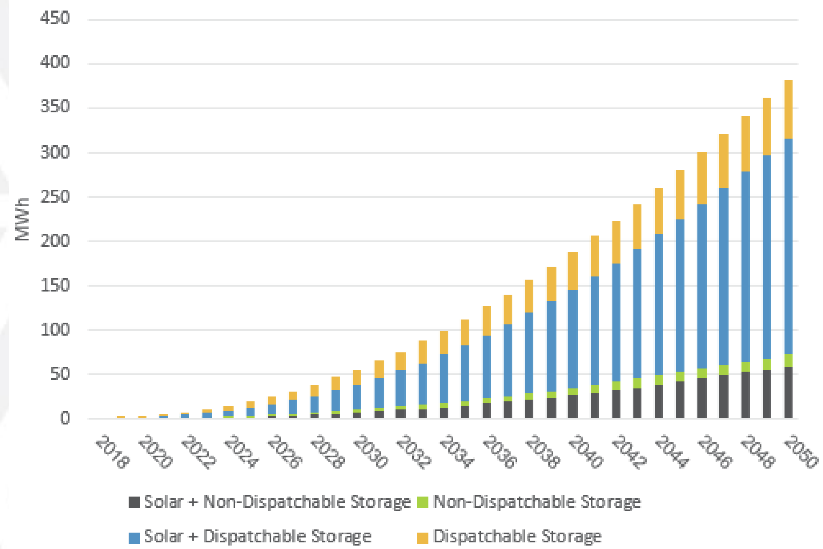
	Cumulative MW		
	Low	Medium	High
2025	1	2	3
2030	2	5	12
2034	3	12	45

Source: Xcel, Upper Midwest Integrated Resource Plan 2020-2034, Supplement, 2020

Case study: PGE's customer-sited dispatchable storage

- PGE included customer-sited distributed storage through separate non-dispatchable and dispatchable forecasts.
  - Both forecasts are incorporated into PGE's load adjustment forecasts.
  - PGE assumed dispatchable storage could not be used for customer bill management.
  - Customer incentive levels determined distribution between non-dispatchable and dispatchable storage.
- The utility included capacity from dispatchable storage forecasts in capacity expansion modeling.

Distributed storage forecast by system type



Cumulative customer resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Energy Efficiency (MWa)*	108	133	157	111	140	167	108	133	157
Demand Response†									
Summer DR (MW)	190	202	211	329	359	383	104	106	108
Winter DR (MW)	129	136	141	263	282	297	72	73	73
Dispatchable Standby Generation (MW)	136	137	137	136	137	137	136	137	137
Dispatchable Customer Storage (MW)	2.2	3.0	4.0	7.3	9.1	11.2	1.1	1.6	2.2

Source: PGE, Integrated Resource Plan, 2019

Data sources for cost assumptions

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- Utilities employed a combination of public, third-party, and internal price data to develop cost curve assumptions for energy storage.

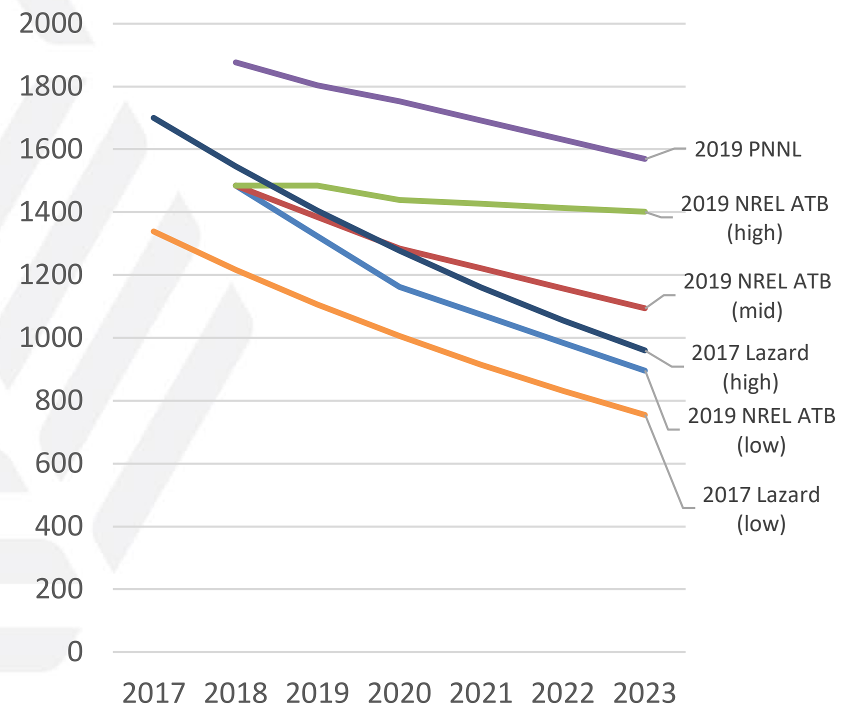
Data sources for energy storage costs by utility

	NREL	Lazard	EIA	PNNL	IHS	Wood Mackenzie	Bloomberg	Internal Data*
Hoosier			X					X
IPL	X	X			X	X	X	X
Vectren	X							X
APS						X		X
DEC	X	X		X				X
PSE	X							X
SMUD	X	X						X
Xcel	X							X
PGE			X				X	X
El Paso	X	X						
GMP	X							
SCE	X	X						

*Includes data from resource solicitations, known interconnection costs, previous consulting work, and other undisclosed information.

Source: Cesca Miller, Berkeley Lab

Capital cost of 4-hour lithium-ion utility-scale storage ($/kW)



Source: Compiled by Berkeley Lab

Cost assumptions for utility-scale storage (1)

- IRPs reported capital costs based on technology type and year of installation.
- Some IRPs applied cost sensitivities based on scenarios modeled.
  - The reference case represents the mid-range.
- Comparison of capital costs between IRPs is difficult due to lack of transparency in assumptions and reporting.
  - Some IRPs reported capital costs while others reported levelized costs.
  - IRPs reviewed do not report interconnection and engineering costs (except for PSE).

Reference case capital costs and scenarios for utility-scale Li-ion batteries

Utility*	Reference Case Capital Cost (2020 $/kW, 4-hour)	Cost Curve Scenarios
IPL	1,378†	Five curves designed to reach +/- 25% and +/-50% of reference case costs in 2038.
Vectren	1,498	Three curves designed as base, lower, and higher. Base cost in 2030 is 70% of 2020 cost; in 2039 it is approximately 56% of 2020 cost.
APS	1,059†	Did not provide details.
DEC	3,188†	Capital cost declines by 49% in 2030. Did not provide details for cost curve scenarios.
PSE	2,100	"Mid Technology Cost" scenario from NREL cost data, where capital cost declines by 50% by 2050.
SMUD	1,899†	Single cost curve where levelized cost declines by 30% by 2030.
Xcel	3,436†	Three cost curves designed as base, lower, and higher. Base cost in 2030 is 78% of 2020 cost; in 2040 it is 83% of 2020 cost (the cost curve increases after 2030).
PGE	1,764	Three cost curves designed as reference, low, and high. Reference cost decreases linearly, reaching 55% of 2020 cost in 2050.
El Paso	1,775†	None provided
GMP	Not provided	None provided
SCE	1,251†	Capital cost declines by 45% in 2030 based on mid-level costs from CPUC's 2019 Inputs and Assumptions

*Hoosier redacted cost estimates and cost curve scenarios

†Estimated reference cost capital cost

Source: Cesca Miller, Berkeley Lab

Cost assumptions for utility-scale storage (2)

- Some IRPs also reported operation and maintenance costs based on technology type and duration.
- There is little description of assumptions and how costs are divided into fixed and variable components.
- While lithium-ion batteries have fewer moving parts than other resources, O&M needs to account for other potentially costly elements, such as augmentation (i.e., module replacement).
- NREL assumed a fixed O&M cost of $34/kW-yr and a variable O&M cost of $0/MWh in 2020 for a 4-hour Li-ion system, which is higher than most of the IRP assumptions.
- Comparing technologies, Vectren reported a fixed O&M cost of $110.10/kW-yr for flow batteries while APS reported $31.40/kW-yr.

Reference fixed and variable O&M costs for utility-scale Li-ion batteries

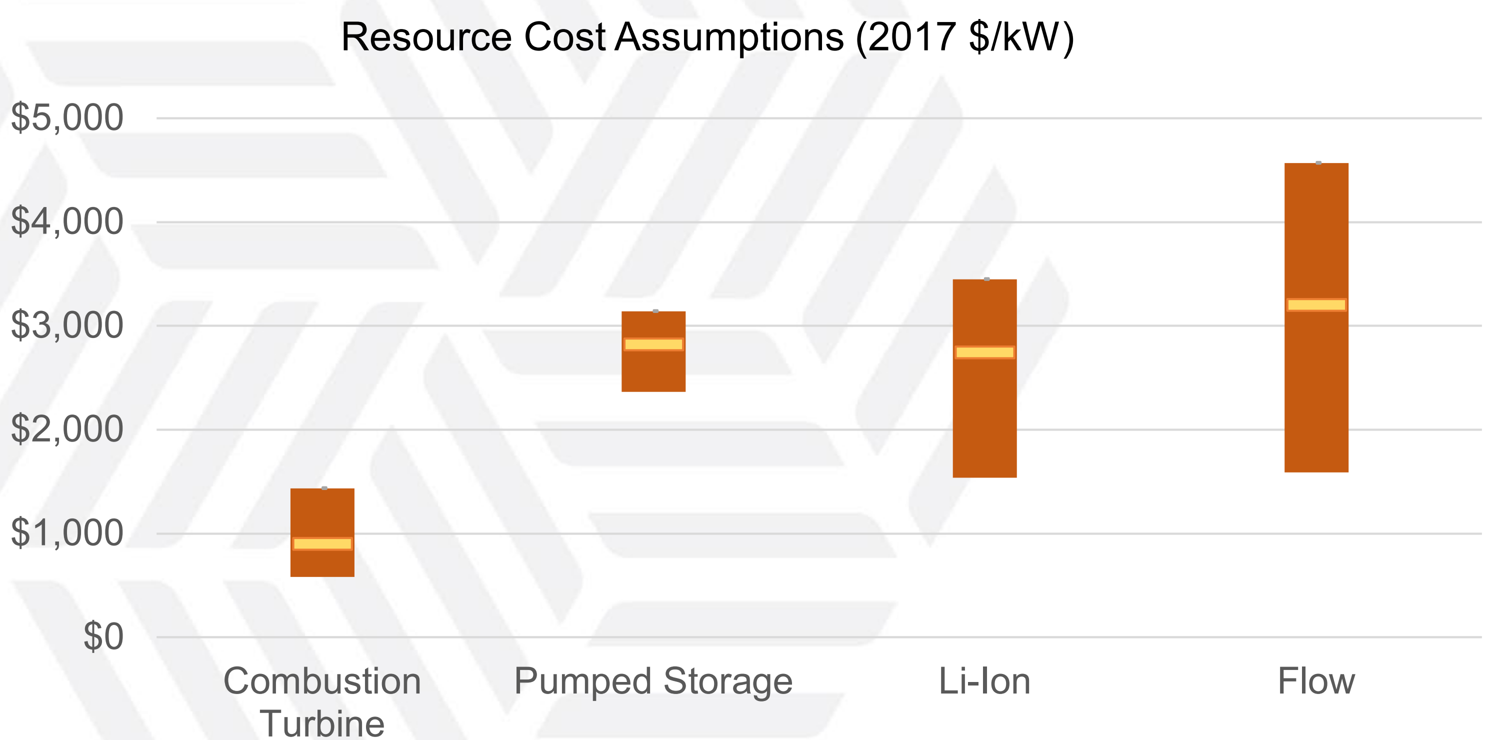
Utility*	Fixed O&M (2020 $/kW-yr, Li-ion 4-hour)	Variable O&M (2020 $/MWh, Li-ion 4-hour)
IPL	19.02	4.53
Vectren	18.85	6.07
APS	24.50	0.00
DEC	Not provided	Not provided
PSE	31.93	0.00
SMUD	Not provided*	Not provided
Xcel	Not provided*	Not provided
PGE	31.10	0.00
El Paso	9.76	30.00
GMP	Not provided	Not provided
SCE	2.87	0.00

*O&M costs were integrated directly into levelized costs

Source: Cesca Miller, Berkeley Lab

Utilities relatively uncertain about battery costs

- Cost assumptions for technologically mature resources such as combustion turbines and pumped storage tend to cover a smaller range than assumptions for less mature resources, such as lithium-ion and flow batteries.



Source: Cooke, A.L., Twitchell, J.B., O'Neil, R.S. 2019. *Energy Storage in Integrated Resource Plans*. PNNL.

Case study—Northern Indiana Public Service Co.: More accurate cost assumptions

- For its 2018 IRP, NIPSCO conducted an all-source request for proposals at the beginning of the process.
  - NIPSCO received 90 bids representing nine resource types (including nine standalone storage bids and 12 hybrid bids). The utility used the results to inform IRP cost assumptions.

Results of NIPSCO's Initial Cost Survey

2017 $/kW	Solar PV – Utility Scale	Solar PV – DG	Onshore Wind	Offshore wind	Li-Ion battery (4-hr)	Biomass	CHP	Microturbines
Average	1,673	2,466	1,719	5,728	2,110	5,475	3,182	5,001
Median	1,453	2,466	1,677	6,454	2,160	6,522	2,213	5,001
Min	1,155	2,400	1,425	3,430	1,317	2,500	1,350	4,943
Max	2,370	2,532	1,977	7,300	3,114	7,300	5,984	5,059

Source: NIPSCO, 2018 Integrated Resource Plan, 2018

- Average bid prices received in response to the RFP:
  - Solar + storage: $1,183/kW
  - Standalone storage: $1,349/kW

Resource planning models

Resource planning models used in IRPs

- Several industry-standard capacity expansion and production cost models are available.
  - Capacity expansion models determine optimal resource selections over the planning horizon under various assumptions and scenarios.
  - Production cost models typically operate at hourly intervals, but can operate at sub-hourly internals with additional data, time, and cost.
- Utilities typically use both types of modeling (often within the same tool) to address different aspects of planning.
- Modeling battery dispatch using sub-hourly intervals can potentially capture additional storage benefits, such as ancillary services (e.g., fast ramping, voltage control, or frequency response).

Utility	Production Cost Model	Sub-hourly Modeling	Capacity Expansion Model(s)
Hoosier	Aurora	No	Aurora
IPL	PowerSimm	No	PowerSimm
Vectren	Aurora	No	Aurora
APS	Aurora	Yes	Strategist
DEC	PROSYM and SERVM	No	ABB’s System Optimizer
PSE	Aurora	Yes	Aurora
SMUD	PLEXOS	No	RESOLVE
Xcel	None	No	EnCompass and Strategist
PGE	Aurora and ROM	Yes	Aurora and ROSE-E
El Paso	None	No	Strategist
GMP	Unknown	Unknown	Unknown
SCE	PLEXOS	Unknown	RESOLVE (minimally) and ABB CE

Source: Cesca Miller, Berkeley Lab

Integrating storage into models

- Storage behaves differently than traditional resources:*
  - Bi-directional charge and discharge capabilities
  - Sub-hourly discharge without ramping
  - Variable available capacity (i.e., state of charge)
  - Energy limited
- Utilities can integrate additional modules or tools into IRP modeling processes to more accurately capture storage behavior.
- Aurora and PowerSimm sub-modules are designed to model storage.
  - These add capability to dispatch storage simultaneously with other resources using accurate technical parameters (e.g., roundtrip efficiency, floating state of charge).
- Utilities modeled benefits in production cost models where capacity expansion models did not capture full benefits.
  - Xcel relied on EnCompass for modeling storage dispatch since Strategist did not dispatch storage simultaneously with other resources.
  - Duke's capacity expansion model could not account for roundtrip efficiency losses.
- PSE and PGE used external modules to calculate flexibility benefits of storage, since sub-hourly calculations were too taxing for the production capacity expansion model.
  - The utilities used PLEXOS and ROM, respectively.

*Further, standalone and hybrid storage behave differently and have different benefits (Gorman et al. 2021).

Potential grid services that storage could provide

- Storage primarily provides resource adequacy, but low operational costs make it valuable for providing additional grid services.
- Storage value for utilities can be broadly grouped into four categories of grid services (see table).
- Using storage for multiple grid services increases benefits, although using storage for some services reduces its ability to provide others.
- In restructured regions, potential grid services depend in part on storage participation rules for centrally-organized wholesale electricity markets.

Potential battery value to utilities

Energy price (cost) arbitrage	Traditional energy price arbitrage
	Day-ahead and real-time price (cost) arbitrage
	Congestion management
	Renewable energy integration
Ancillary services	Frequency regulation
	Operating reserves
Capacity	System resource adequacy
	Local resource adequacy
	Distribution
	Transmission
Reliability and resilience	Backup generation

Source: F. Kahrl, Berkeley Lab, 2021

Grid services utilities modeled for storage

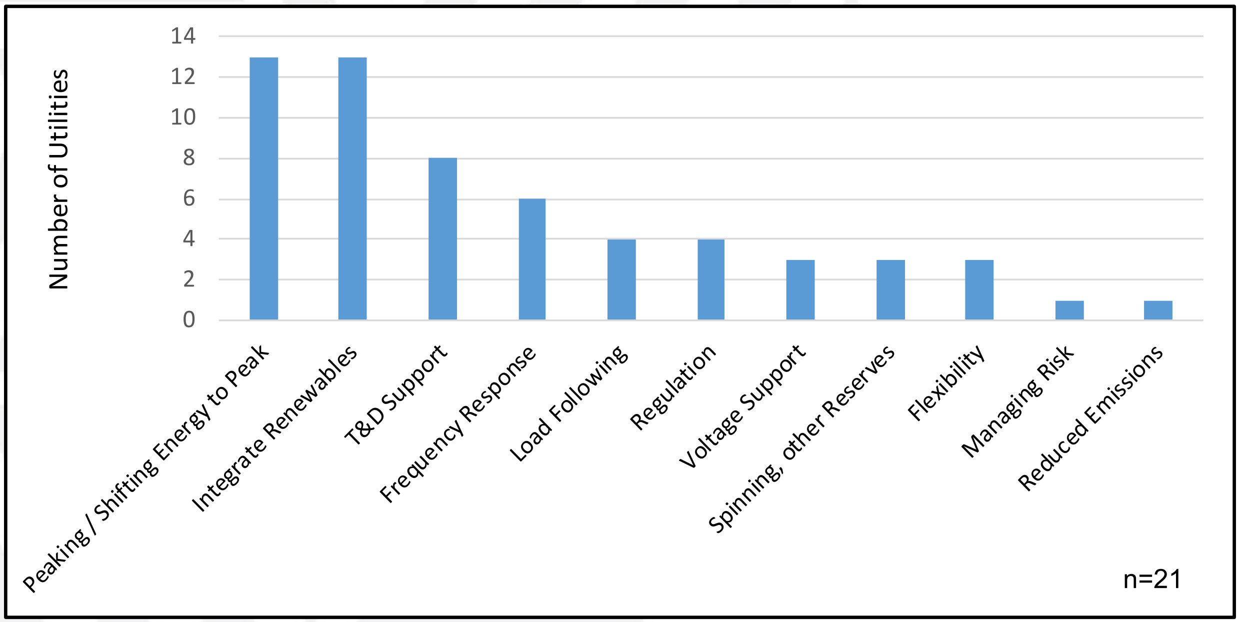
- IRPs reviewed rarely stated what grid services were included in calculating storage benefits, besides resource adequacy.
- IRPs discussed potential grid services that storage could provide, but did not clarify if they calculated these benefits. For example:
  - Xcel Energy discussed black start and frequency response applications.
  - IPL highlighted the use of its existing storage system for primary frequency response and "other reliability services."
- Both IRPs considering flexibility enabled by storage (PSE and PGE) calculated these benefits in a separate model.

	Generation: Energy	Generation: Capacity	Ancillary Services	Flexibility	Co-location With Renewables
Hoosier		X			X
IPL	X	X	X		
Vectren		X			X
APS		X			
DEC		X			
PSE		X		X	
SMUD		X			
Xcel		X			
PGE	X	X	X	X	X
El Paso		X			
GMP		X			
SCE		X			

Source: Cesca Miller, Berkeley Lab

Storage services identified in PNNL's review of IRPs

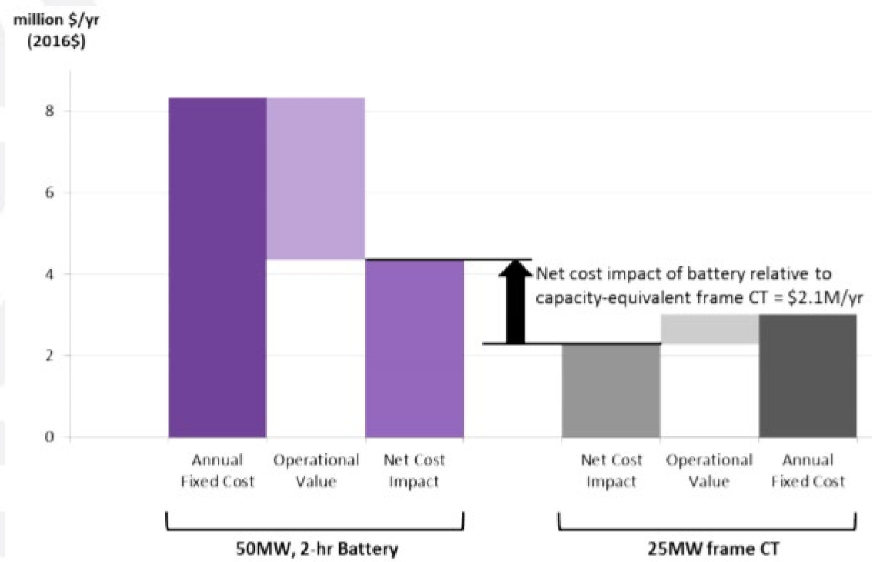
- Some IRPs identify multiple services that storage can provide, but may not analyze or capture these benefits.
- Several utilities identified a lack of modeling tools capable of analyzing storage, but some utilities are beginning to procure new tools and develop new processes for improving how they model storage.
- In general IRPs are much better at capturing the costs of energy storage technologies than their benefits.



Source: Cooke, A.L., Twitchell, J.B., O'Neil, R.S. 2019. *Energy Storage in Integrated Resource Plans*. PNNL.

Case study: Portland General Electric's Net Cost Model (2016)

- Recognizing that its hourly capacity expansion model would not capture the intra-hour benefits of energy storage and other flexible resources, PGE developed the "Net Cost" methodology for its 2016 IRP.
  - PGE-developed, external model to quantify intra-hour benefits of a resource ("operational value")
  - Operational value credited against resource's annual fixed cost
- While storage was not the most cost-effective option under this analysis, the methodology reduced the delta between storage and other resources.



Source: PGE, Integrated resource Plan, 2016, p. 239

Case study: Portland General Electric's valuation of flexibility & long-duration storage (2019)

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- For its 2019 IRP, PGE made three changes that impacted its valuation of energy storage:
  - Constrained the model from selecting new GHG-emitting resources
  - Fully integrated the utility's in-house, intra-hour Resource Optimization Model (ROM) into the capacity expansion process
  - Allowed the capacity expansion model to select dispatchable, behind-the-meter storage to meet capacity needs
- Using ROM, PGE modeled its system one week at a time, stepping through three levels of granularity while preserving commitments made in previous levels (e.g., day-ahead, hour-ahead, and real-time).
- Through this process, PGE was able to drill down into its real-time ancillary service needs and quantify a flexibility value (levelized value of real-time ancillary service benefits) for different resources.

	Flexibility Value (2020$/kW-yr)
Solar + Storage	-
2-hour Battery	$23.73
4-hour Battery	$28.10
6-hour Battery	$29.43
Pumped Storage	$25.95
CCCT	$8.40
LMS 100	$8.87
Reciprocating Engines	$9.19
SCCT	$4.82

Source: PGE, Integrated Resource Plan, 2019

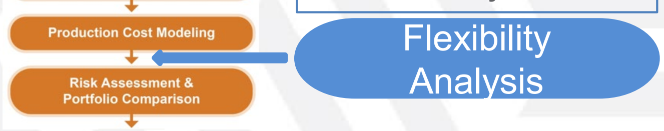
Case study: PSE calculation of flexibility savings (1)

- In its 2017 and 2021 IRPs, Puget Sound Energy developed two ways to use an external model to calculate flexibility benefits and incorporate those benefits into the IRP.

2017: Portfolio Re-Optimization

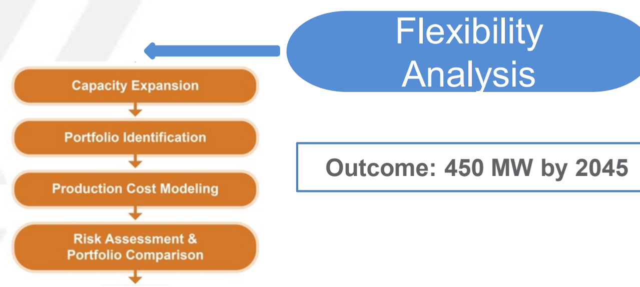
- Re-runs each portfolio through a sub-hourly model (PLEXOS) nine times, adding a different flexible resource each time
- Any reductions in portfolio costs are levelized and attributed to the resource
- The portfolio is then re-run through the capacity expansion model with the new values

Outcome: 75 MW by 2037 became 50 MW by 2023 & 75 MW by 2027



2021: Informed Portfolio Development

- Prior to modeling each scenario, PSE performs the flexibility analysis using its existing portfolio
- Flexibility benefits identified through this process are used in the resource cost assumptions in each portfolio's development



Outcome: 450 MW by 2045

Source: Jeremy Twitchell, PNNL

Case study: PSE calculation of flexibility savings (2)

- PSE simulated flexibility needs and resources in 2021 by dispatching resources using 5-minute load and generation intervals with hourly market participation intervals.
  - Resources were individually added to the current portfolio to measure their isolated impact on cost savings.
  - Lithium-ion batteries have slightly higher cost savings than flow batteries, and cost savings are significantly improved with increased duration.
  - Only pumped hydro has higher value than reciprocating peaker plants.
  - The difference in savings for different storage technologies with identical durations is unclear.

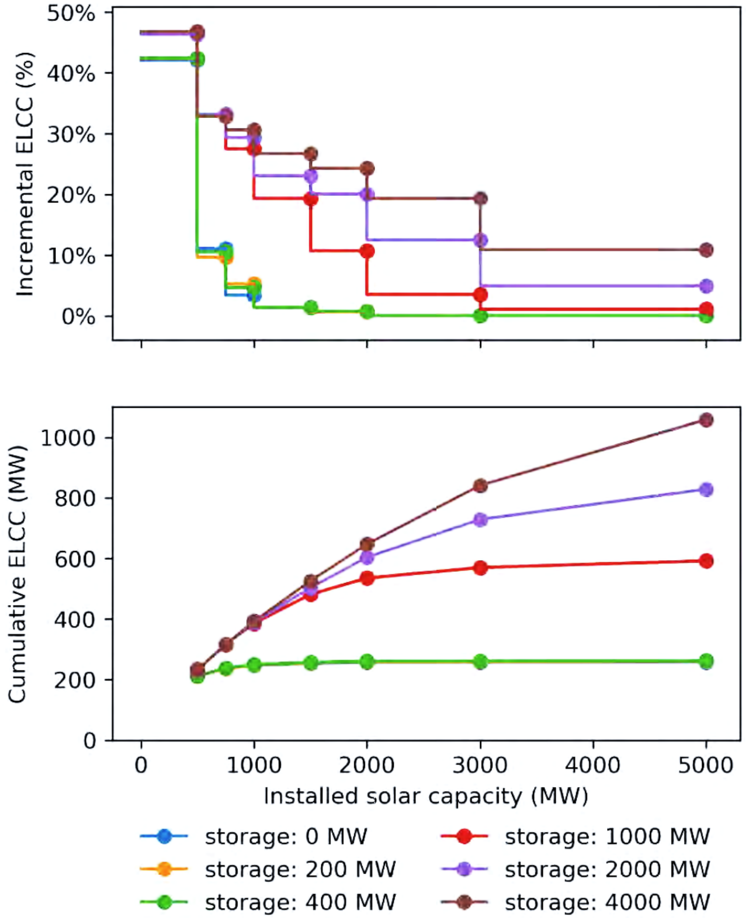
PSE sub-hourly system flexibility cost savings

Resource	Flexibility Cost Savings ($/kw-yr)
CCCT	0.03
Frame Peaker	1.15
Recip Peaker	8.16
Lithium-ion battery 2hr	3.11
Lithium-ion battery 4hr	7.89
Flow battery 4hr	1.53
Flow battery 6hr	7.44
Pumped Storage Hydro 10hr	10.24

Source: PSE, Integrated Resource Plan, 2021

Effective load carrying capacity calculations (1)

- Effective load carrying capacity (ELCC) is the additional load met by an incremental resource while maintaining the same level of system reliability.
- The marginal ELCC is generally calculated by comparing the capacity of storage to the capacity of flat load required to reach an equal loss of load expected, providing a single ELCC that applies to all hours.
- This method is agnostic to peak load hours.
- Other methods have been proposed that aim to improve the accuracy of resource contributions[1] or reduce computational requirements.[2]
- Generally, the ELCC of storage *increases* with higher-duration technologies (e.g., a 6-hour unit has a higher ELCC than a 4-hour unit) or higher levels of renewable energy in the utility system. ELCC *decreases* with incremental storage capacity additions.



Source: 1. A. Mills and P. Rodriguez, [A simple and fast algorithm for estimating the capacity credit of solar and storage](), 2020
2. E3, [Capacity and Reliability Planning in the Era of Decarbonization](), 2020
Graphic: El Paso Electric, [Integrated Resource Plan for the Period 2018-2037](), 2021

Effective load carrying capacity calculations (2)

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- IRPs with dynamic capacity credits adjusted variables such as storage and solar penetration levels, storage duration, technology types (lithium-ion, flow, and pumped hydro), and year of calculation.
- A comparison shows that fixed values are too optimistic to use for all resource penetration levels.
  - Both Xcel and IPL are planning to implement dynamic calculations.
- Besides SCE, ELCC calculations can include all hours of the year, although peak hours have a greater impact on LOLE.
  - There is no clear difference in ELCC between utilities with summer and winter peaks.
  - SCE only used the peak load hour of each month.

Utility	ELCC type	ELCC value
Hoosier	Unknown	Not provided
IPL	Fixed	95%
Vectren	Fixed	95%
APS	Unknown	Not provided
DEC	Dynamic	57% to 100%
PSE	Dynamic	12.4% to 43.8%
SMUD	Unknown	Not provided
Xcel	Fixed	100%
PGE	Dynamic	37% to 94%
El Paso	Dynamic	5%-100%
GMP	Unknown	Not provided
SCE	Fixed, summer peak hours only	Not provided

Source: Cesca Miller, Berkeley Lab

Case study: California PUC's expanded forecasting and modeling (1)

- California's recently re-instituted IRP process is unique in that state utility regulators, who normally just review and respond to utility-filed IRPs, lead development of a unified, statewide reference system plan.
  - 10-year planning horizon
  - Objective: Meet a CPUC-established emissions target (subject to legislative guidance)
  - Load-serving utilities are then required to prepare individual plans identifying their obligations under the reference system plan and their actions for achieving them.

- During the second biennial planning cycle (2019-2020), the CPUC made two modeling enhancements related to storage.
  - Allowed storage resources to provide additional services (spin & non-spin reserve) in the loss of load probability model (SERVM) used to test the reliability of different portfolios
  - Commissioned a third-party study of energy storage potential

Case study: California PUC's expanded forecasting and modeling (2)

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- Ancillary service markets are much shallower than energy and capacity markets. Allowing storage to provide additional services unlocks additional value and potential.

Average hourly values of ancillary services in CAISO (2020)

Hour Ending	Regulation Down	Regulation Up	Spinning Reserve	Non-Spinning Reserve
1	$6.88	$5.22	$1.90	$0.10
2	$5.19	$3.98	$1.47	$0.12
3	$5.93	$3.79	$1.29	$0.11
4	$4.98	$3.65	$1.17	$0.11
5	$5.30	$3.75	$1.33	$0.11
6	$4.96	$4.64	$2.27	$0.12
7	$6.31	$9.15	$5.12	$0.13
8	$10.00	$7.52	$2.94	$0.12
9	$14.18	$6.61	$1.52	$0.14
10	$14.65	$5.94	$1.19	$0.13
11	$16.57	$6.66	$1.12	$0.11
12	$17.61	$7.44	$1.37	$0.11
13	$16.64	$6.65	$1.57	$0.13
14	$17.12	$7.92	$2.03	$0.17
15	$15.85	$8.78	$2.69	$0.51
16	$11.75	$8.93	$3.82	$1.06
17	$10.48	$12.04	$7.50	$2.66
18	$7.91	$22.74	$18.64	$11.09
19	$5.93	$35.06	$31.39	$23.66
20	$5.42	$29.90	$26.37	$16.98
21	$5.64	$13.52	$9.96	$4.10
22	$4.73	$8.74	$5.09	$1.43
23	$6.00	$6.41	$3.07	$0.39
24	$6.70	$5.87	$2.03	$0.12

Hour's most valuable service

Hour's second-most valuable service

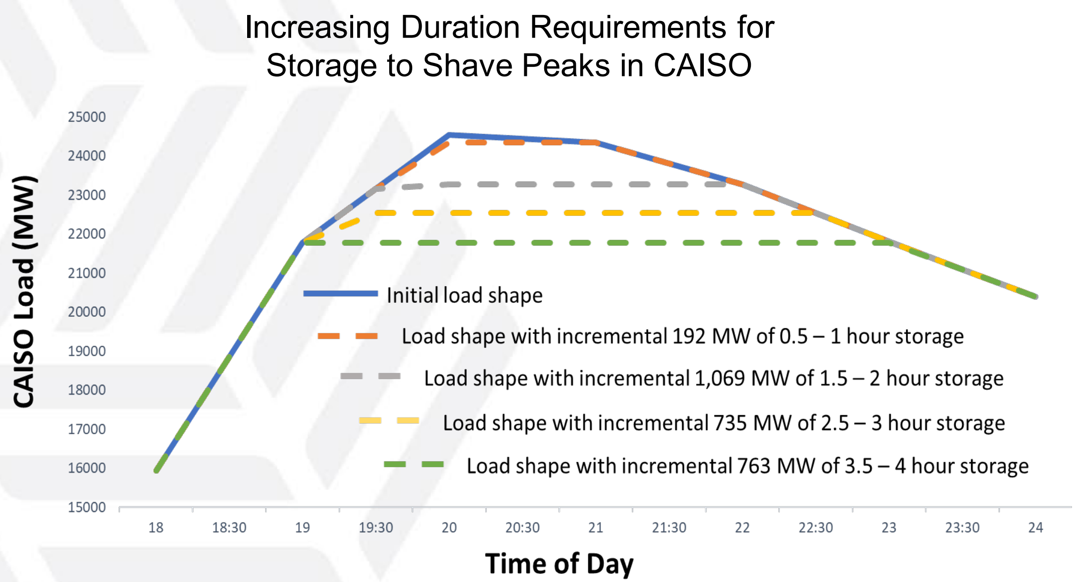
Hour's third-most valuable service

Hour's least valuable service

Source: Twitchell, JB, and Cooke, AL. Forthcoming. "Emerging Best Practices for Modeling Energy Storage in Integrated Resource Plans"

Case study: California PUC's expanded forecasting and modeling (3)

- As more energy storage contributes to peak needs, duration requirements increase.
- To quantify how much 4-hour storage could be cost-effectively deployed when accounting for diminishing returns, CAISO commissioned a third-party storage potential study (Astrape Consulting).
  - Potential studies are a longstanding practice for energy efficiency programs.
  - The study concluded that, assuming the continued rapid growth of solar generation, more than 10 GW of 4-hour storage could be deployed within CAISO by 2030.



Source: Twitchell, JB, and Cooke, AL. Forthcoming. "Emerging Best Practices for Modeling Energy Storage in Integrated Resource Plans"

Storage in IRP Preferred Portfolios

All utilities included some form of storage in their preferred portfolios

	Preferred Portfolio	Primary Drivers
Hoosier	25 MW of generic storage added annually in 2035, 2037, and 2039	Meeting summer peak capacity and reliability goals with renewables; 2023 coal plant retirement
IPL	440 MW of 4-hour storage added from 2023-2039, growing in installments annually	Presence of a carbon tax, high natural gas prices, and early retirement of coal plants
Vectren	126 MW of paired 4-hour storage added in 2023 and 50 MW in 2039	Reduced market exposure risk, cost of carbon taxes, reserve margin, and reliability
APS	Three alternative portfolios, each adding 752 MW of storage by 2024 and between 4.1 GW and 9.8 GW of additional storage by 2035	GHG emissions reduction targets and reliance on new renewable generation in place of merchant PPAs
DEC	Two least cost portfolios (without and with a carbon policy), that include 1.05 GW and 2.2 GW of storage added by 2035 for a combination of 4-hour and 6-hour standalone and hybrid resources	Adopted carbon policy, 70% GHG reduction goal, timing of coal plant retirement, and prohibiting new gas generation
PSE	A combination of Li-ion and flow batteries; 75 MW of storage by 2025, an additional 125 MW by 2030, and an additional 550 MW by 2045	Improving flexibility with DER penetration, social cost of carbon and carbon taxes, electrification, and 2026 coal plant retirement

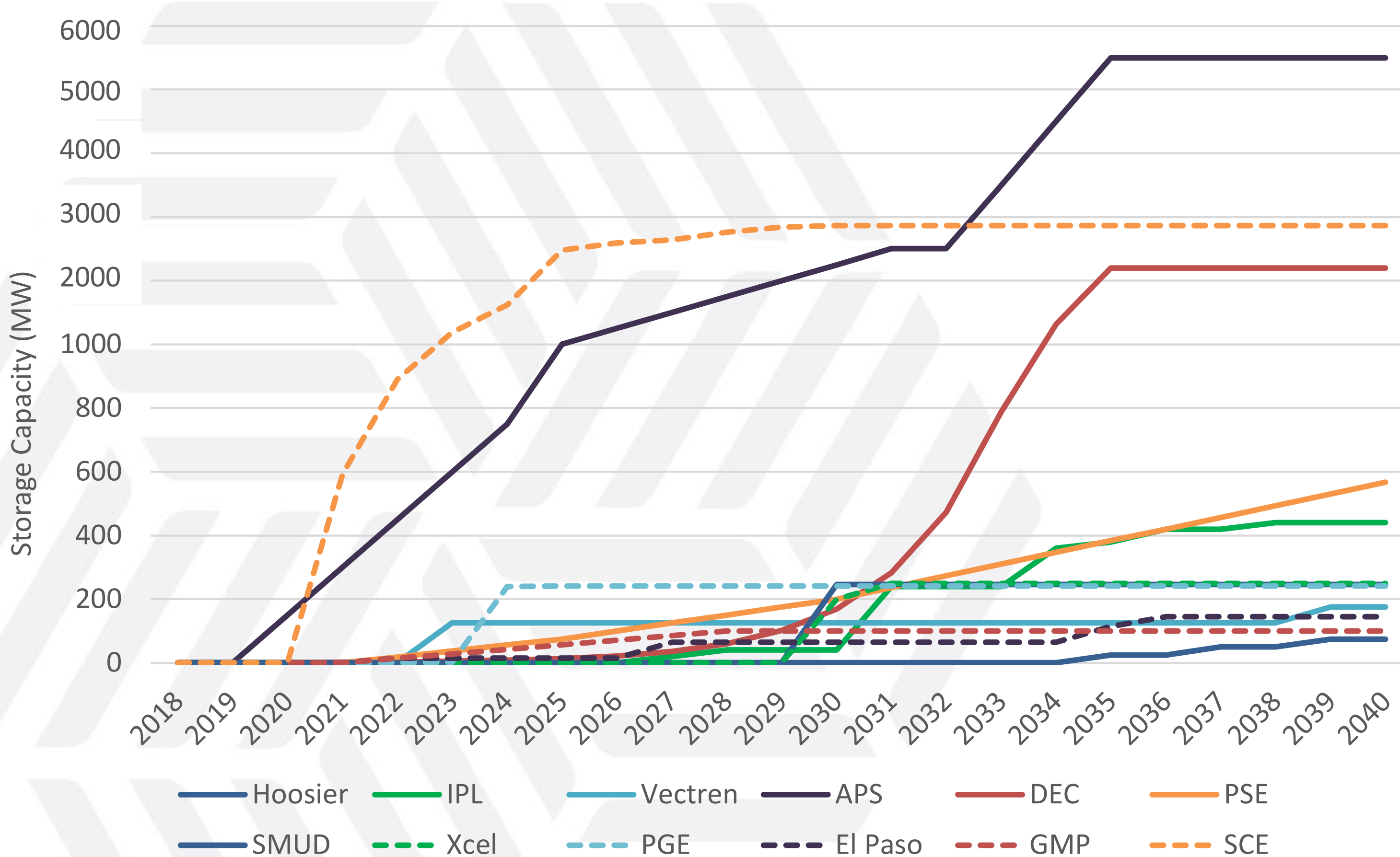
Source: Cesca Miller, Berkeley Lab

All utilities included some form of storage in their preferred portfolios

	Preferred Portfolio	Primary Drivers
SMUD	246 MW of 4-hour storage added in 2030	Competitive costs with capacity market purchases and GHG reduction levels
Xcel	200 MW of storage added in 2030 and 50 MW of storage added in 2031	Retirement of coal plants, carbon reduction goals, and resource adequacy
PGE	Three alternative portfolios each adding 37 MW of utility-scale 6-hour batteries, 200 MW of pumped storage, and 2.2 MW to 11.2 MW of dispatchable customer-sited storage	Technology costs, load growth, decarbonization goals, customer adoption, availability of dispatchable resources, renewable resource additions
El Paso	145 MW of 4-hour standalone and hybrid storage added between 2022 and 2036	Load growth, fuel costs, and carbon taxes
GMP	Illustrative Future Portfolio includes 50 MW to 100 MW of energy storage and other flexible sources, which is a combination of estimated utility-scale and distributed storage	Customer adoption, peaker plant retirements, prevalence of T&D congestion, resiliency requirements
SCE	The Preferred Conforming Portfolio adds 2,861 MW of 4-hour storage procured from 2021 through 2030	CPUC ruling requirement to procure resource adequacy capacity (D.19-11-016), additional system reliability, and GHG reduction targets

Source: Cesca Miller, Berkeley Lab

Cumulative energy storage additions in preferred portfolios

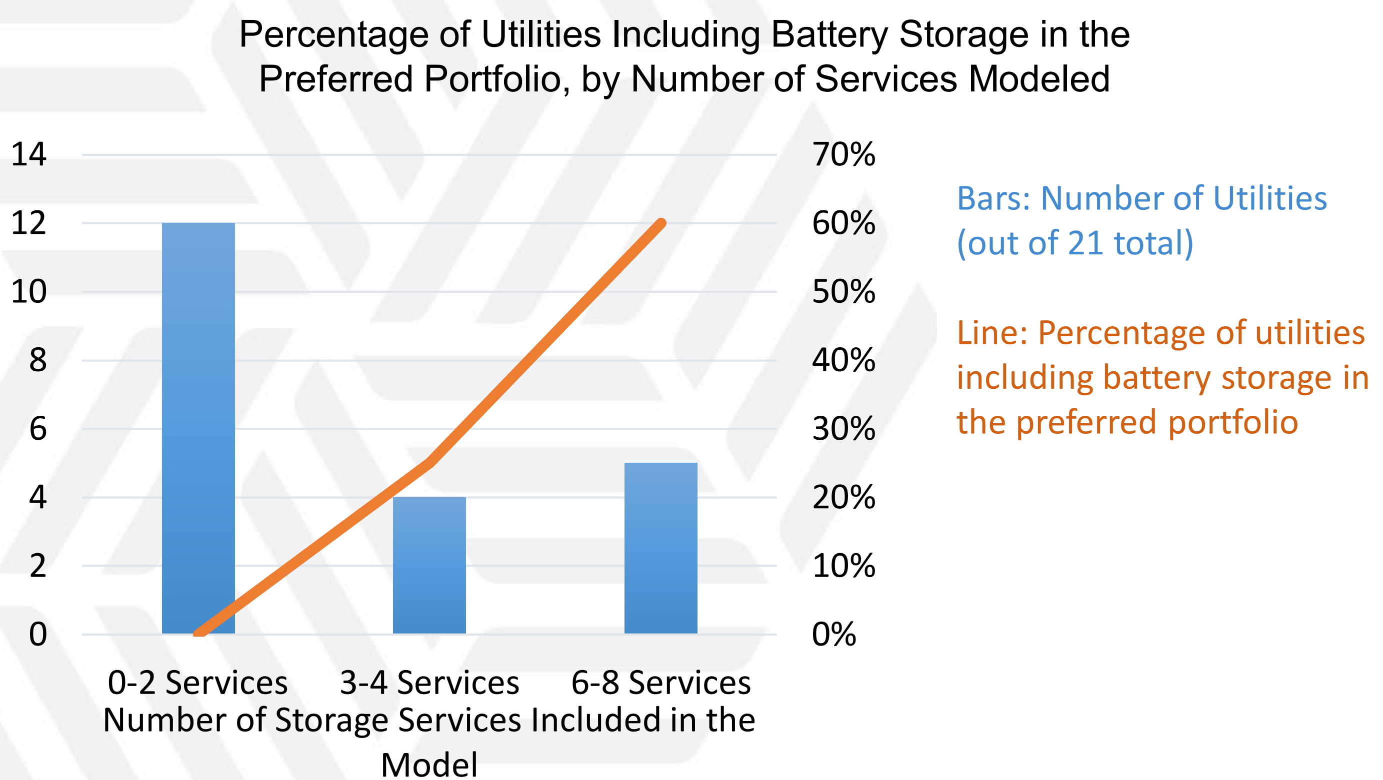


Where IRPs did not identify a preferred portfolio, the chart shows the capacity for the mid-range portfolio (APS, DEC, Xcel, PGE).

Source: Cesca Miller, Berkeley Lab

Storage selection is more likely when utilities consider more grid services

- As utilities account for more grid services provided by energy storage, the likelihood of storage being selected in the preferred portfolio increases.

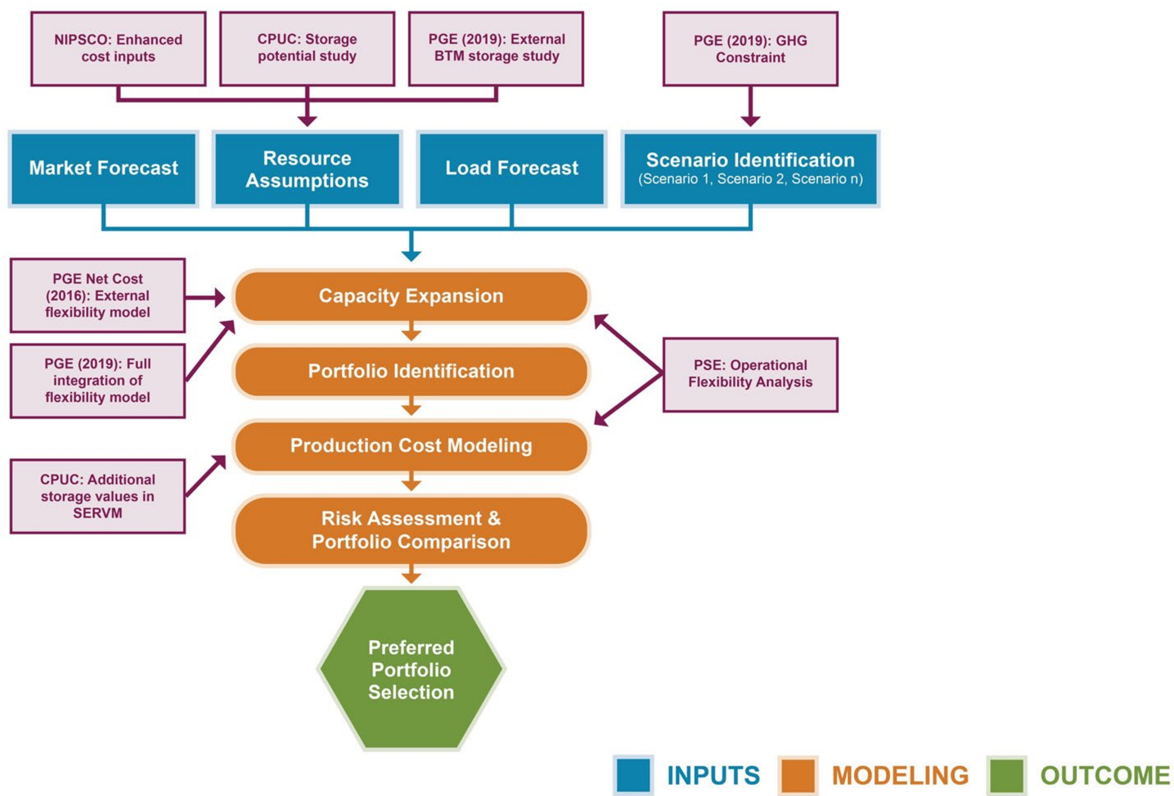


Source: Cooke, A.L., Twitchell, J.B., O'Neil, R.S. 2019. *Energy Storage in Integrated Resource Plans*. PNNL.

Opportunities for Improvements

Multiple avenues for improving representation of storage in IRPs

- The complex nature of an IRP creates multiple points of entry for improving storage modeling.



Source: Twitchell, JB, and Cooke, AL. Forthcoming. “Emerging Best Practices for Modeling Energy Storage in Integrated Resource Plans”

The state of storage in utility IRP portfolios

- Utility innovation in modeling energy storage is accelerating, but not widely adopted.
  - Much of the activity centered in the Western U.S., where utilities have made evolutionary changes over the last two or three planning cycles.
  - Limited adoption in Southeast states
  - Several Southeastern utility IRPs have selected storage in recent cycles (e.g., Duke Energy, Georgia Power, Florida Power & Light), but IRPs are lean on analytical details.

- IRP transparency is improving, but there is room for improvement.
  - As IRPs form the “paper trail” for subsequent investments and rate recovery, utilities are increasingly providing extensive narratives about modeling approaches and conclusions.
  - Where storage is selected without supporting modeling, the process breaks down and regulatory processes are challenged.
  - Cost assumptions remain an area of limited transparency.

Recommendations for improving evaluation of storage in IRPs

- Transparent and standardized approach to defining storage costs, adoption, and other modeling assumptions
  - Additional mature storage technology types (e.g., emerging chemistries, longer durations) and hybrid resources (solar and/or wind plus storage)
- Clearer descriptions of storage modeling methodologies, including:
  - How utility customer adoption of distributed storage is included in load forecasts
  - How storage is dispatched alongside other resources
  - Definition of grid services (e.g., frequency, spinning reserves) and clarity about which grid services are modeled
- Application of enhanced models and methods that can more accurately capture storage value (e.g., sub-hourly dispatch, reliability and flexibility value)
  - Modeling of additional grid services that storage can provide
  - Dynamic ELCC calculations for storage capacity value; exploration of potential other calculation methods (e.g., applying monthly ELCC values or using peak hours only)
- Distributed storage as a selectable resource in capacity expansion modeling
- Integration of distribution system benefits of storage

Consistent and transparent assumptions

- Use a standard, transparent approach and reporting template to document energy storage costs, adoption, and other modeling assumptions in IRPs, including:
  - Cost component values (e.g., battery module, inverter, balance of system, EPC, O&M, and interconnection) with sufficient detail to enable stakeholders to reproduce capital cost calculations
    - Additional detail could include the energy throughput assumed to calculate variable O&M costs or a battery module replacement schedule.
  - Description of the logic used to select cost assumptions and evolution of costs over time (e.g., more or less aggressive cost reduction curves)
  - Financial benefits—by individual grid service if available—used to determine economic feasibility of storage (e.g., system reliability and capacity reserve requirements)
  - Description of how storage capacity is dispatched for competing grid services (e.g., capacity and balancing reserves)
  - If multiple storage technologies are modeled (e.g., lithium-ion and flow batteries), documentation of how modeling approaches capture technical differences (e.g., roundtrip efficiency, ramp rates, degradation, cycle life)

Defined modeling methodology

- Clearly define storage technology types, operational parameters, and quantities included, and provide detail of how storage is modeled in all IRP components
  - Describe how storage is dispatched for capacity expansion and production cost models as competitive technology alongside other resources
  - Explain in detail the adoption forecast model employed to predict BTM storage penetration and the model(s) used to simulate the operational modes
  - Explain how the operational profile of BTM storage is aggregated and its impact on net customer load, demonstrating that there is no double-counting of storage capacity in: (1) net load forecasts and (2) resources

Enhanced models and methods

- Use additional tools (e.g., sub-hourly production cost models, effective load carrying capacity studies, and resource adequacy models) to more accurately capture benefits from storage (e.g., flexibility, ancillary services, and ELCC) and other electricity resources, rather than simply use assumed values in capacity expansion models or omit values entirely
  - These additional tools could more accurately assess value streams and dispatch for storage, improving its relative cost-effectiveness compared to other resources.
  - These tools also could improve resource adequacy assessment and representation of renewable energy sources.

Distributed storage as a selectable resource

- Integrate potential customer- and third party-owned BTM storage into capacity expansion models, rather than simply reflecting current levels of customer adoption.

  - Explicitly include BTM storage as an input to the IRP model, whether owned by the utility, customers or third parties—specifically, various adoption levels and operational strategies

  - Allow the capacity expansion planning model to select storage as a resource in order to evaluate its economic value under various control strategies for providing grid services (e.g., frequency support, regulation, peaking capacity) to meet utility system needs

- Model results can serve as the basis for related activities, including aligning customer program incentives and rate designs with their economic value to utilities.

Integration of distribution system benefits

- Integrate distribution system benefits into analysis of avoided costs from storage resources

  - Utilities need to be able to evaluate multiple resource portfolio options in an organized, holistic, and technology-neutral manner across generation, distribution, and transmission systems.
  - Storage can be used to avoid distribution system losses when they are highest, resulting in reduced transmission system losses and avoided generator capacity needs. Locational impacts on the distribution system and their associated economic value should be modeled and calculated first. Results can be used to adjust inputs for the analysis of transmission and generation system values.
  - Improved integration of distributed storage requires enhanced analytical capabilities in distribution system planning that can feed into bulk system analysis — for example:
    - Conduct hosting capacity analysis to determine system limitations
    - Perform energy analysis to account for marginal distribution system losses
    - Identify feeders with potential locational value of adding storage capacity
    - Estimate systemwide avoided cost of deferred distribution capacity expansion

Source: T. Eckman, L. Schwartz, and G. Leventis, Determining Utility System Value of Demand Flexibility From Grid-interactive Efficient Buildings, 2020

Future of storage in utility IRP portfolios

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- IRP filings occur at regular intervals, commonly every 2-3 years. Future filing cycles provide opportunities to consider new storage technologies as they mature, as well as improved storage assumptions and methodologies.
- Utilities identify near- and long-term activities in IRP action plans, including utility-owned storage projects in development and roll-out of BTM customer programs. Examples of near-term opportunities identified in IRPs include the following:
  - APS will incorporate demand-side storage programs into future load forecasts, as well as consider a broader range of storage technology types.
  - Xcel Energy and IPL will explore more dynamic ELCC calculations.
  - Xcel also will explore how customer-sited storage that is currently non-dispatchable could be incorporated into resource adequacy modeling and incentivized to provide grid services.
  - PSE will incorporate potential storage benefits from a regional resource adequacy program in development.
  - PGE will analyze the locational value of distributed storage as well as explore cost requirements and impacts of large-scale storage.

Questions states can ask

- What storage technologies are included in the IRP? Does the IRP include hybrid systems (storage + solar, storage + wind, storage + gas) as well as standalone systems?
- What model inputs are used to capture technical differences in storage technology types?
- Are utility-scale storage capacity and duration included as variables within the model that can be optimized (in contrast to fixed values)?
- Are customer-sited resources modeled as resource options in capacity expansion models?
- If distributed storage incentive programs are available to utility customers, how is customer adoption based on these programs factored into load forecasts and resource planning?
- What sources are used for cost assumptions, and how are reference costs adjusted to create model inputs (e.g., adjusting for local interconnection and labor costs or forecasting future price declines)?
- What grid services are used to calculate operational and economic storage benefits (e.g., capacity, energy, ancillary services, flexibility)?
- Were locational values of storage modeled?
- Is storage modeled for intra-hourly applications (e.g., ancillary services and flexibility)?
- What inputs and drivers are impacting energy storage economics (e.g., roundtrip efficiency, ELCC, grid service participation, and cost assumptions)?
- How does the amount of storage in the utility's tested portfolios and preferred portfolio compare to other U.S. utilities? What explains the differences?

Resources for more information

- Cooke, A.L., Twitchell, J.B., O'Neil, R.S. 2019. Energy Storage in Integrated Resource Plans. PNNL.
- Cole, W., Frazier, A. W. 2020. Cost Projections for Utility-Scale Battery
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- Twitchell, J.B., and Cooke, A.L. Forthcoming. "Emerging Best Practices for Modeling Energy Storage in Integrated Resource Plans."
- U.S. Energy Information Administration. 2020. Battery Storage in the United States: An Update on Market Trends.

Thank you

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Extra Slides

IRPs reviewed by LBNL

Utility	State	Analysis Years	Title and Link
Hoosier Energy	Indiana	2021-2040	Hoosier Energy 2020 Integrated Resource Plan – Public Version Volume I: Main Report
Indianapolis Power and Light	Indiana	2020-2039	Indianapolis Power and Light Company 2019 Integrated Resource Plan
Vectren	Indiana	2021-2039	2019/2020 Integrated Resource Plan
Arizona Public Service	Arizona	2020-2035	2020 Integrated Resource Plan
Duke Energy Carolinas	North Carolina and South Carolina	2021-2035	Duke Energy's 2020 Integrated Resource Plan
Puget Sound Energy	Washington	2022-2045	2021 PSE Integrated Resource Plan
Sacramento Municipal Utility District	California	2020-2030	Resource Planning Report
Xcel	Minnesota	2020-2034	Upper Midwest Integrated Resource Plan 2020-2034, Supplement 2020-2034 Upper Midwest Resource Plan Reply Comments
Portland Gas and Electric	Oregon	2019-2030	Integrated Resource Plan: July 2019
El Paso Electric	Texas	2018-2037	Integrated Resource Plan for the Period 2018-2037
Green Mountain Power	Vermont	2019-2035	2018 Integrated Resource Plan
Southern California Edison	California	2020-2030	Integrated Resource Plan of Southern California Edison