

Distributed Energy Resources in Distribution System Planning

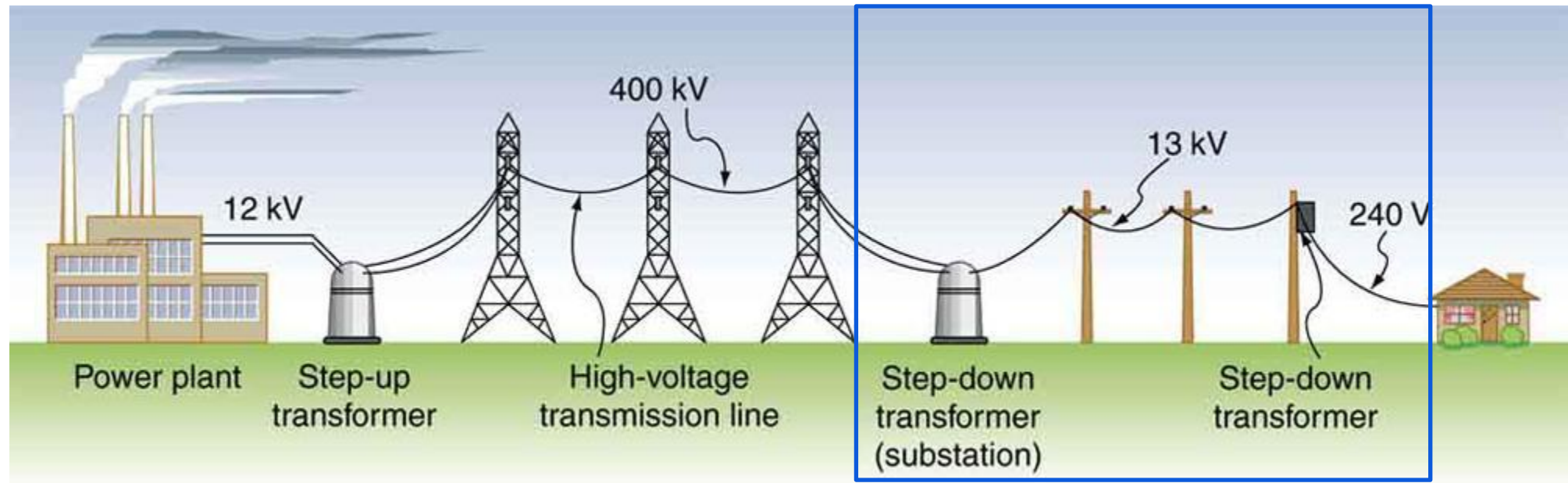
DOE Energy Innovator Fellows Boot Camp

Sean Murphy
October 9, 2025



Energy Technologies Area
BERKELEY LAB

Where are we in the power system?



Source: electricalacademia.com



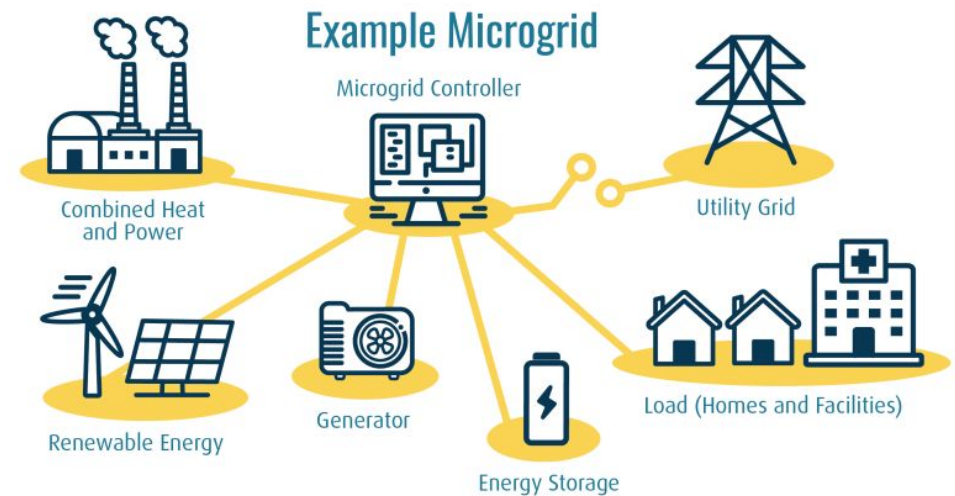
Content

- Defining distributed energy resources (DERs) and distribution system planning
- DER forecasting
- Interconnection
- Hosting capacity analysis
- Distribution-level grid services



What are DERs?

- DERs are energy assets sited close to energy consumers. DERs provide all or some of the host facility's immediate power needs and can support the utility system by reducing demand or providing energy, capacity, and ancillary services.*
- DERs may be in front-of-the-meter (e.g., a utility battery at a substation) or behind-the-meter (e.g., rooftop solar)
- DERs include but are not limited to:
 - Demand response (including time-varying rates)
 - Energy efficiency
 - Gas and diesel generators
 - Rooftop and community solar
 - Battery storage
 - Microgrids



Source: [NASEO Microgrids State Working Group](#)

*NARUC definition: A DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load.

Forecasting DERs

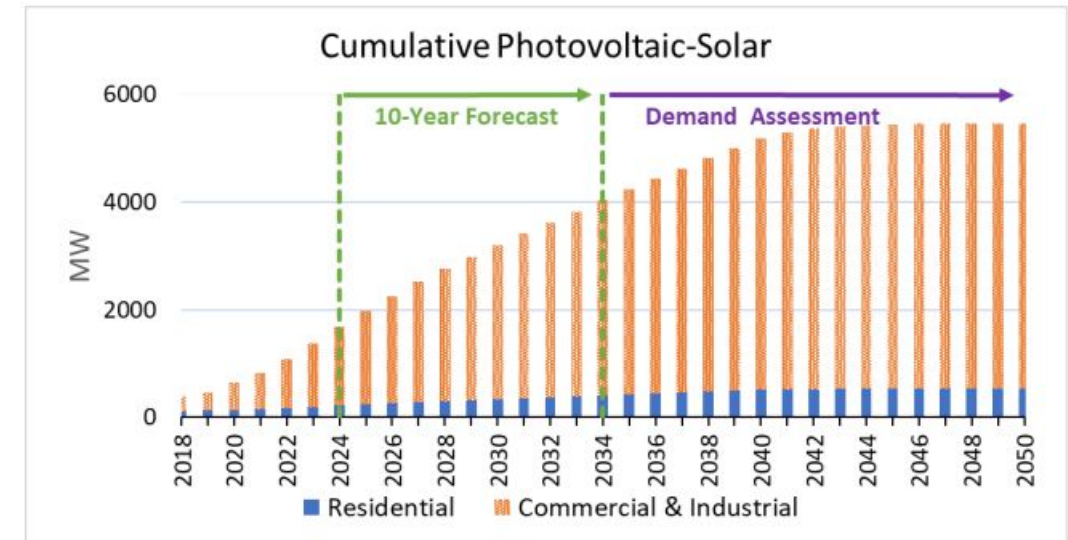


What is load forecasting and how do DERs fit in?

- Utilities estimate peak demand at specific locations on the distribution system to inform the timing, need, and type of distribution system investments over a 5 year-plus timeframe.
- *Gross* load forecasts estimate peak demand based on historical relationships between load, weather, economic, and demographic variables. They do not account for the impacts of weather-driven DERs (e.g., solar and wind), energy efficiency or demand response.
- The forecasting process considers load modifiers such as various types of DERs.
 - Including changes in customer usage patterns (e.g., EV charging may increase load on transformers at atypical times).
 - As DER adoption increase, utilities need a better understanding of the impact on distribution systems.
- Distribution-level load forecasts inform investment decisions, hosting capacity analyses, and sourcing of DER grid services

DER forecasting – Modeling DER adoption

- Utilities can estimate systemwide DER adoption
 - Systemwide adoption may reflect state targets or requirements
 - Diffusion models (e.g., Bass) can be used to predict adoption and penetration rates
- Utilities can allocate adoption to feeders based on:
 - Number of customers or load on a feeder proportional to systemwide values
 - Propensity models that predict the likelihood of adoption within the feeder
- National Grid New York estimates PV adoption at the:
 - *System-level* based on historical interconnection rates and state-level targets
 - *Feeder-level* based on interconnection queue for PV and a propensity model using socioeconomic and energy data

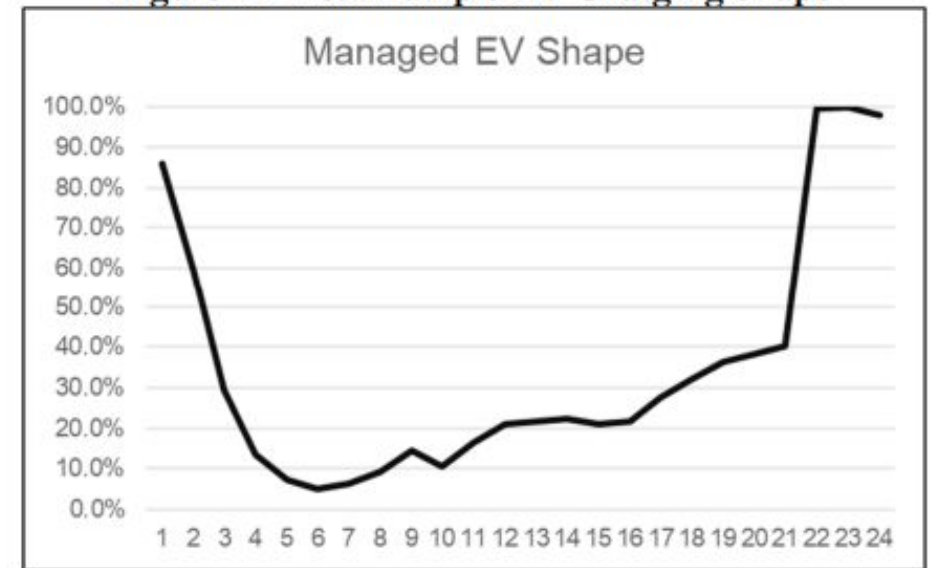


Source: [National Grid](#)

DER forecasting – Modeling DER operations

- Modeling assumptions for DER operations can impact distribution-level load forecasts
- For example, key parameters that affect the load shape of managed EV charging include:
 - The type of electric vehicle (EV), vehicle miles traveled, and fuel efficiency
 - Ambient temperature
 - The hours in which charging is managed
 - The object of the charging strategy (e.g., minimize evening peak)
- Whether battery storage is optimized to minimize cost or maximize backup power affects its load shape

Figure A1 - 18: Example EV Charging Shape



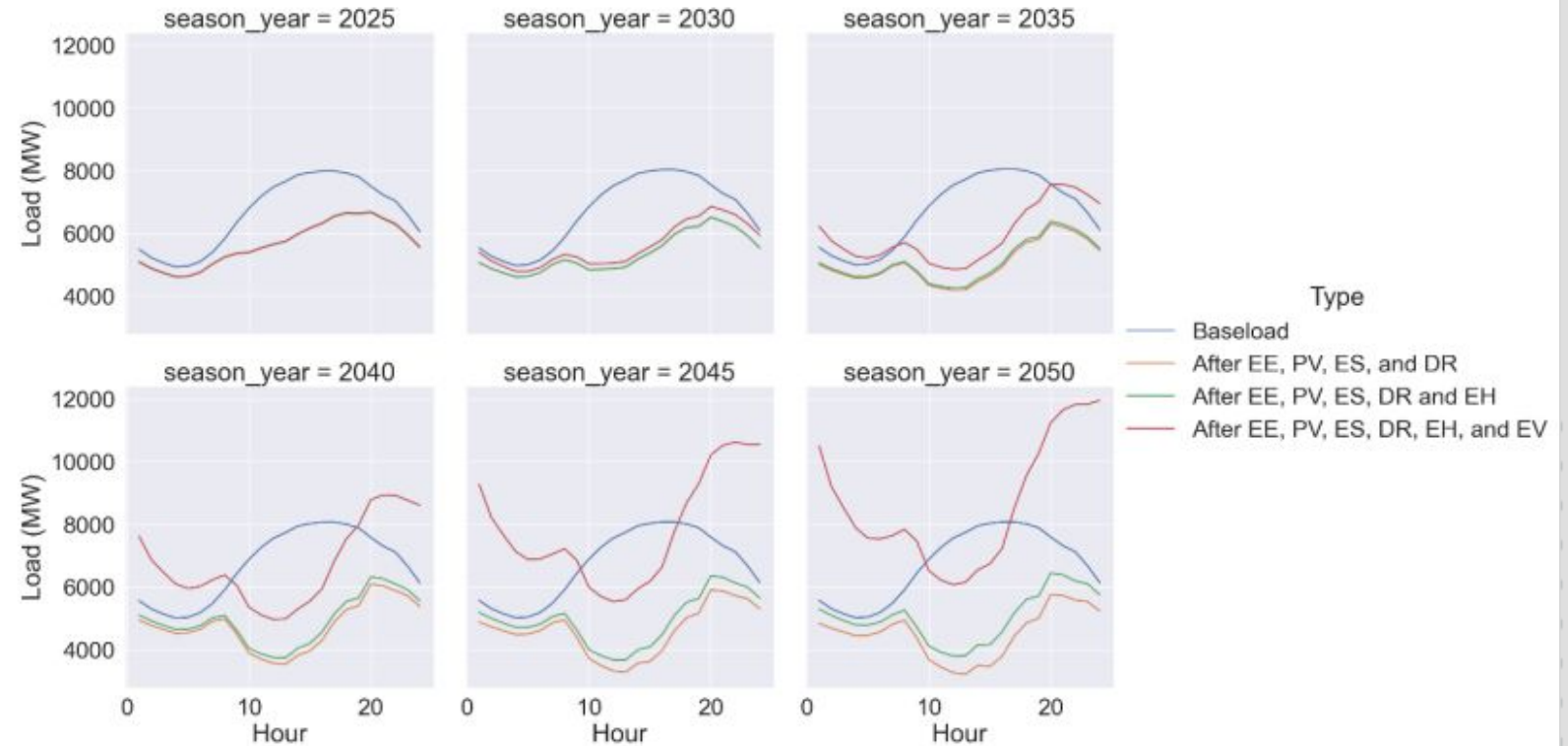
Source: [Xcel Energy Minnesota 2023 Integrated Grid Plan](#)

DER forecasting – Temporally granular DER forecasts (1)

- Using hourly DER load shapes in distribution-level load forecasting helps:
 - Estimate changes in the timing and magnitude of peak demand and minimum demand for individual feeders
 - Identify potential constraints
 - Load remaining at high levels for extended periods may create [thermal risks](#) in distribution system infrastructure
 - Peaks may vary across locations on the distribution system and may not be coincident with system peak demand
- Load shapes can leverage both modeled and empirical data, including data sources such as the following:
 - [EVI-Pro/Pro-Lite](#) or metering data for managed EV charging
 - [ResStock](#) and [ComStock](#) for energy efficiency
 - [PV Watts](#) for solar photovoltaics
 - Impact evaluations of demand response programs
 - [LoadSEER](#) (load shapes are part of a broader forecasting platform)

DER forecasting – Temporally granular DER forecasts (2)

- National Grid New York provides hourly peak day load shapes for the summer peak day over its forecast period that:
 - Exclude all DERs (Baseload in blue)
 - Account for energy efficiency, rooftop PV, energy storage, and demand response (orange)



Source: [National Grid](#)

DER forecasting– Managing uncertainty

- Utilities can manage uncertainty in DER forecasting through scenario analysis and probabilistic methods
- Hawaiian Electric uses discrete scenarios of DER adoption (see figure)
- [National Grid New York](#) considers the probability of different DER adoption scenarios in its feeder-level forecasts

Modeling Scenario	Purpose	DER Forecast	EV Forecast	EE Forecast	Non-DER/EV TOU Forecast	EV Load Shape	Fuel Price Forecast	Resource Potential
Base	Reference scenario.	Base	Base	Base	Base	Managed EV charging	Base	NREL Alt-1
Land-Constrained	Understand the impact of limited availability of land for future solar, onshore wind and biomass development.	Base	Base	Base	Base	Managed EV charging	Base	Land-Constrained Resource Potential
High Load	Understand the impact of customer adoption of technologies for DER, EVs, EE and TOU rates that lead to higher loads.	Low	High	Low	Low	Unmanaged EV charging	Base	NREL Alt-1
Low Load	Understand the impact of customer adoption of technologies for DER, EVs, EE and TOU rates that leads to lower loads.	High	Low	High	High	Managed EV charging	Base	NREL Alt-1
Faster Technology Adoption	Understand the impact of faster customer adoption of DER, EV and EE.	High	High	High	High	Managed EV charging	Base	NREL Alt-1
Unmanaged Electric Vehicles	Understand the value of managed EV charging relative to unmanaged.	Base	Base	Base	Base	Unmanaged EV charging	Base	NREL Alt-1
DER Freeze	Understand the value of the distributed PV and BESS uptake in the Base forecast. Informative for program design and solution sourcing.	DER Freeze	Base	Base	Base	Managed EV charging	Base	NREL Alt-1
Electric Vehicle Freeze	Understand the value of the electric vehicle's uptake in the Base forecast. Informative for program design and solution sourcing.	Base	EV Freeze	Base	Base	Managed EV charging	Base	NREL Alt-1
High Fuel Retirement Optimization	Understand the impact of higher fuel prices on the resource plan while allowing existing firm unit to be retired by the model.	Base	Base	Base	Base	Managed EV charging	EIA High Fuel Price	NREL Alt-1
Energy Efficiency Resource	Understand the value of energy efficiency as a resource. Informative for program design and solution sourcing.	Base	Base	EE Freeze + EE Supply Curves	Base	Managed EV charging	Base	NREL Alt-1

Source: [Hawaiian Electric 2023 Integrated Grid Plan](#)

Hosting capacity analysis

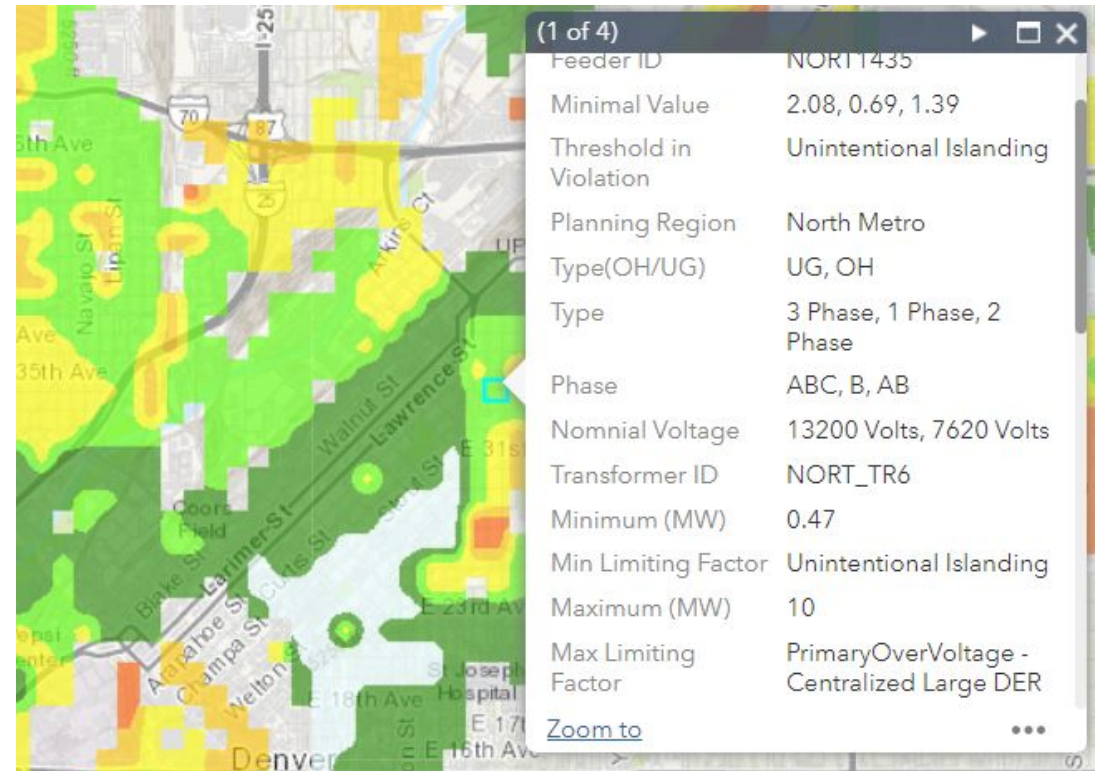


What is hosting capacity analysis?

- Hosting capacity analysis determines the amount of DERs that can interconnect at a specific point on the distribution grid without:
 - Infrastructure upgrades or
 - Adversely impacting power quality or reliability under existing control and protection systems
- The analysis informs the siting, sizing, and operations of DERs
- Estimates of hosting capacity can be specific to generation, load (including EVs), and storage

Hosting capacity maps

- Utilities often report hosting capacity in maps but may also provide downloadable spreadsheets and application programming interfaces (e.g., [ConEdison](#))
- Maps may present hosting capacity in ranges (“heat map”) or values specific to distribution system equipment such as transformers
- Maps also may include data on distribution system equipment attributes such as transformer voltage



Source: [Xcel Energy Colorado hosting capacity map](#)

Hosting capacity analysis leading practices

- Utilities can document the:
 - Types of constraints to hosting capacity considered in the analysis
 - Thresholds for each constraint
- Utilities can identify strategies to mitigate these constraints and provide cost estimates
- Publicly available granular data support better decision-making by DER developers and utility regulators

Category	Impacts	Mitigation
Voltage	Over-voltage	Adjust DER power factor setting, reconductor
	Voltage Deviation	Adjust DER power factor setting, reconductor
	Equipment Voltage Deviation	Adjust DER power factor setting, adjust voltage regulation equipment settings (if applicable), or reconductor
Loading	Thermal Limits	Reconductor, replace equipment
Protection	Additional Element Fault Current	Adjust relay settings, replace relays, replace protective equipment
	Breaker Relay Reduction of Reach	Adjust relay settings, replace relays, move or replace protective equipment
	Sympathetic Breaker Relay Tripping	Adjust relay settings, replace relays, move or replace protective equipment
	Unintentional Islanding	Installation of Voltage Supervisory Reclosing

Source: [Xcel Energy 2024 Hosting Capacity Guidebook](#)

Distribution-level grid services



DERs can provide distribution-level grid services

- Distribution capacity
 - Managing load on distribution system infrastructure (e.g., a feeder transformer)
- Voltage management
 - Maintaining voltage levels and bandwidths within acceptable levels
- Reliability
 - Improving grid reliability and providing energy during system outages
- Power quality
 - Limiting power harmonics and voltage fluctuations that cause flicker



Source: [UTB Transformers](#)

Grid services adapted from [De Martini et al. 2024](#) and [Murphy et al. 2025](#)

There are multiple ways to source distribution-level grid services from DERs

- Pricing
 - Time-varying rates and DER-specific tariffs such as net metering
- Programs
 - Demand response and energy efficiency programs
- Procurement
 - Competitive process for non-wires alternatives (NWAs) for deferring or avoiding infrastructure investments

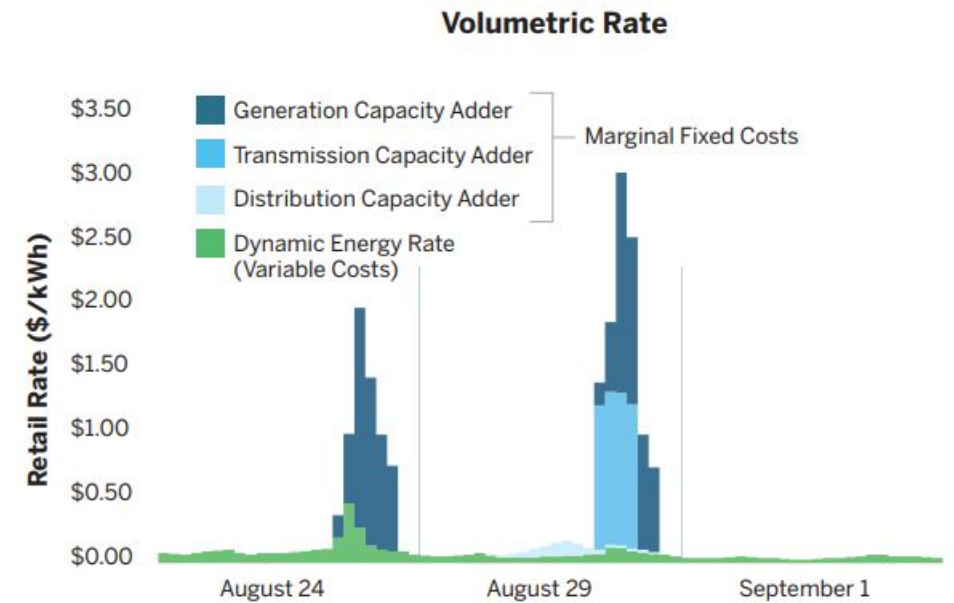


Sources: Newport Consulting and North Carolina DSIRE Program

States with pricing, programs, or procurements that address distribution-level grid services

Sourcing DER distribution-level grid services – Pricing (1)

- Utilities can [design rates](#) that address distribution capacity and incentivize reducing load during peak demand hours for distribution system infrastructure
 - Rates can reflect the long-run marginal cost of distribution system investments
 - Rates can incorporate demand charges (\$/kW) and volumetric adders (\$/MWh)
- ConEdison [Smart Home rate](#) includes demand charges during distribution peak events



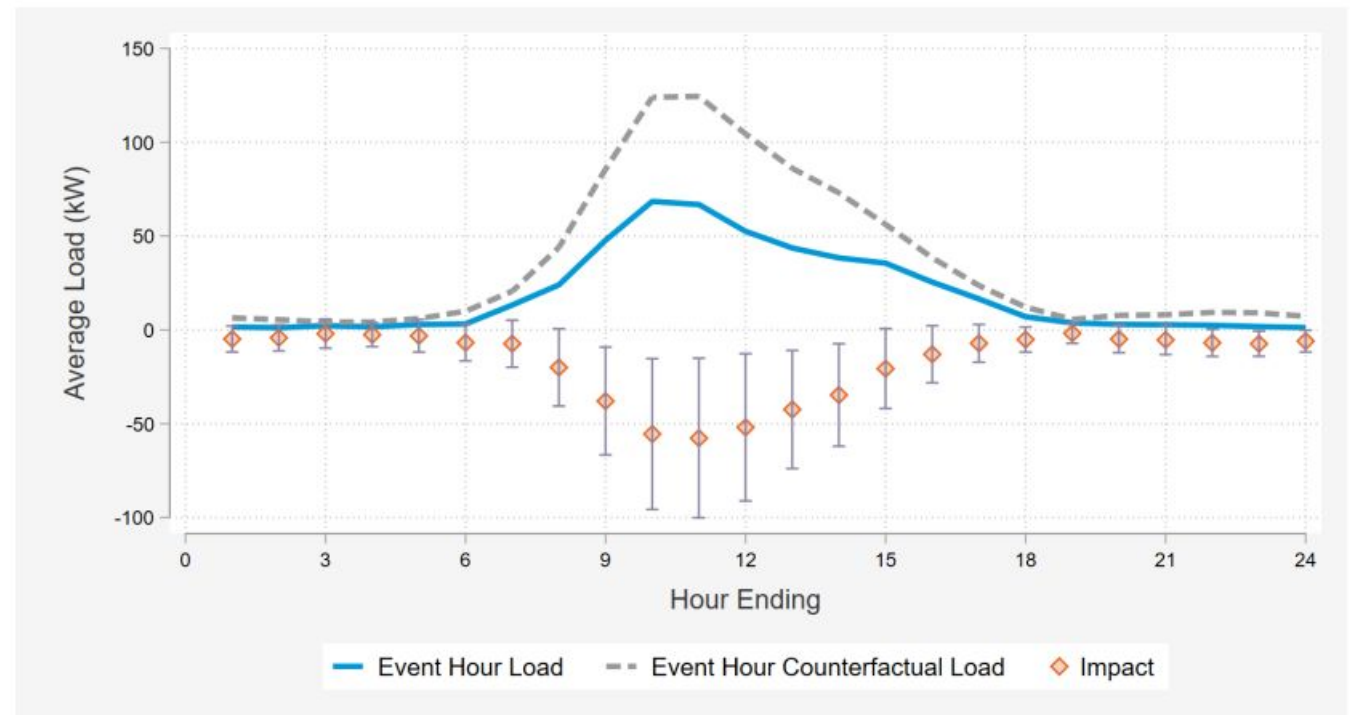
Source: [Olsen et al. 2023](#)

See Carvallo and Schwartz (2023), [The use of price-based demand response as a resource in electricity system planning](#)

Sourcing DER distribution-level grid services – Pricing (2)

- San Diego Gas & Electric [Electric Vehicle Integration rate](#)
 - Applies to Level 2 chargers
 - Dynamic rate with a distribution adder that applies to the 200 hours in which a feeder has the highest load historically
 - The distribution adder *increases* when the utility calls an event during high load hours
 - Events reduce load on feeders

Average hourly impact of feeder-level events for Level 2 workplace chargers

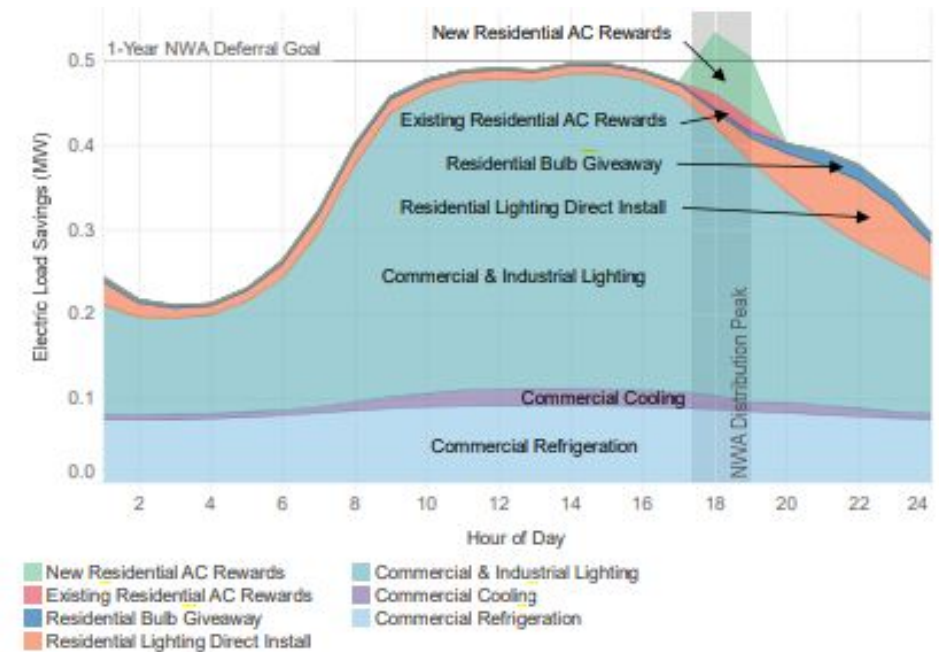


Source: [SDG&E 2025](#)

Sourcing DER distribution-level grid services - Programs

- Utilities use geotargeted DER programs to reduce load growth and the need for upgrades for specific parts of the distribution system
 - Programs can provide incentives for the adoption of DERs or improved operation of existing DERs
- Geotargeted programs require a defined grid need (e.g., hours and magnitude of load reduction)

Estimated peak day load impacts of Xcel Energy Minnesota Geotargeted Clean Energy Initiative

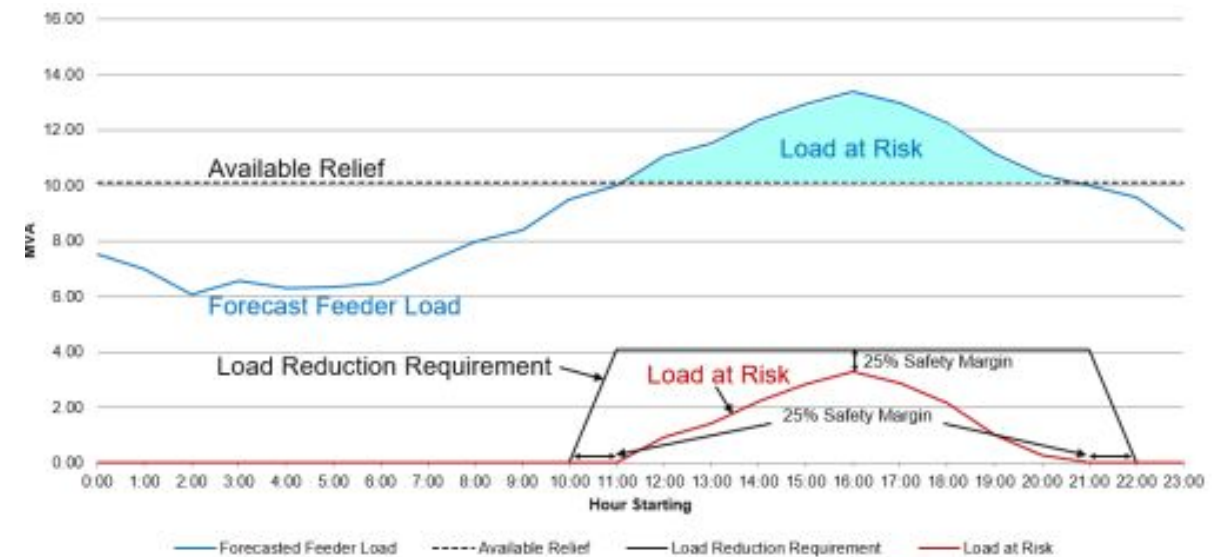


Source: [Center for Energy and Environment 2021](#)

Sourcing DERs for distribution-level grid services – Procurement (1)

- Utilities can use competitive bidding processes to procure NWAs
- NWAs are DERs that provide distribution *capacity services* by reducing, deferring, or avoiding the need for some upgrade projects on specific parts of the distribution system
- DERs can provide *reliability services* by shortening or avoiding outages

Illustrative requirements for load relief using an NWA



Source: [Xcel Energy Colorado Distribution System Plan 2022](#)



Sourcing DERs for distribution-level grid services – Procurement (2)

- Preliminary utility assessment
 - Whether the distribution system need is suitable in terms of type, timing, and cost
- The utility issues a request for proposals that characterizes the grid need (e.g., duration and magnitude of capacity need) and specifies bid evaluation and selection criteria
 - Includes requirements for DER operation to address grid need
- Ex post evaluations can assess DER performance for addressing the specified grid need

Criteria	Potential Elements Addressed	
Project Type Suitability	Project types include Load Relief or Load Relief in combination with Reliability.	
Timeline Suitability	Large Project (Projects that are on a major circuit or substation and above)	<ul style="list-style-type: none"> ● 36 to 60 months
	Small Project (Projects that are feeder level and below)	<ul style="list-style-type: none"> ● 18 to 24 months
Cost Suitability	Large Project (Projects that are on a major circuit or substation and above)	<ul style="list-style-type: none"> ● No cost floor
	Small Project (Projects that are feeder level and below)	<ul style="list-style-type: none"> ● Greater than or equal to \$450,000

Source: [Consolidated Edison Distribution System Implementation Plan 2023](#)

Contact

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DERs in Bulk Power Systems

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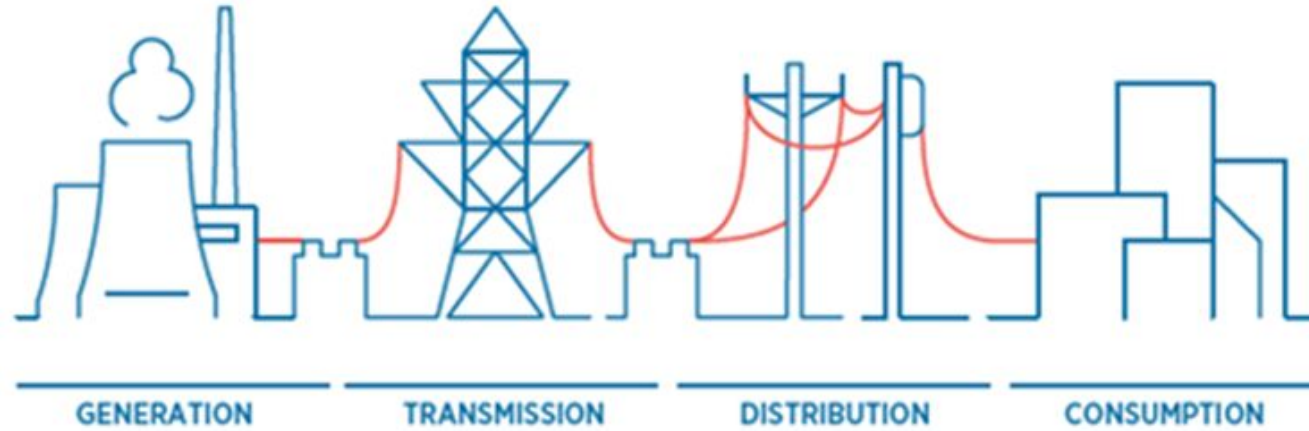
Juan Pablo Carvallo

October 9, 2025



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Where are we in the system?



Vertically integrated jurisdictions



Restructured jurisdictions



Content

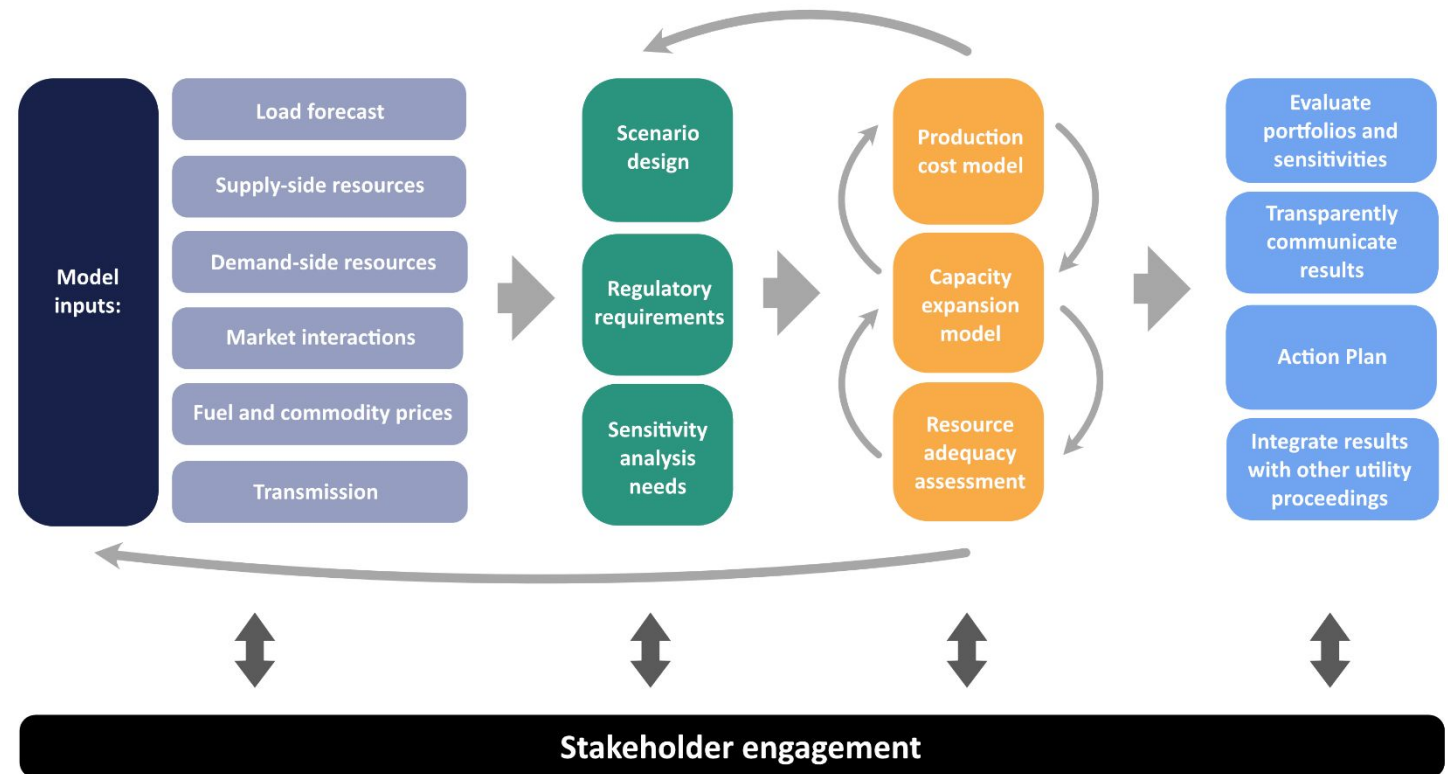
- Integrated Resource Planning (IRP) in one slide (well, three)
- DERs in IRP
 - Practices for forecasting DERs
 - Example of modeling DERs in IRP: price-based demand response
- Integrated system planning
- Wholesale markets
 - FERC Order 2222



IRP– The process, the plan, the document

IRPs generally seek to find the least-cost resource plan subject to:

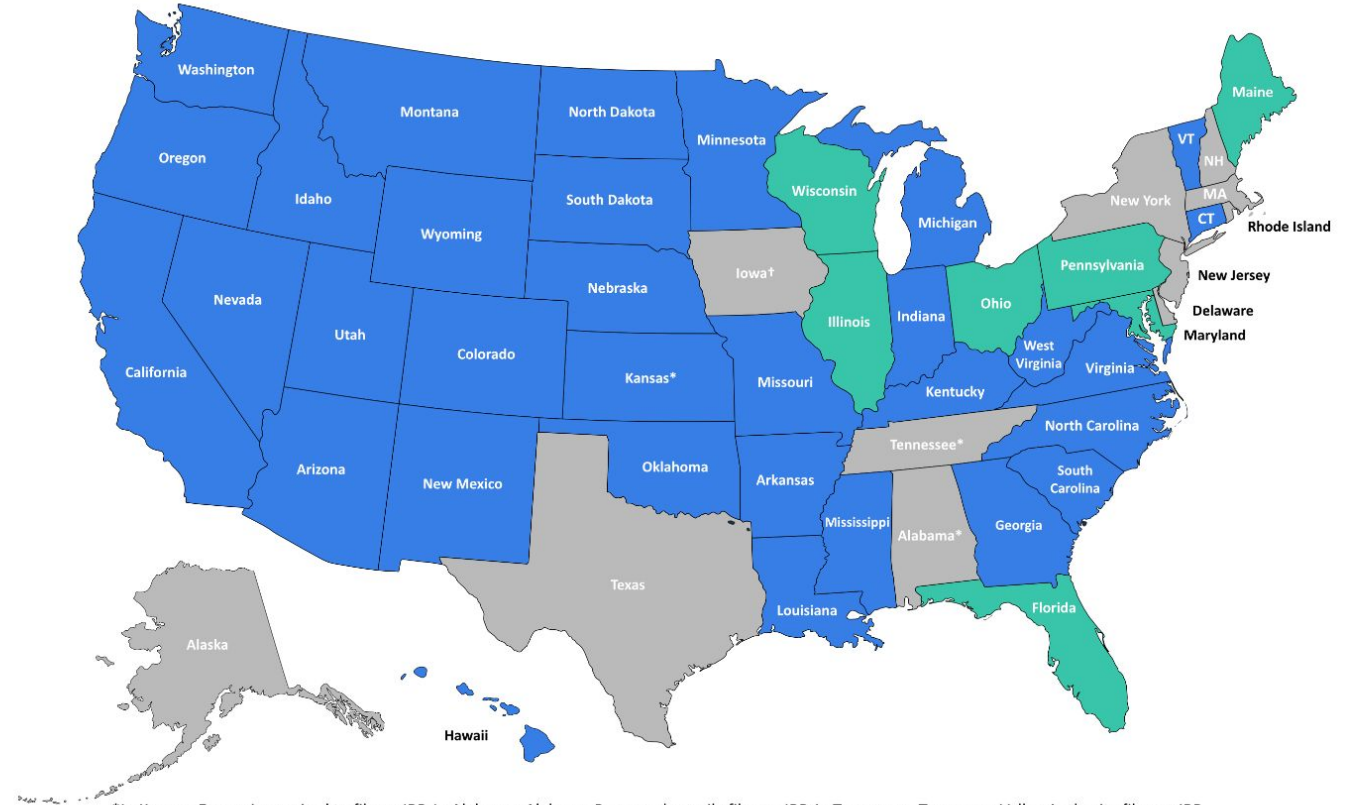
- Reliability requirements
- Regulatory requirements
- Operational constraints
- Market factors



Source here and for next several slides: Biewald et al. (2024), *Best Practices in Integrated Resource Planning: A guide for planners developing the electricity resource mix of the future*

Where are IRPs used?

- Resource plan types in the US
 - Full IRP
 - Long-term resource plan
 - No filing requirement
- Regulatory scrutiny varies
 - Litigated docket
 - Formal acknowledgement
 - No formal approval process



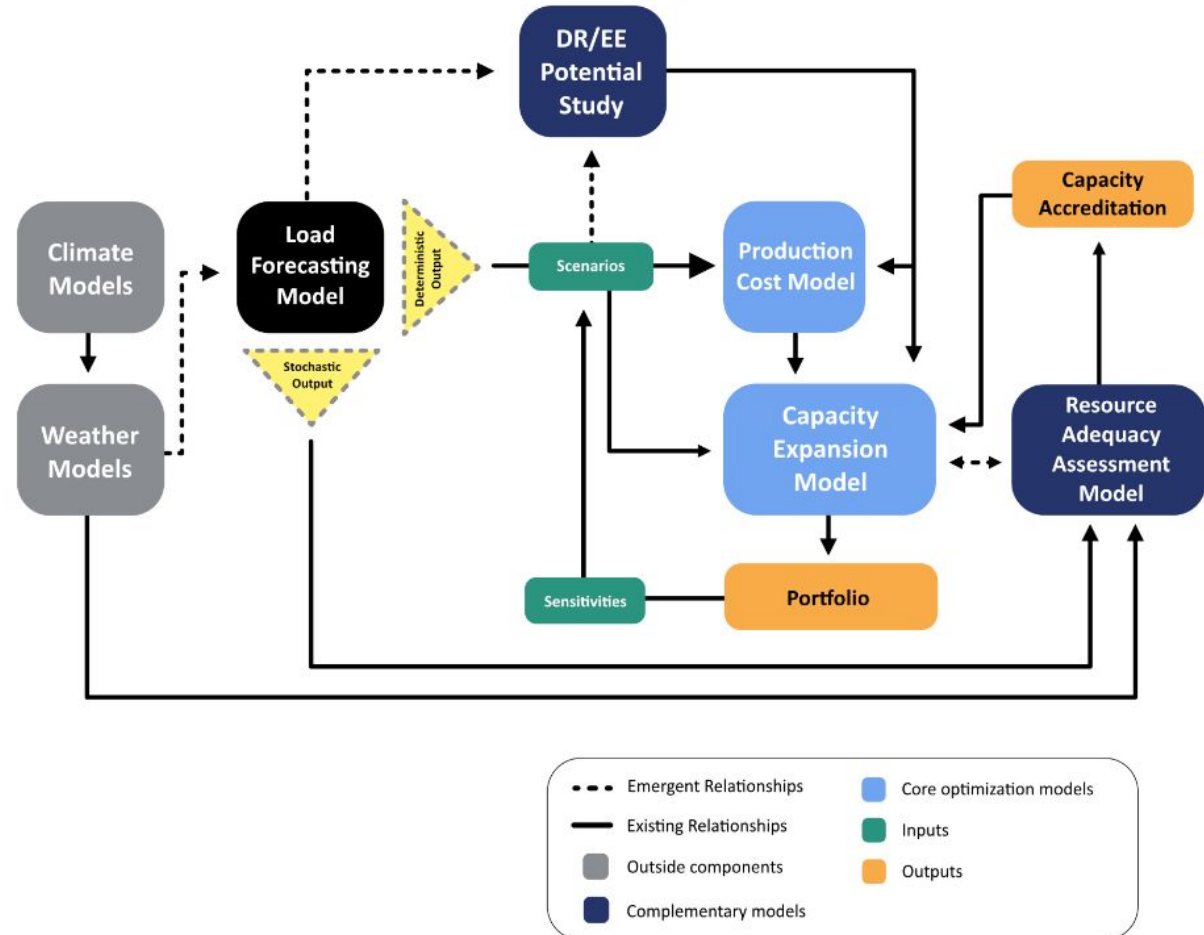
State has an IRP and filing requirement

State does not have a filing requirement for long-term plans

State has a filing requirement for long-term plans

IRP models

- IRP analytics are dominated by different layers of modeling to produce least-cost portfolios
- DERs are involved in several of these models:
 - Load forecasting
 - DR/EE potential study
 - Production cost (under certain assumptions)
 - Capacity expansion
 - Resource assessment (RA) model
 - Capacity accreditation

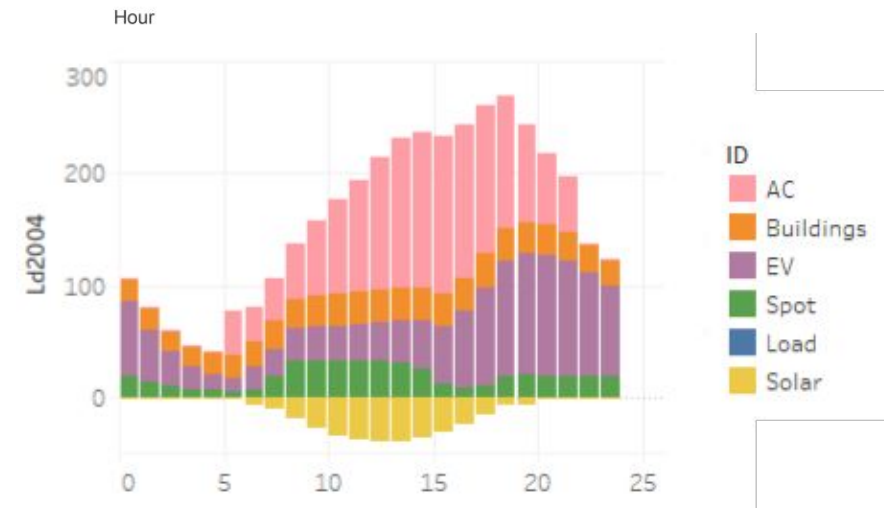
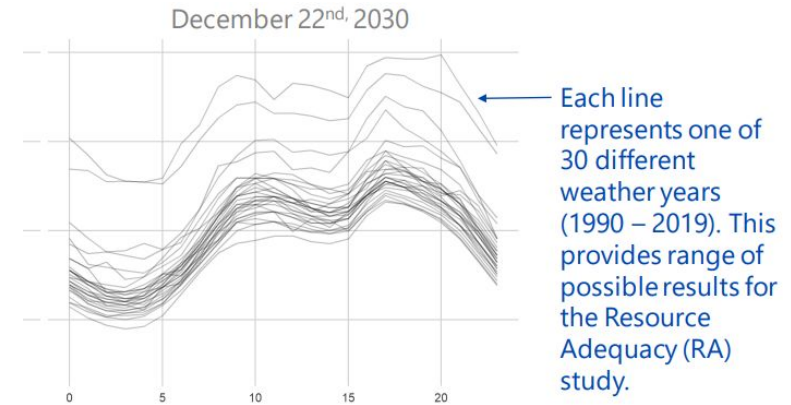


Forecasting DERs



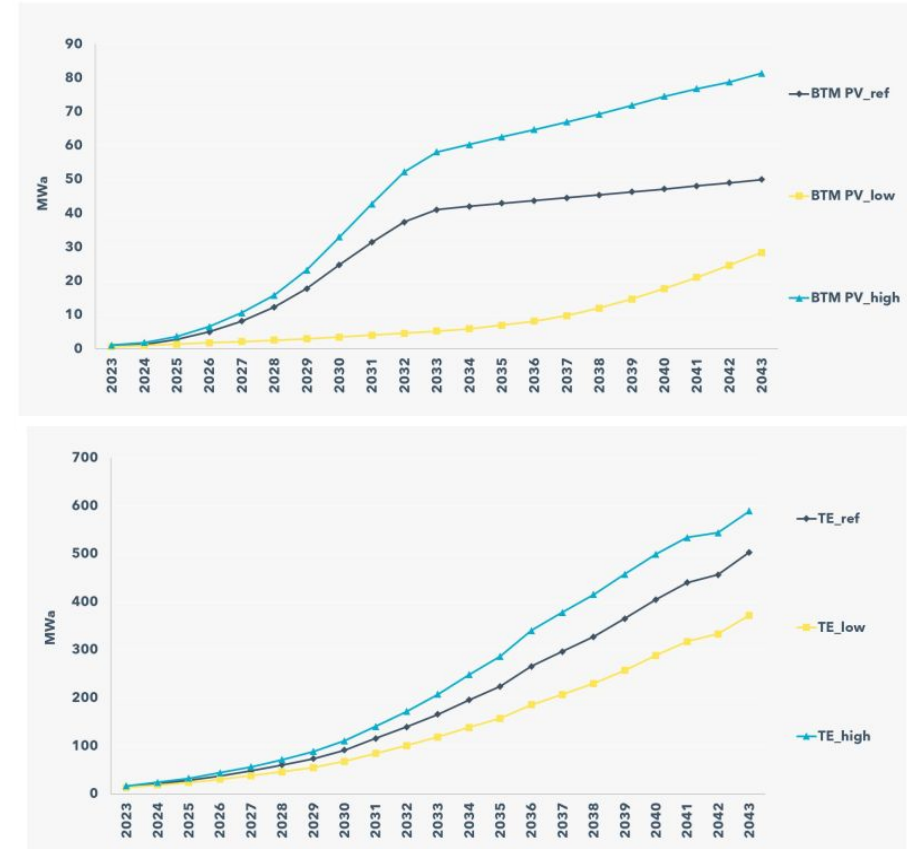
Forecasting leading practice: Granularity and resolution

- Leading practice is to develop hourly load forecast that reflects:
 - Diurnal/nocturnal profiles
 - Seasonal patterns
 - Daily and weekly cumulative energy needs
- Ideally, load forecasts match the spatial unit of analysis of the production cost and/or capacity expansion model
 - Recognize spatial diversity in load growth and characteristics
 - Better represent load in reliability assessment model by capturing idiosyncratic stochastic properties
- Example: [Seattle City Light's 2022 IRP](#)
 - Uses shaping models based on several methods to produce hourly load profiles by end use
 - Applying the model over a wide range of weather years, the shaping process can produce a distribution of hourly loads suitable for an RA analysis



Forecasting leading practice: End use-based models

- End use-based, bottom-up forecasts are the basis of leading practices to forecast loads and grid-edge resources
 - Limited role for econometric or time series approaches, especially with higher uncertainty
- Separately forecast
 - Adoption/Saturation
 - Typical models include propensity of adoption, but depending on context linear trends, S-curve (Bass) models, or multivariate regression *may* still work well
 - Normal operation
 - Depending on the end use, modeling of operational profiles may need to be weather-sensitive and hence correlated
 - Flexible operation
 - This is an emerging aspect
 - Can rely on demand response programs run by the utility or other control- or price-based signals

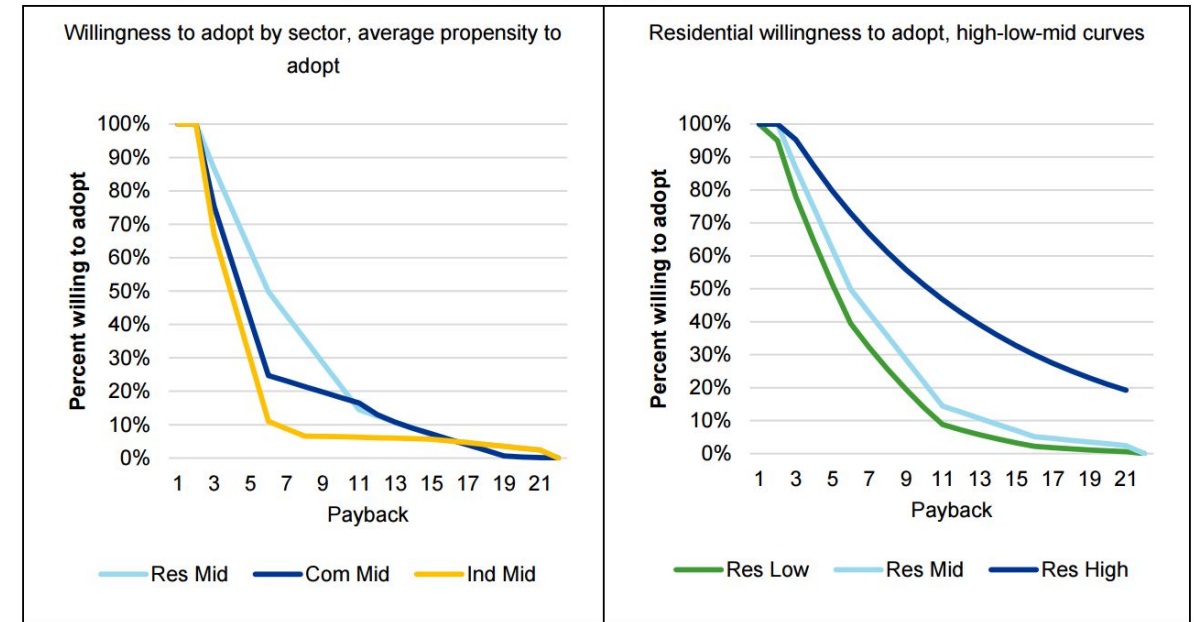


PV (left) and EV (right) forecasts from [PGE's 2023 IRP](#)

Forecasting leading practice: End use-based models – Technology adoption

- Leading practice is to use a Bass model combined with a propensity of adoption model (illustrative graphs at right) — more versatile and flexible than linear growth predictions
- Example: Distributed generation (DG) propensity of adoption model in [PacifiCorp's 2025 IRP](#)
 - Identified differences across service territory and produced three propensity of adoption curves (low, average, high) that apply to different areas
 - Willingness to adopt is represented by share of customers that adopt DG based on payback period
 - This is specific to DG's value proposition, but similar processes based on other drivers can be implemented
 - Calibrate parameters in the Bass model based on historical data and other assumptions

Figure 3-11 Willingness to Adopt Based on Technology Payback



Source: [PacifiCorp's 2025 IRP](#)

Forecasting leading practice: End use-based models – Technology adoption

- NIPSCO (2021 IRP) developed a bottom-up forecast based on:
 - EV growth rate to determine number of vehicles
 - Energy usage per vehicle for energy consumption
 - Charging behavior to determine peak load impacts (see figures)
- Considered three scenarios for four classes of vehicles
 - Light duty vehicles (LDV), medium duty vehicles (MDV), heavy duty vehicles (HDV), and transit, with low, medium and high growth scenarios based on MISO's Transmission Expansion Plan (MTEP) futures scenarios
- Model is comprehensive and assumptions are transparent, but improvements are possible
 - An exponential growth assumption may work in the short term, but distorts long term growth. An S-curve or propensity of adoption approach is better
 - Key drivers of vehicle energy use were based on historical data that may not predict commuting behavior of future drivers as well as efficiency gains in batteries

Figure 3-9: Low EV Penetration Charging Shape

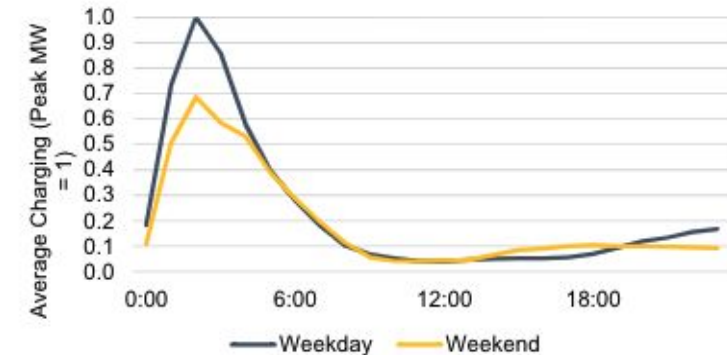
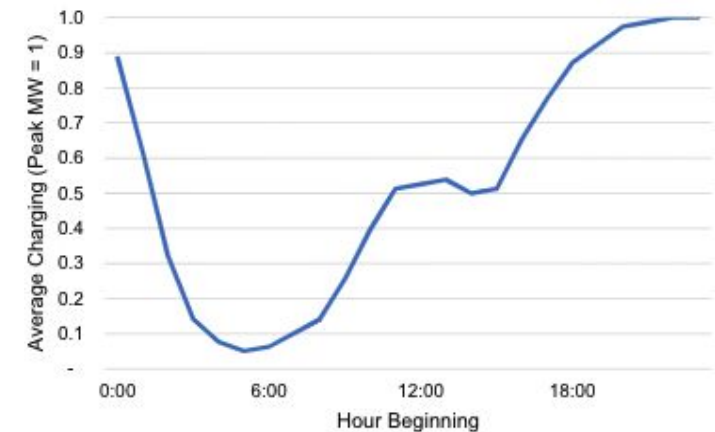


Figure 3-12: MDV/HDV Charging Pattern



Price-based demand response



Motivation

- Loads can be leveraged as a resource for flexibility through **demand response (DR)**
- DR has been assessed and modeled in IRP for decades through market potential studies
- Price-based DR – implemented using time-based rates – could substantially contribute to meeting capacity and other grid needs
- While **IRPs incorporate demand-side resources**, it typically is **not clear**:
 - How the utility characterizes and models **different time-based rates**
 - What **assumptions** the utility uses for price-based DR
 - What are **best practices** in representing price-based DR in IRP



November 2023

The use of price-based demand response as a resource in electricity system planning

Juan Pablo Carvallo and Lisa Schwartz, Lawrence Berkeley National Laboratory

Utilities have conducted IRP for decades to consider both supply- and demand-side resources to meet bulk power system needs. More recently, an increasing number of states are requiring regulated utilities to file plans that identify distribution system needs, including DERs that can avoid or defer certain types of traditional utility investments cost-effectively. Price-based demand response (DR) is an underutilized resource that could substantially contribute to load flexibility. We find that evaluation of price-based DR as a solution to meet identified electricity system needs is uncommon at both planning processes. Where price-based DR is considered as a solution, methodologies are often deficient in the characterization and treatment of this resource. Based on our analysis of utility filings and state requirements, this brief provides recommendations for improving consideration of price-based DR in the context of long-term planning for bulk power and distribution systems.

Introduction

Decarbonizing electricity systems, including electrifying transportation and buildings, will require high levels of flexibility. Loads can be leveraged as flexible solutions at both the bulk power system and distribution system levels. While traditional demand response (DR) programs such as direct load control will continue to play an important role, load flexibility in the future may depend in large part on price-based DR programs, implemented through time-based rates.

Integrated resource planning (IRP) has historically incorporated demand-side resources without a clear connection to (1) the rate structures that underpin them and (2) the potential of underutilized and novel rate structures to drive higher levels of load flexibility. While some utilities began considering DR in *distribution system planning (DSP)* in the 1990s for deferring or avoiding some types of distribution system upgrades — and several jurisdictions now require regulated utilities to consider the locational value of DR and other types of distributed energy resources (DERs) — rate design is not typically considered.

This technical brief focuses on the treatment of price-based DR in IRP, using the framework in Figure 1, and recommends ways to improve consideration of price-based DR as a bulk power system resource. The brief also reviews nascent approaches for including price-based DR in DSP and recommends improvements.



Figure 1. IRP framework for price-based DR analysis.

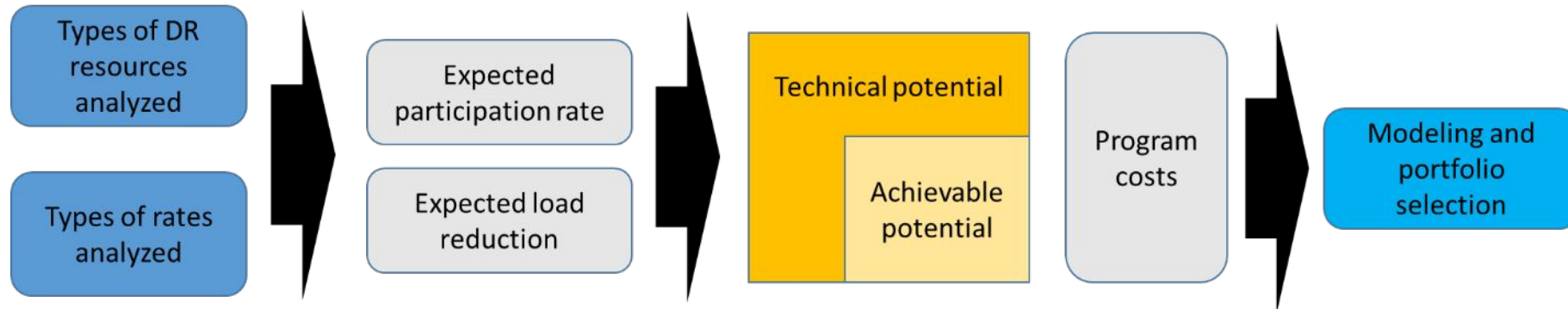
The work described in this report was funded by the U.S. Department of Energy's Office of Electricity under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231. If you have questions, please contact Juan Pablo Carvallo (JCarvallo@lbl.gov) or Lisa Schwartz (LSchwartz@lbl.gov).

See [Carvallo and Schwartz, 2023](#)

Approach

- **Integrated resource planning**

- Examined state requirements for IRPs and 12 recently filed plans by U.S. electric utilities in the West, Midwest, and Southeast
- Analyzed price-based DR in these IRPs using the following framework



- **Distribution system planning**

- Reviewed DR-related provisions in state requirements for regulated utilities to conduct DSP
- Reviewed nascent utility practices for DSP in 6 states: California, Colorado, Hawaii, Minnesota, New York, and Oregon

Time-Varying Rates

- The [U.S. Energy Information Administration](#) defines time-based rate programs (aka time-varying rates) as those "designed to modify patterns of electricity usage, including the timing and level of electricity demand."
- **Time of Use (TOU)** – Customers pay different prices at different times of day
- **Real Time Pricing (RTP)** – Retail electricity price fluctuates hourly or more often to reflect changes in the wholesale price of electricity, on either a day-ahead or hour-ahead basis
- **Variable Peak Pricing (VPP)** – Prices set on a daily basis
- **Critical Peak Pricing (CPP)** – Encourages reduced consumption during periods of high wholesale market prices or system contingencies, using a pre-specified high rate or price for limited number of days or hours
- **Critical Peak Rebate (CPR)** – Same intent, but provides a rebate to the customer on a limited number of days and for a limited number of hours*

*Definitions adapted from Form EIA-861S Annual Electric Power Industry Report



Types of DR

- Utilities characterized programs as **dispatchable or non-dispatchable**
 - Price-based DR is typically considered non-dispatchable
- About **a third of the utilities in the sample deemed price-based DR unsuitable** for IRP
 - Predictability
 - Low volume
- Almost all IRPs studied included **some direct load control (DLC)** or interruptible load programs
 - Most commonly for space conditioning, water heating, and commercial/industrial interruptible loads
 - Less common for smart thermostats and smart appliances
 - About a third of utilities reported EV programs, but it was unclear if they were DLC or price-based

Types of Rates

- Most **common rates**: TOU and CPP
- **Existing vs. new** price-based DR
 - Missed distinction
 - Relevant to consider as a resource
- Two utilities **screened out CPP and RTP** due to advanced metering infrastructure (AMI) limitations
 - Did not consider metering implementation cost as part of the analysis
- Little to no explanation of the **duration and price levels** for blocks/events

	Rate types				
Customer segment	TOU	CPP	VPP	CPR	RTP
Residential	6	4	2	0	0
Commercial	5	4	2	0	2
Industrial	5	2	2	0	3
Irrigation	2	0	0	0	0
Undefined segment	3	0	0	0	0



Expected Participation Rate

- 2/3 of utilities clearly reported participation rates by type and customer segment
- Only one distinguished opt-in vs opt-out really matters!
- Only one considered low/high values for this potentially uncertain variable
- Data sources were not transparent, but lower & higher values were *remarkably* consistent
- Opt-out values were lower than reported in the literature
- Unclear how utilities determined preferences for customers with multiple rate options

Utility ID	Res-TOU	Res-CPP	Res-VPP	C&I-TOU	C&I-CPP	C&I-RTP
1	13% opt-in; 74% opt-out	-	25%	13% opt-in; 74% opt-out	-	-
2	-	15% eligible load	-	10% eligible load	-	-
3	28% opt-in	17% opt-in	-	13% opt-in	18% opt-in	3-5% opt-in
4	-	-	-	-	~10% (ind)	-
5	30% (low); 75% (high)	-	7% (low); 24% (high)	10% (low); 22% (high)	-	5% (low); 10% (high)
6	27%	-	-	14% (comm); 22% (ind)	-	-
7	~70%	-	-	-	-	-
8	36%-64%	-	-	-	23%-50%	-

Expected Load Reduction per Participant

- Reporting reveals the **diversity of variables** that inform load reductions
 - Opt-in vs opt-out, season, DLC or other enabling technologies, other variables
- **Unclear** how load reductions **contribute to peak demand** or other RA objective
 - unexplained derating
- **Scant information on sources for these values**

Utility ID	Res-TOU	Res-CPP	Res-VPP	C&I-TOU	C&I-CPP	C&I-RTP
1	4.6% summer; 1% winter					
2	5.7% (opt-in); 3.4% (opt-out)		10%	3.1% (opt-in); 2.6% (opt-out)	4%	
3		12% no DLC; 40% with DLC			5% no DLC; 7% with DLC	
4	5.7% summer; 2.9% winter	12.5% summer; 7.5% winter		~3% summer; ~1.5% winter	~7% summer; ~4% winter	~7% summer; ~4% winter
5					20%	
6	12%		10%	5%	20%	13%
7	4% (low); 5.3% (high)					
8		9%			11%	

Technical and Achievable Potential

- Participation rates and load reduction per participant are used to estimate **technical potential**
- Apply a qualitative derating to establish an **achievable potential**
- In contrast to other applications (e.g., energy efficiency programs), there is no economic consideration in achievable potential
- We found **wide variation** in normalized potential by rate type across entities

Rate type	Potential range (%)
TOU	Opt-in: 0.25%-3.8% Opt-out: 1%
CPP	0.2%-1%
VPP	0.25%-6.6%
RTP	0.1%



Implementation Costs and Economic Assessment of Rates

- Half of the IRPs reviewed **did not report costs** to implement price-based DR
- AMI costs were not assessed
- Costs are *remarkably similar across utilities* located in different parts of the country
- Unclear if these are **notional costs or based on actual costs**

Utility ID	Subtype*	TOU			VPP/CPP/RTP		
		Fixed - Initial	Fixed - Ongoing	Variable	Fixed - Initial	Fixed - Ongoing	Variable
1	State 1	\$12k	-	\$57.50	\$12k	-	\$175
1	State 2	\$6k	-	\$69			
2	Res				\$150k	\$75k	\$25
2	Com				\$150k	\$75k	\$50
3	-				\$235k		-
4	-	\$150k	\$250k	-	\$150k	\$250k	-
5	-		\$100k	\$5/MW			
6	Res				\$100k	-	\$30
6	Com				\$100k	-	\$30

Levelized Cost of Capacity (LCOC)

- Fixed and variable costs can be **aggregated** and **coupled** with achievable potential to **estimate LCOC**
- LCOC can be **compared against other capacity resources** and cost of new entry (CONE) determined for ISO/RTO (if relevant)
- Capacity costs are **very low** compared to CONE or to other resources in IRP
- LCOC varies substantially across utilities, even for standard rates like residential TOU

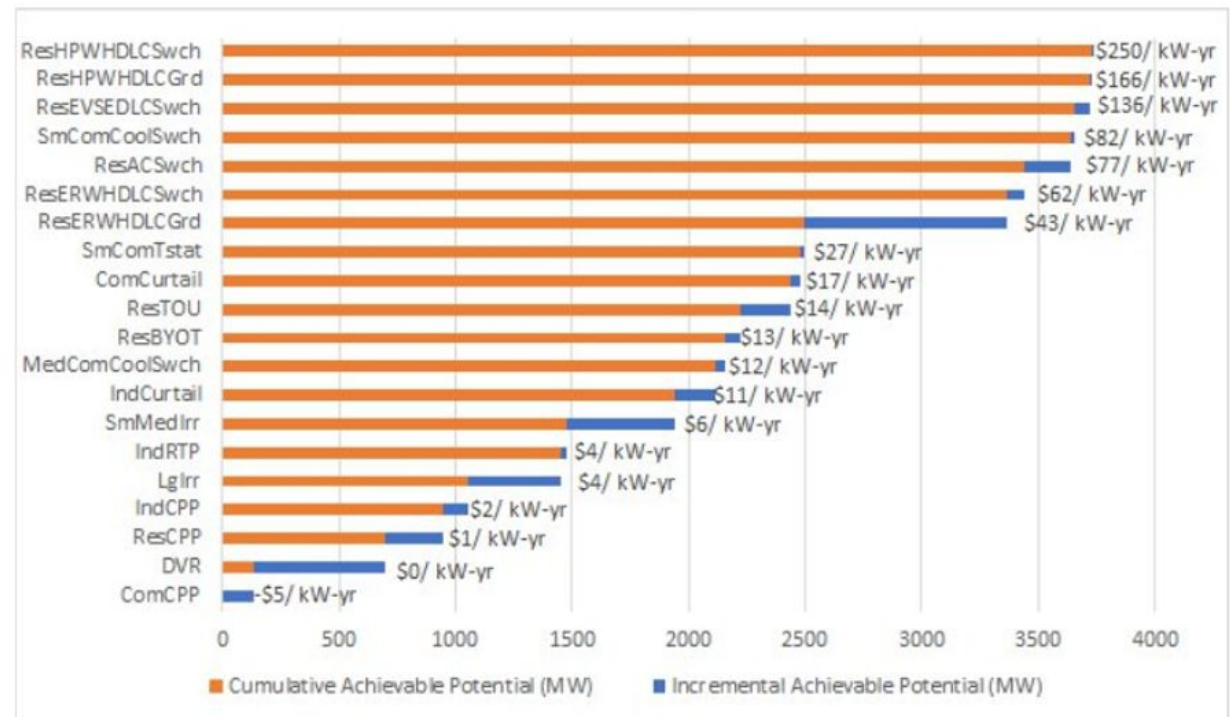
Utility ID	Res-TOU	C&I-TOU	Res-CPP	C&I-CPP	Res-VPP	C&I-RTP
1	\$80-\$100/kW-yr				\$33-\$59/kW-yr	
2			-\$3 to -\$8/kW-yr	\$81-\$86/kW-yr		
3				\$22/kW-yr		
4	\$16/kW-yr				\$10/kW-yr	\$8/kW-yr
5	\$7/kW-yr	\$14 \$18/kW-yr				
6	\$14-\$36/kW-yr	\$6-\$8/kW-yr				
7				\$71/Kw-YR		



Supply Curve Example

- The LCOC can be used to **construct a supply curve** that the capacity expansion model uses to select an optimal portfolio of price-based DR as part of its optimization process
- However, 75% of the IRPs analyzed **did not construct these supply curves** because price-based DR is not treated as a resource

Demand Response Achievable Technical Potential in 2041 with Net Levelized Cost - Summer



Example DR supply curve used with capacity expansion model (Northwest Power and Conservation Council, 2021)

Price-Based DR in IRP: Shortcomings

- The way price-based DR was considered in the portfolio analysis in IRP reports reviewed is **hard to track at best and unclear in general**
- Common **shortcomings** in current IRP practices for preferred portfolio selection related to price-based DR
 - **Lack of transparency** in type of price-based DR modeled
 - **Rationale for level** of price-based DR adopted
 - Treating price-based DR as a **load reduction**
 - **Lack of use of supply curves** or lack of transparency
 - **Low capacity** assigned to price-based DR, and amount selected, are **unsupported**



Price-Based DR in IRP: Leading Practices

- **Treat price-based DR as a resource and not as a load reduction**
- Use **granular cost data for price-based DR**, including customer segments and subsegments, rate types, and load reduction and participation rate bins/categories, among other factors.
- Recognize that **price-based DR might defer transmission capacity**, by internalizing potential avoided costs in the LCOC or through transmission expansion simulations
- Apply any **requirements for acquisition** of price-based DR as **lower bounds** for resource planning.
- Use **scenario and stochastic analysis** for price-based DR, especially as it becomes a larger portion of the utility's incremental portfolio

Further integrating DERs into bulk power system planning

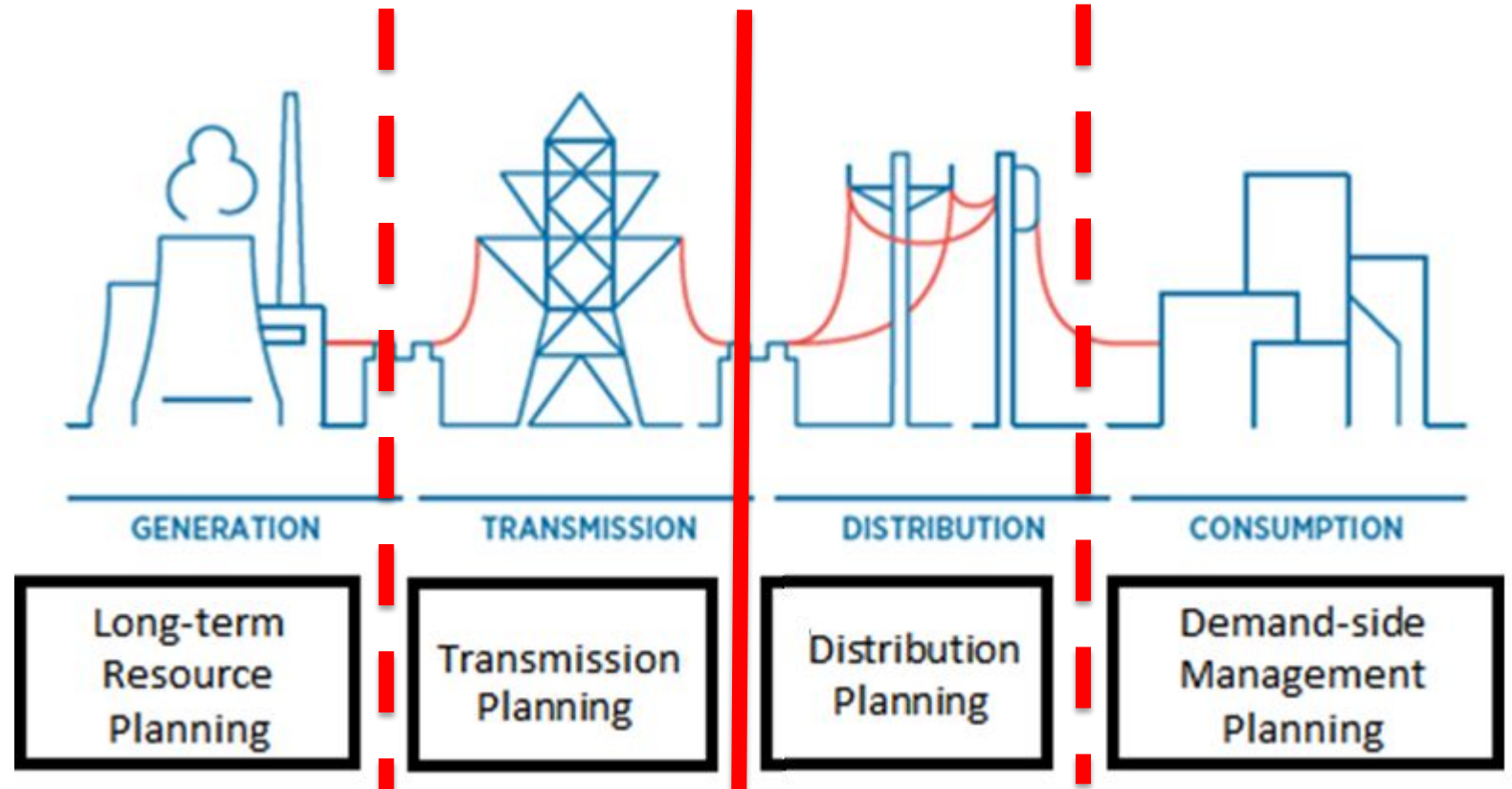


Limitations of IRPs for DER integration

- Leading IRP practices treat DERs as a resource and evaluate them as part of the capacity expansion exercise
- But this method still completely ignores distribution system impacts of DERs, in addition to:
 - Control infrastructure needed to operate DERs
 - Behavioral aspects of customer-sited resources
- Other planning approaches can account for these issues and effectively integrate distribution and bulk power system (BPS —generation + transmission) planning

The fragmented power system planning process

- Power system planners historically have drawn a hard line between BPS and distribution system planning
- Integration between resource, distribution and transmission planning varies by jurisdiction
- Some recent integration between demand-side management and distribution planning (e.g., non-wires alternatives and hosting capacity analysis)

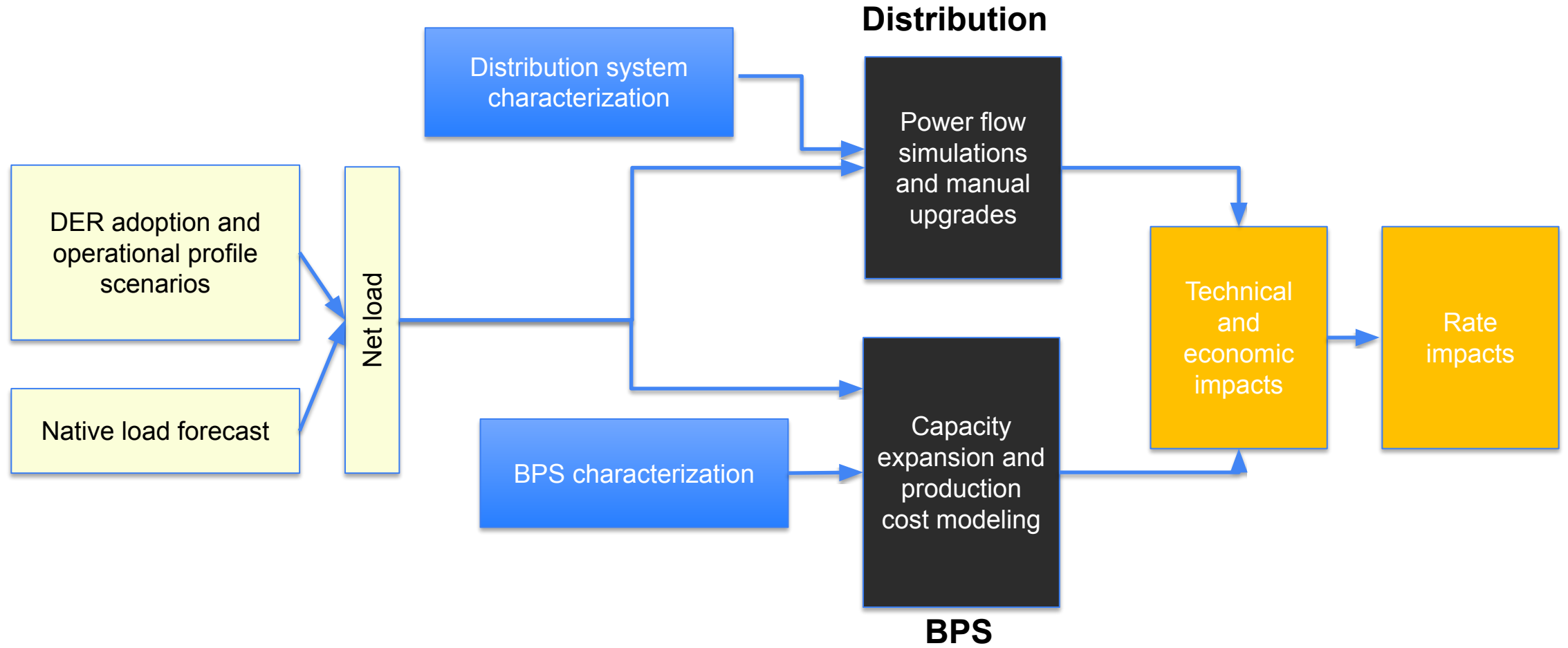


From domain-level to integrative analysis

- Regulators and regional system planners want to understand the impacts of DERs across domains in the power system: distribution and BPS.
- DER impact assessments are usually constrained to one domain (distribution or BPS) based on analyses developed in planning processes—distribution planning, IRP, and benefit-cost analysis.
- Integrative modeling approaches can address these limitations.
 - **Sequential Integrative Modeling (SIM)**
 - A staged decision-making framework where each domain is simulated from the customer side aggregating up to the supply side, using industry-standard tools to determine investment and operational decisions for each domain
 - **Comprehensive Integrative Modeling (CIM)**
 - A single optimal decision-making framework that can encompass generation, transmission, distribution, and DER domains and produce holistic investment and operation decisions.

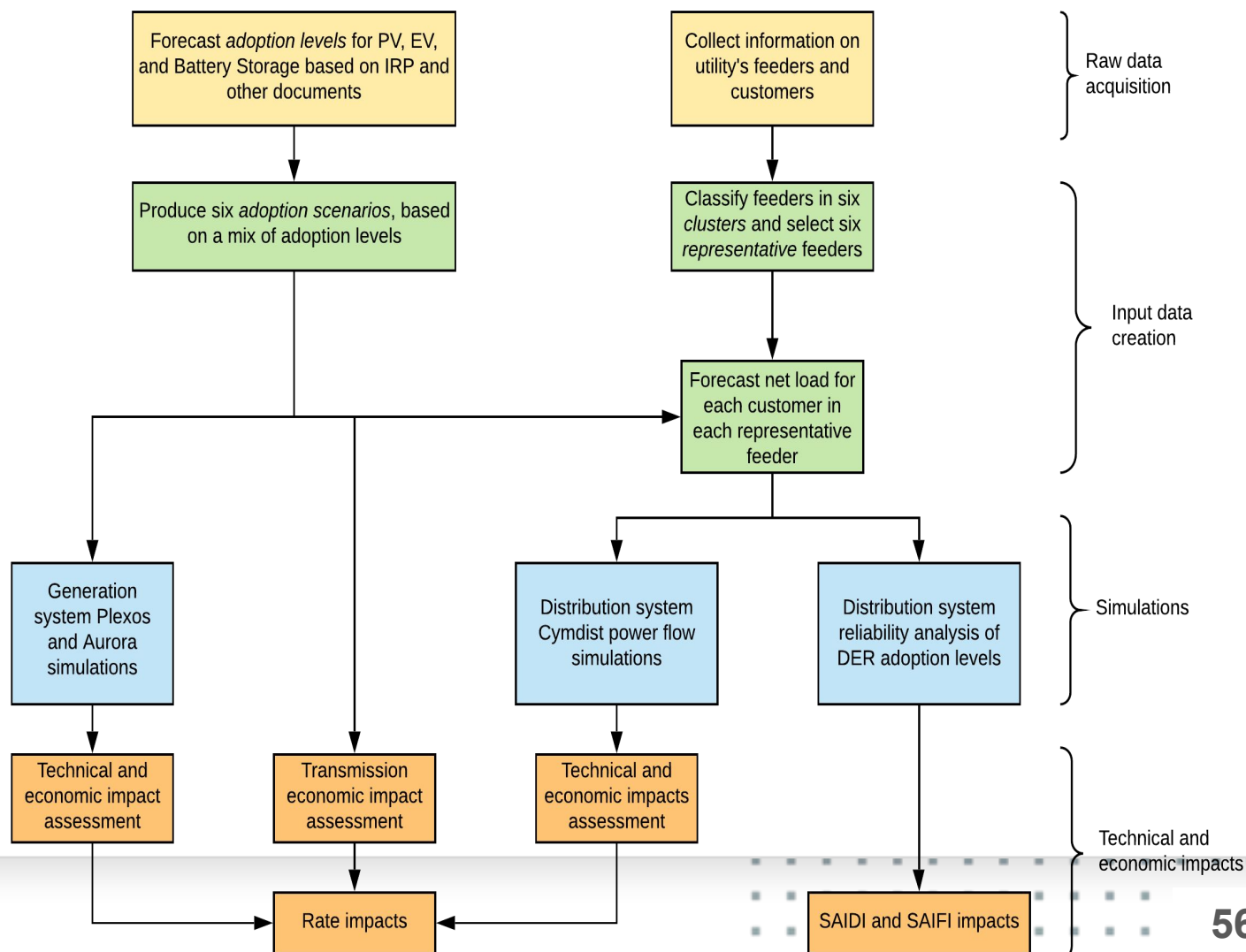


SIM framework overview



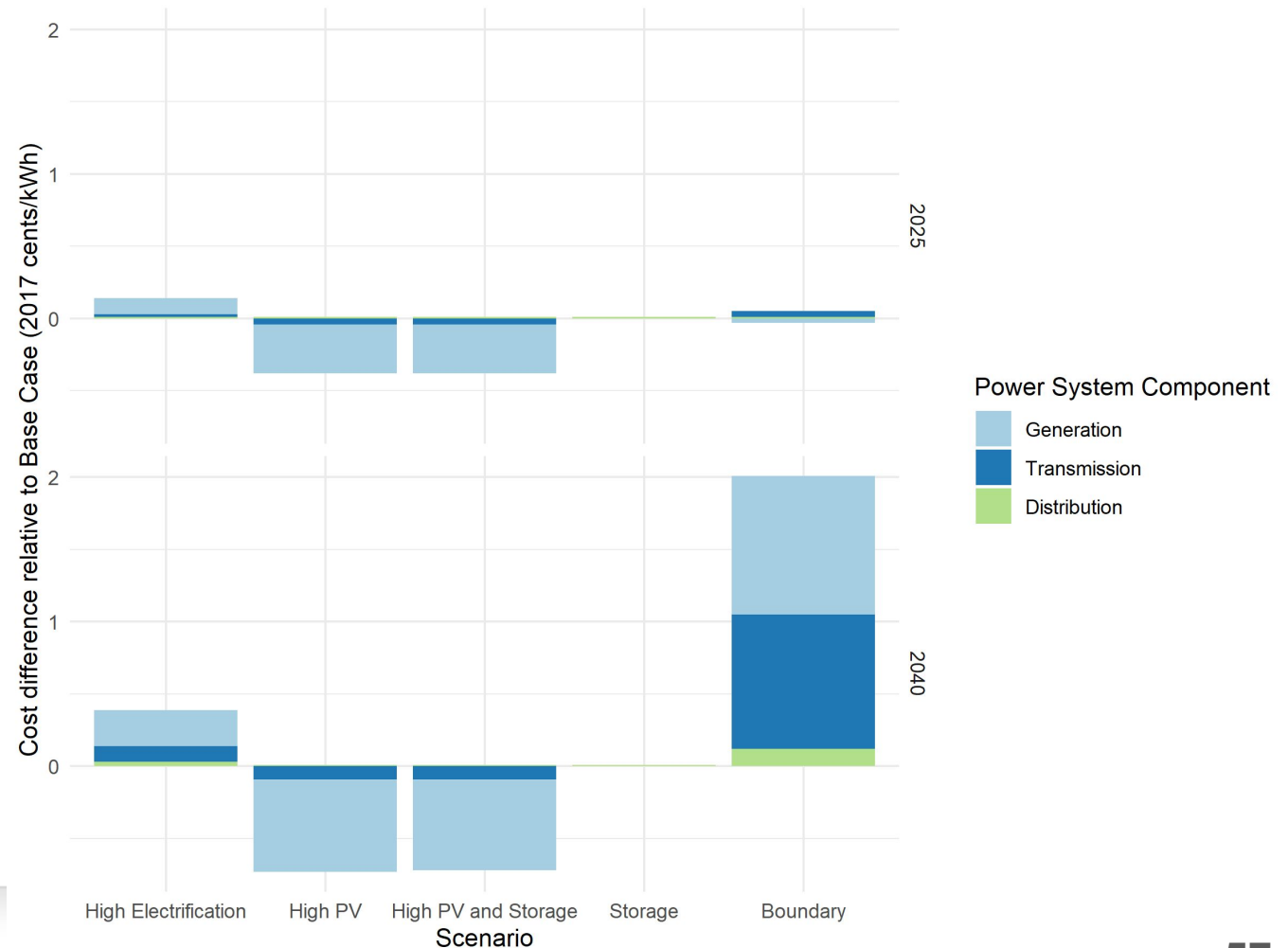
SIM example: Indiana 21st Century Energy Policy

- Define DER adoption *levels*
- Collect adoption levels in different *scenarios*
- Produce hourly profiles for each DER type, in addition to net load
- Distribution
 - Locate DERs in each representative distribution feeder load node
 - Cymdist power flow simulations and upgrades
- BPS
 - Aggregate and scale distribution level load, add industrial load
 - Capacity expansion with Plexos
- Translate cost impacts into rates

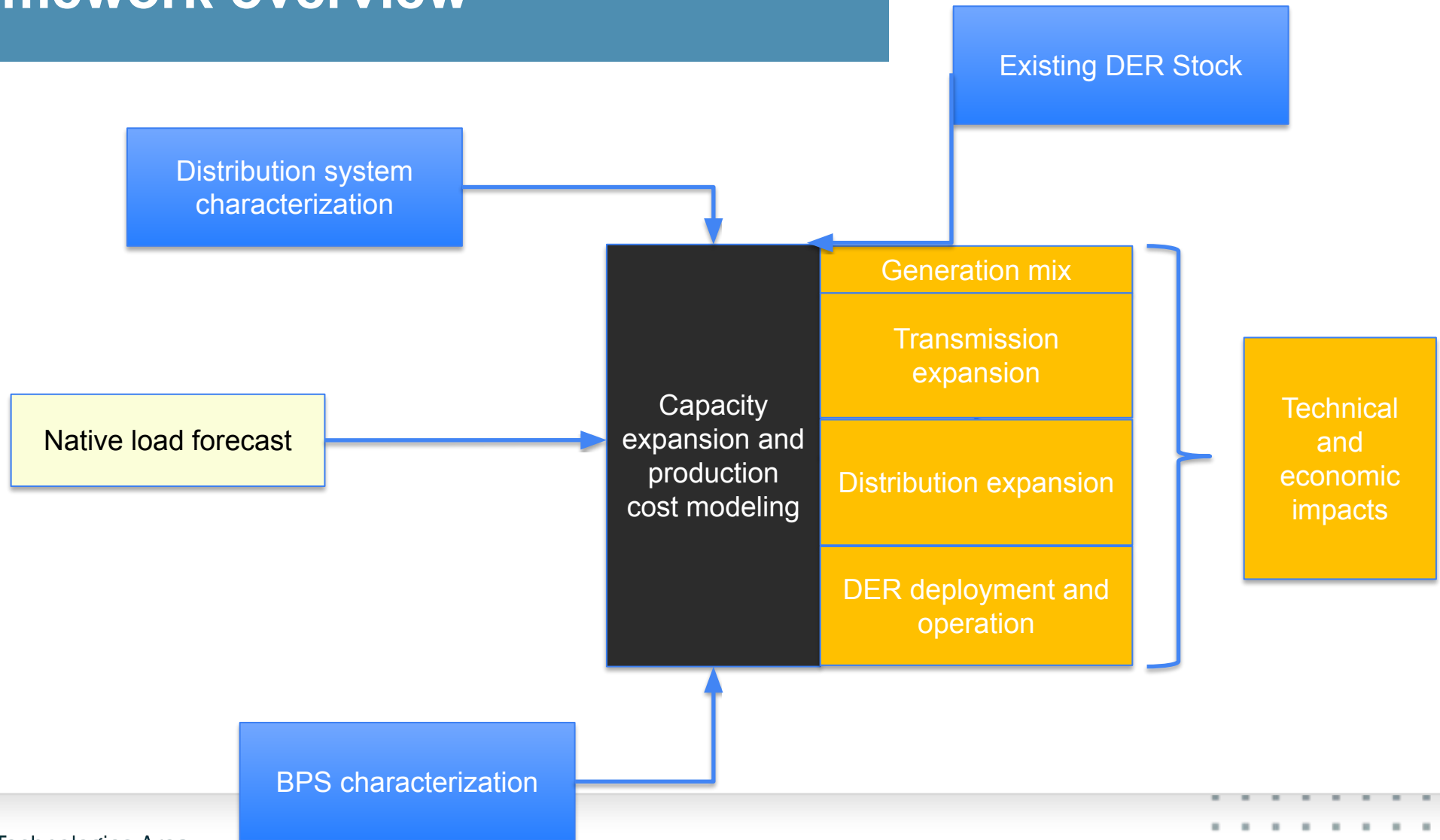


SIM-Indiana: Domain-level cost impacts

- ▶ SIM allows capturing cost impacts across all domains for internally consistent scenarios
- ▶ In this example
 - Scenarios with high PV penetration have lower costs, mostly from generation capacity
 - However, high EV penetration drives up BPS costs
 - Distribution impacts are moderate compared to transmission and generation



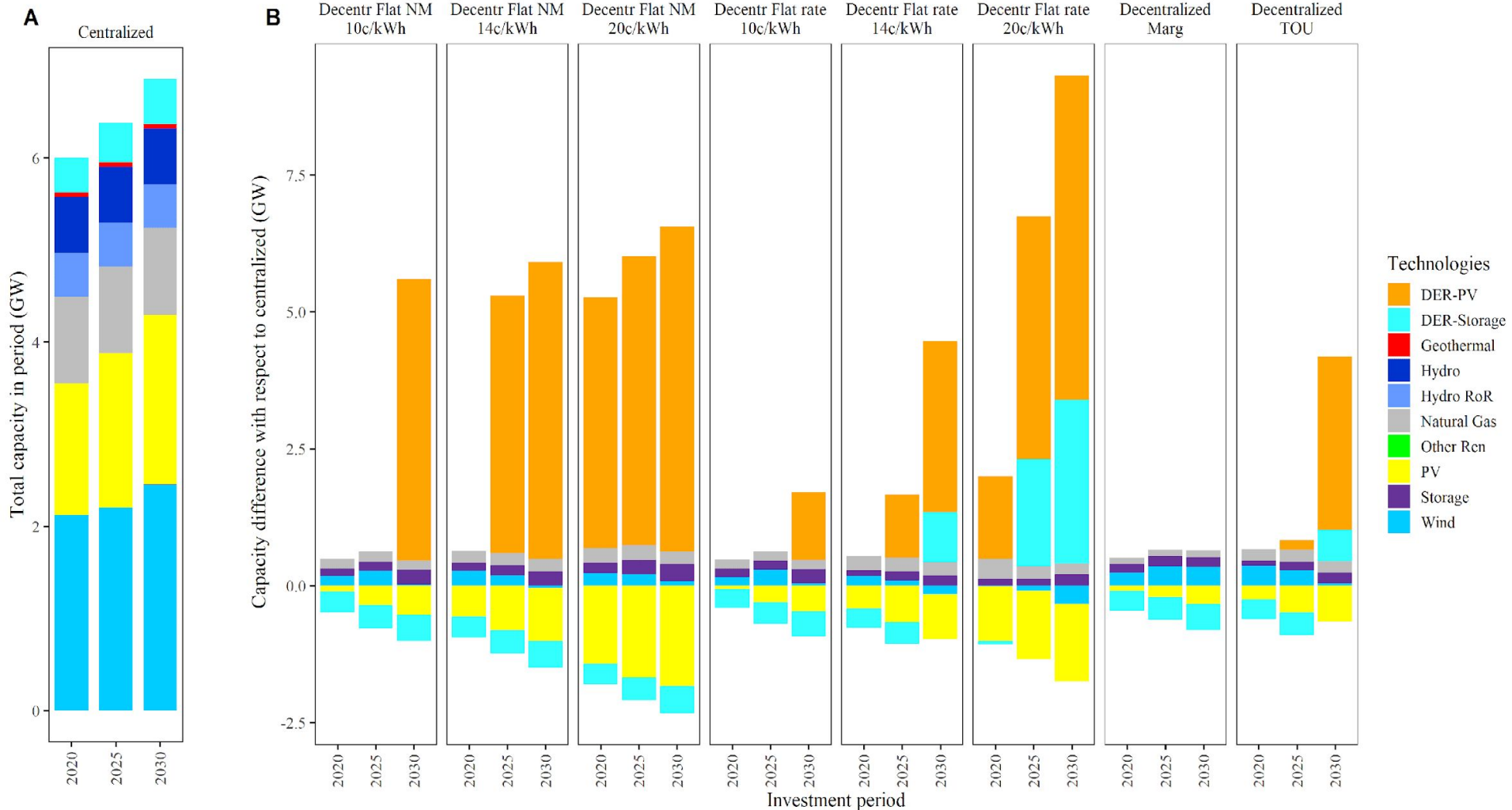
CIM framework overview



CIM example: Grid Access and Planning (GAP) model

- The GAP model uses the same idea as the SIM Indiana model to represent the distribution system using a representative sample of feeders whose results are scaled to the BPS level for integration analysis.
- In contrast to the SIM Indiana model, the GAP model is a single capacity expansion and production cost model that jointly optimizes:
 - Investment in supply side resources (many options include (V)RE, fossil fuels, and storage)
 - Variable costs of supply side resources
 - Investment in transmission lines and substations
 - Investment in primary distribution lines and transformers (not secondary distribution systems)
 - Investment in DERs (PV, storage, and diesel)
- The GAP model can be operated in a decentralized decision-making mode to separate:
 - Customer decisions in DER investment and operation to minimize bills and reduce impacts of energy use
 - Utility decisions to minimize costs and investments to operate the system in response to customer decisions

CIM: GAP model example results on capacity expansion



Example of current implementation

- Several jurisdictions are testing or applying integrated system planning approaches that connect multiple planning processes (e.g., PGE, Xcel MN, Duke)
- Example: [Duke Energy's Integrated System and Operations Planning](#)
 - A “planning framework that optimizes capacity and energy resource investments across generation, transmission, customer delivery (distribution) and customer solutions”
 - The utility develops a bottom-up, hourly forecast at the circuit level using its internal Morecast tool for distribution system planning (DSP)
 - Assumptions and potentially outcomes are shared from Morecast (DSP) for IRP and transmission planning

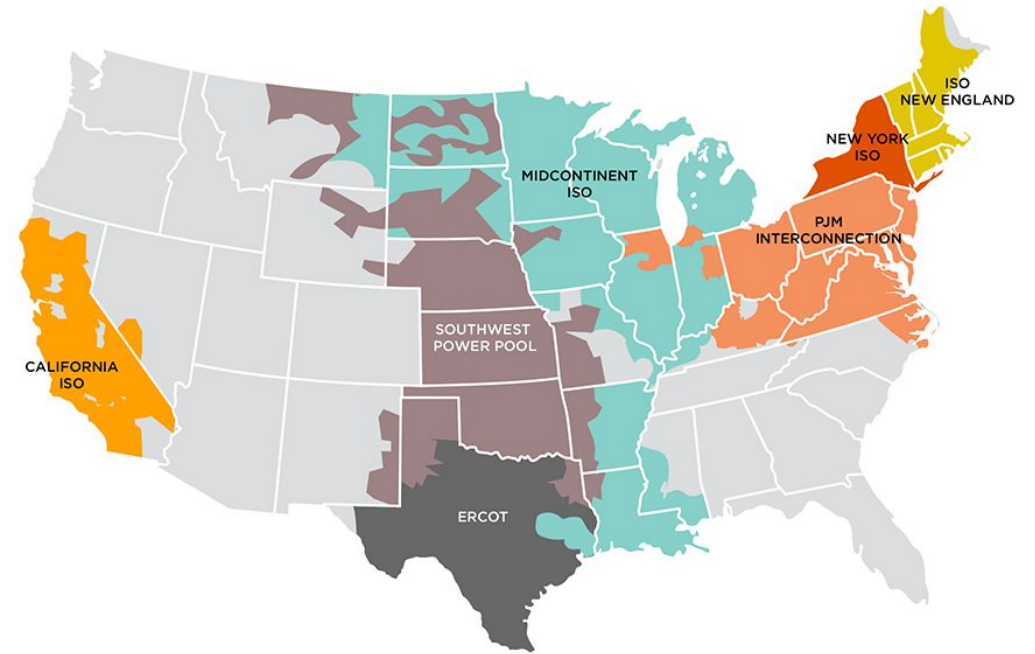


DERs in Wholesale Markets



Wholesale markets vs. IRP

- Wholesale markets are a **different paradigm** compared to IRP
- **Investment decisions** in markets are made mostly by decentralized actors following capacity market signals or load serving entities' needs
- **Operations are technically similar**, but in wholesale markets there are well-defined products that define the **volume and economics** of different operational needs (e.g., operation reserves, ramping, frequency control)



Current state of participation of DERs in wholesale markets

- DERs participating in wholesale markets are primarily **demand response aggregations** (participating as load)
 - States that previously opted out of third-party aggregations providing wholesale market services **have begun to explore relaxing restrictions** (e.g., MI, MO, WI)
 - Majority of participating customers are **large commercial or industrial flexible loads** as opposed to smaller DERs
 - DR participation model **does not leverage full capabilities** of all DERs
 - Challenges may persist related to data sharing, metering and telemetry, operational coordination and communication, avoiding double counting, and more

MARKET
Model and Rate-of-Change
for the Energy Transition

State regulatory opportunities to advance distributed energy resource aggregations in wholesale markets

January 2025

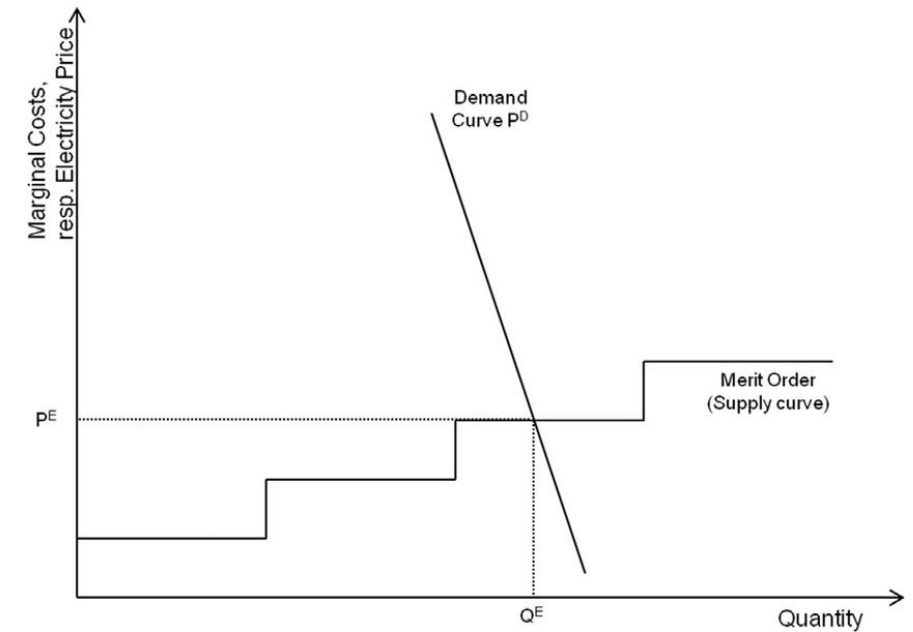
Sydney P Forrester (Berkeley Lab)
Ryan Hledik (Brattle)
Adam Bigelow (Brattle)
Natalie Mims Frick (Berkeley Lab)
Kala Viswanathan (Brattle)

NREL Argonne SENGEL LAB

Available [here](#)

Examples of DERs as supply side resources

- Limited examples of DERs participating as supply side resources
- 291 MW of backup generation approved to inject power in PJM capacity market in 2023
- 20 MW from 5,000 small distributed batteries were bid into ISO-NE's capacity market and delivered 1.8 GWh during 2022 summer peak
- 14.5 MW of energy services and 8.6 MW of ancillary services were deployed from aggregated DERs (mostly batteries) in ERCOT



FERC Order 2222

- **Integration of DERs**
 - Allows aggregations of DERs to participate in wholesale electricity markets operated by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs)
- **Market access for aggregators**
 - Requires RTOs/ISOs to establish rules enabling DER aggregators to register and sell services (capacity, energy, ancillary services) in wholesale markets, even if individual DERs are too small to qualify on their own
- **Coordination**
 - Mandates coordination between RTOs/ISOs, aggregators, and distribution utilities to ensure reliability, avoid double counting, and address operational impacts on local distribution systems
- **Removal of barriers**
 - Prohibits market rules that unnecessarily restrict DER participation and encourages innovation, competition, and grid flexibility to support the clean energy transition

Progress towards implementation

	CAISO		NYISO		PJM		ISO-NE		MISO	SPP
	Filing 1 Jun-22	Filing 2 May-23	Filing 1 Jun-22	Filing 2 Apr-23	Filing 1 Mar-23	Filing 4 Jul-24	Filing 1 Mar-23	Filing 3 Nov-23	Filing 1 Oct-23	Filing 1 Mar-24
Small Utility Opt-In	○	○	○	○	○	○	○			○
Interconnection†			○	○			○		○	
Definitions of DER and DER Aggregator			○							
Participation Model*	●	●	●	○	○	○	●	●	○	●
Types of Technologies	○		○		○	○	○			○
Allow a DER to Serve as its Own Aggregator										
Double Counting of Services	●	●	○		●	○			○	●
Min and Max Size of Aggregation	○	○								
Min and Max Size for DER in an Aggregation	○									○
Distribution Factors and Bidding Parameters	○				○	○			○	○
Locational Requirements*			○		●	●			●	●
Information and Data Requirements†			○		○	○	○	○		
Metering and Telemetry System Requirements	●	●	●	●	●	○	●	●	○	●
Role of Distribution Company	●	●	●	●	○	○			●	●
Ongoing Operational Coordination	●	●	●	●	○	○	○	○	○	●
Role of Relevant Electric Retail Regulatory Authority†	○		○		○	○			○	○
Modifications to List of Resources in Aggregation			○		○	○	○			
Market Participation Agreements†			○	○						

○ = Minor discussion among stakeholders on this issue in this filing

● = Major discussion among stakeholders on this issue in this filing

□ = Issue resolved during current filing or already resolved

■ = Not yet in compliance

* Indicates an issue that has proven challenging for RTO/ISOs to resolve but does not have a material role for retail regulators

† Indicates an issue with a material role for retail regulators but which has not proven challenging for RTO/ISOs to resolve

RTO/ISO Compliance and Implementation Challenges

Double Counting

Requires RTO/ISOs to limit the participation of resources in wholesale markets if a DER aggregation is receiving compensation for the same services as part of another program.

Key Issues: Services provided from DER aggregations, overruling default restrictions

Role of the Distribution Company

Requires a distribution utility review process that takes place during the registration of a DER for participation in wholesale markets.

Key Issues: Registration

Ongoing Coordination

Requires each RTO/ISO to: (1) establish a process for data coordination, (2) include protocols to override RTO/ISO dispatch, and (3) apply a performance penalty to a DER aggregator

Key Issues: Override requirements

Metering & Telemetry

Requires rules that determine how DER aggregations have their energy injection and withdrawal measured, and “telemetry” refers to how aggregations report real-time data (e.g., voltage and frequency) needed to provide fast-response services such as frequency regulation.

Key Issues: Telemetry requirements



Contacts

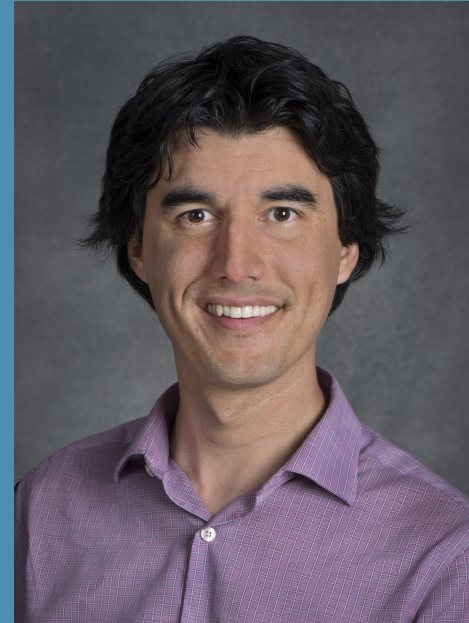
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