Price-Based Demand Response as a Resource in Electricity System Planning

Juan Pablo Carvallo and Lisa Schwartz

February 22, 2024, public webinar

This work was funded by the U.S. Department of Energy, Office of Electricity, under Contract No. DE-AC02-05CH11231.

Agenda

- Study motivation and approach
- Price-based DR in integrated resource planning
  - Findings
  - Recommendations
- Price-based DR in distribution system planning
  - Current practices
  - Recommendations
- Q&A

Technical brief: *The use of price-based demand response as a resource in electricity system planning*

Additional research on resource and distribution planning: https://emp.lbl.gov/bulk-power-system-planning-procurement-market-processes

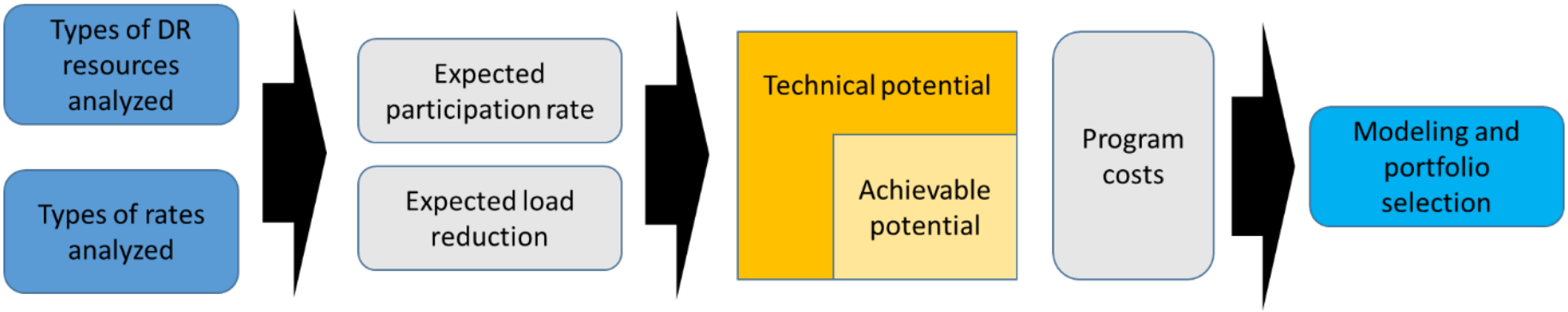
Study Motivation and Approach

Study Motivation

- Electricity system decarbonization and electrification of transportation and buildings will require **high levels of power system flexibility**.
- Loads can be leveraged as a resource for flexibility through **demand response (DR) programs**
- Price-based DR – implemented using time-based rates – could substantially contribute to meeting capacity and other grid needs
- **Integrated resource planning (IRP) incorporates demand-side resources**, but it is **not clear**:
  - How utilities characterize and model **different time-based rates** in IRP
  - What **assumptions** utilities use for price-based DR and **how these assumptions vary** across utilities
  - What are **best practices** in representing price-based DR in IRP
- Price-based DR is **typically *not* addressed in distribution system planning (DSP)** filings.
  - Many utilities may lack sufficient experience with time-based rates to be willing to count on it to reduce peak demand for distribution systems.

Study 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

IRPs Examined

Entity	State(s) covered	Plan year	Supplementary information
AES Indiana	IN	2022	DSM market potential study
Arizona Public Service	AZ	2021	DSM opportunity study
Avista	WA, ID, OR	2021	DR potential assessment
Consumer's Energy	MI	2021	DR potential study
DTE	MI	2019	DR potential study
Entergy Louisiana	LA	2019	DR study
Georgia Power	GA	2022	Load and energy forecast appendix
Northwest Power and Conservation Council	ID, MT, OR, WA	2021	DR appendix
PacifiCorp	UT, OR, WA, ID, CA, WY	2021	DSM conservation potential assessment
Puget Sound Energy	WA	2021	DR potential assessment
Sacramento Municipal Utility District	CA	2019	None
Public Service Company of Colorado (Xcel Energy)	CO	2021	2021-2022 DSM plan

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

Price-Based DR in Integrated Resource Planning: Findings and Recommendations

Types of DR

- Utilities characterize 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 IRP studied include **some direct load control (DLC)** or interruptible load program
  - Most common are space conditioning, water heating, commercial/industrial interruptible loads
  - Less common are smart thermostat and smart appliances
  - About a third of utilities report EV programs, but unclear if they are DLC or price-based

Types of Rates

- Most **common rates** are TOU and CPP
- **Existing vs new** price-based DR
  - Missed distinction
  - Relevant to consider as a resource
- Two utilities **screen out CPP and RTP** due to advanced metering limitations
  - Do not consider implementation cost as part of the analysis
- Little to no explanation of the **choice of 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 report 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 not transparent**, but *remarkable* consistency for lower & higher values
- **Opt-out values lower than literature**
- Unclear how utilities **determine 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
- **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 the achievable potential
- We find **wide variation** in normalized potential by rate type cross 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 IRPs reviewed **do not report the costs** to implement price-based DR
- AMI costs are never assessed
- Costs are *remarkably* **similar across utilities** located in very different parts of the country
- Unclear if these are **notional costs or based on actual costs**

		TOU			VPP/CPP/RTP		
Utility ID	Subtype*	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 Res-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 (CEM) can use to select an optimal portfolio of price-based DR as part of its optimization process
- However, 75% of the IRPs analyzed **do not construct these supply curves because price-based DR is not treated as a resource**

Example of DR supply curve for use with CEM (Northwest Power and Conservation Council, 2021)

Treatment of Price-Based DR as a Resource in IRP: Shortcomings

- The way price-based DR is 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, is **unsupported**

Treatment of Price-Based DR as a Resource in IRP: Best Practices

- Price-based DR should be **treated as a resource** and **not as a load reduction**
- **Cost of price-based DR** should reflect **granularity** in customer segments and subsegments, time-varying rate types, load reduction and participation rate bins/categories, among other factors.
- Utilities should recognize that **price-based DR might defer transmission capacity**, either internalizing this in the LCOC or via transmission expansion simulations
- Utility regulators should make clear that any **mandates** for acquisition of price-based DR are **lower bounds for resource planning**.
- Utilities should use **scenario and stochastic analysis** for price-based DR, especially as it becomes a larger portion of their incremental portfolio

Recs for IRP improvement – DR and rate types

- Types of DR
  - **Do not screen out** price-based DR due to "unpredictability"; demonstrate predictability with rigorous analysis

- Types of rates
  - Study impacts of **enabling technologies** to increase price-based DR potential
  - Support the load reduction potential with a **thorough characterization of the rates' price differential and timing assumptions**

Figure: Institute for Electric Innovation

Recs for IRP improvement – Particip/Load reduction rates

- Participation rate
  - Estimate and assess participation rates for **opt-in and opt-out** versions of price-based DR
  - Distinguish **short-term vs long-term participation rates**, with the latter not limited by acquisition efforts

- Load reduction rates
  - **Transparently** and **rigorously** report empirical data or models used to inform **load reduction rates**
  - Make load reduction rates **consistent with capacity credit** for price-based DR. Ideally, **estimate the effective load carrying capability** (ELCC) of price-based DR to make it comparable to any other IRP resource

Recs for IRP improvement – Potential

- Technical/achievable potential calculations
  - Calculate potential by **season, customer segment, rate type, and opt-in/opt-out** mechanisms
  - Report potential on a **yearly basis throughout the study horizon**, especially given that the capacity contribution of a price-based DR solution may decrease with enrollment
  - Refrain from **screening any DR using cost-effectiveness tests** → treat as resource!
  - Clearly distinguish **standalone and integrated** potential → define price-based DR adoption portfolios
  - Report **assumptions and methods** to estimate **achievable potential from technical**

Price-Based DR in Distribution System Planning: Findings and Recommendations

~20 states require regulated utilities to file some type of distribution plan. Treatment of DERs, including price-based DR, varies.

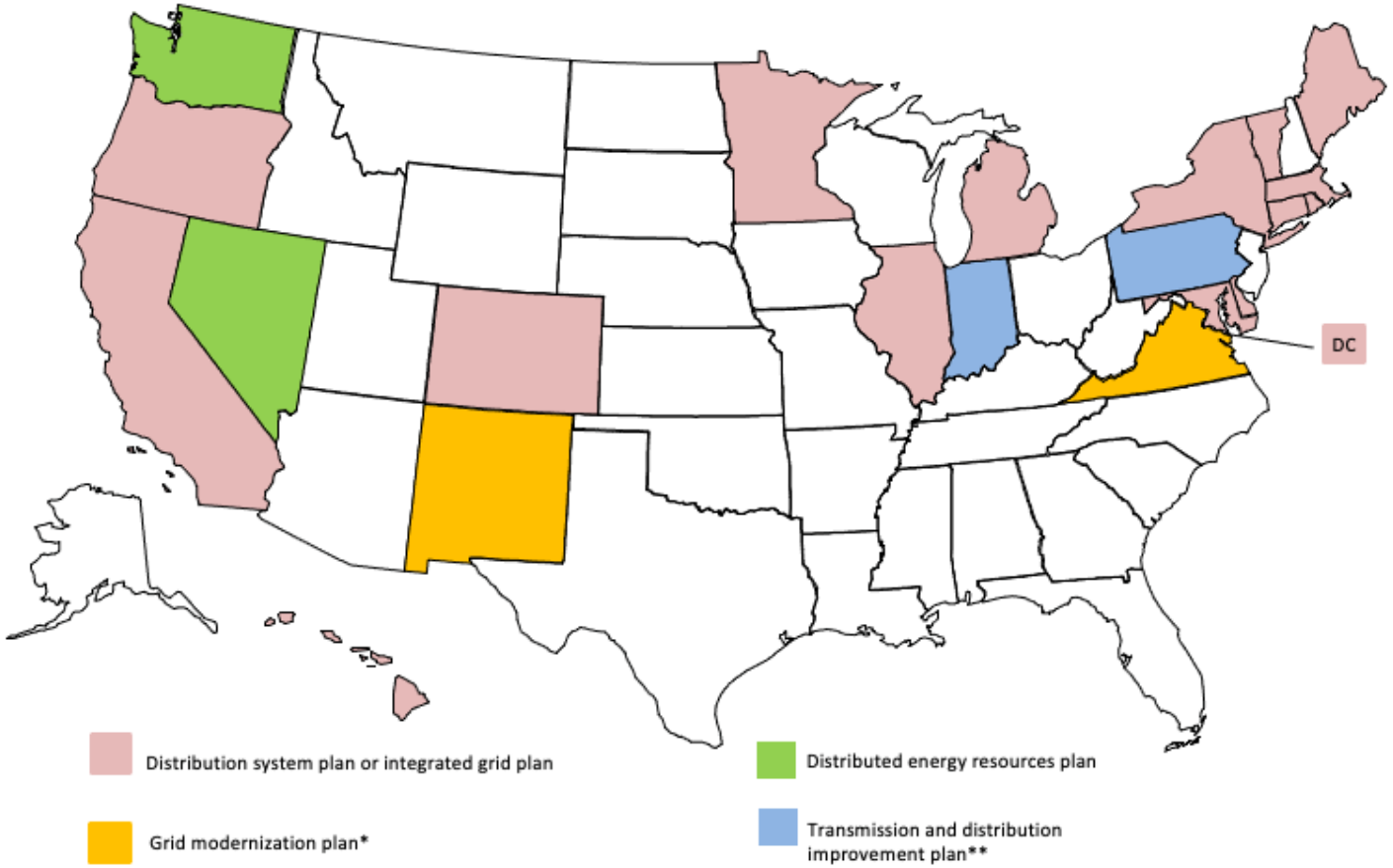
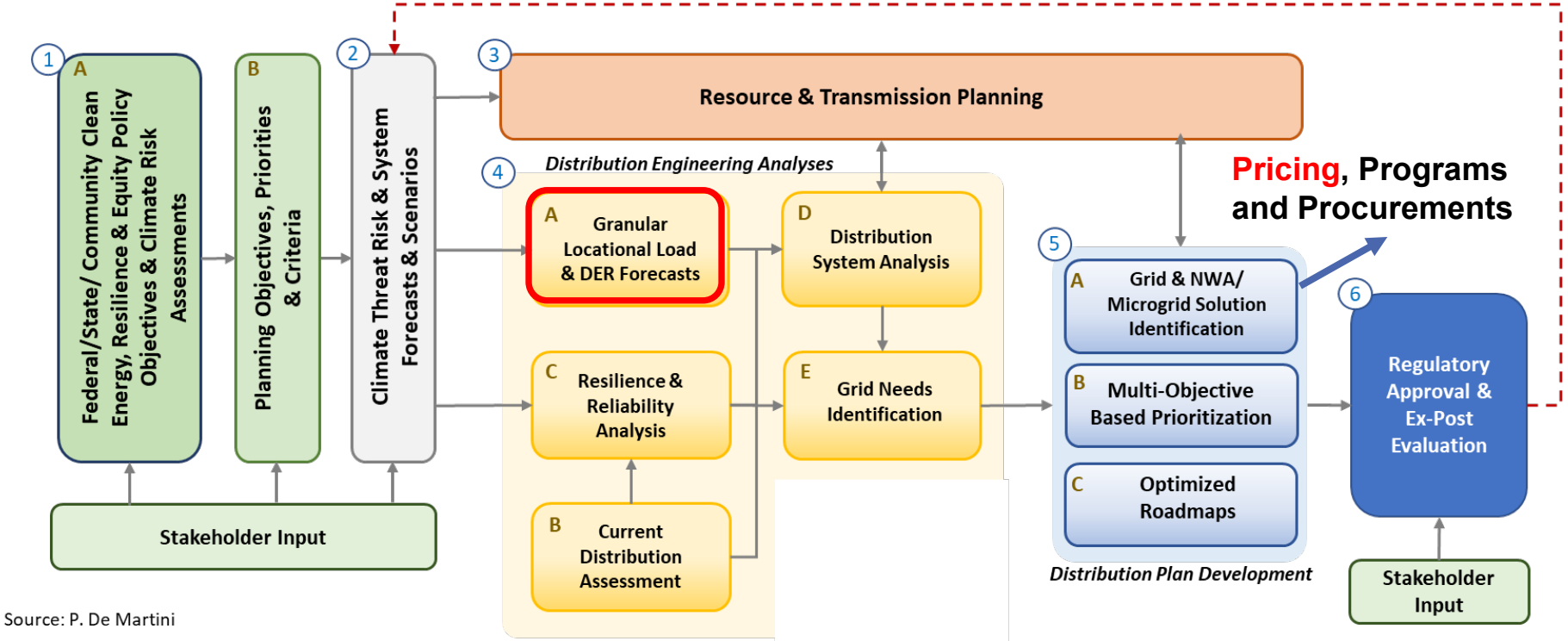


Figure: *State Energy Offices' Engagement in Electric Distribution Planning to Meet State Policy Goals*

Integrated Distribution System Planning Framework



Source: P. De Martini

Source: P. De Martini et al. *Integrated Resilient Distribution Planning*, prepared for U.S. Department of Energy, 2022

Locational Value of Price-Based DR

Price-based DR, **geographically-targeted**, can help meet distribution system needs, including for load relief, voltage regulation, and resilience.

- Potential value of DR at a specific location is determined by:
  - **Capability** to provide needed grid services at that location
  - **Potential avoided costs** of traditional utility distribution investment
- **Deferral value** is the primary location-specific benefit
  - DR must operate at **specific times and locations** where there is a risk that distribution capacity is insufficient to meet expected future needs
- **Electrification** and increasing levels of **distributed generation** are driving investments in distribution systems
  - Accurately valuing all potential solutions — including price-based DR — is increasingly important to **keep down distribution system costs**

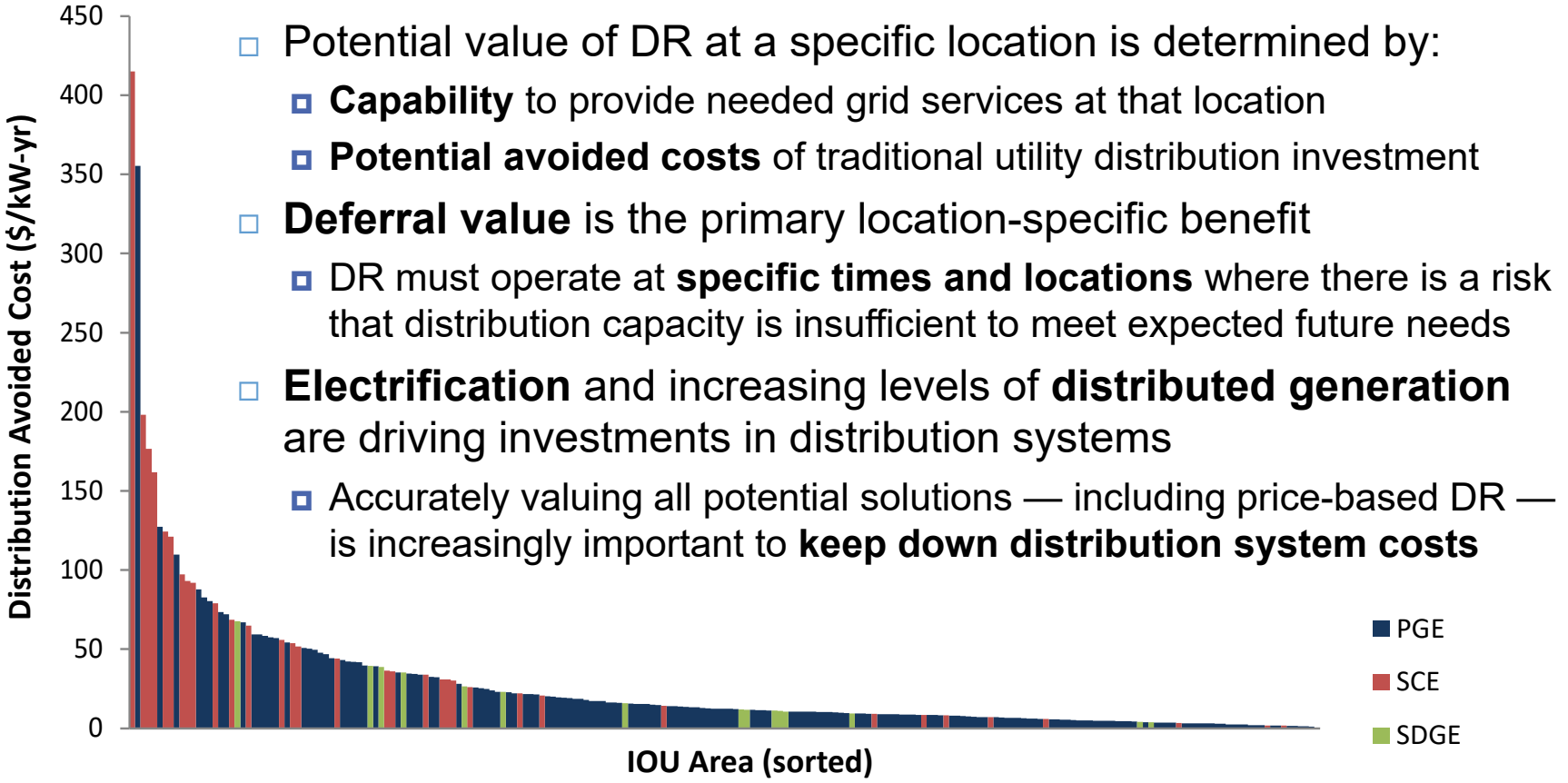
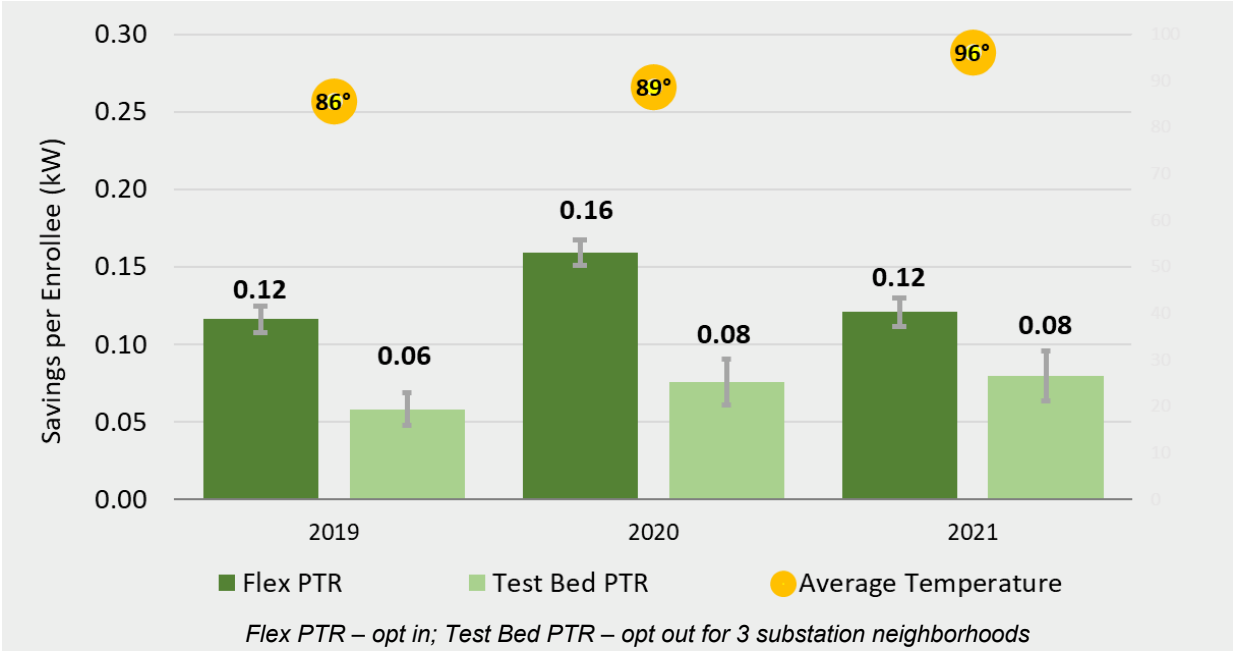


Figure: E3. 2012. Technical Potential for Local Distributed Photovoltaics in California

Prices to Devices: Example Pilots and Programs Using Location-Based Price Signals

- Southern California Edison (SCE) Flexible Pricing Rate Pilot
- San Diego Gas & Electric Power Your Drive program for Level 2 charging ports at workplaces and multi-family dwellings
- Xcel Energy Geotargeted Distributed Clean Energy Initiative
- Consolidated Edison Smart Home Rate Demonstration Project
- Portland General Electric (PGE) Smart Grid Test Bed, with peak time rebate (PTR)

PGE Average Summer Demand Savings (kW) by PTR Group



Flex PTR – opt in; Test Bed PTR – opt out for 3 substation neighborhoods

Considering Price-Based DR in Distribution Plans (1)

If a utility considers price-based DR in distribution planning, it's typically through **pilots**, **forecasting**, and **non-wires alternatives (NWA) analysis**.

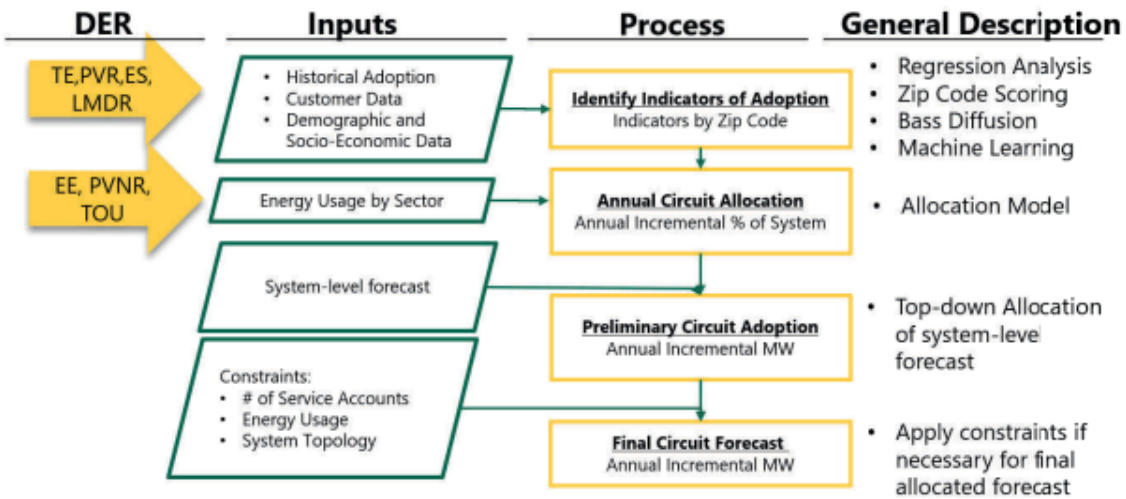
IDP is an important venue to tee up time-varying rate pilots.

- For utilities that **lack sufficient experience with time-based rates** to be willing to count on it **to reduce peak demand for distribution systems**
- For example, the Xcel Energy (Minnesota) 2021 IDP discussed potential time-varying rate pilots for general service customers and EV charging to help meet distribution system needs.
  - Commission ***approved*** **pilots and tariff modifications in other dockets**
  - Commission's order on 2021 IDP required Xcel to "Develop a methodology for valuing the load-modifying impacts of demand response in load forecasts and present a load forecast that includes demand response contributions" (Docket M-21-694)

Considering Price-Based DR in Distribution Plans (2)

Utility load forecasts can be disaggregated by location.

- Utilities can consider impacts of price-based DR on future loads at system and substation circuit level
  - Hawaiian Electric 2023 Integrated Grid Plan evaluates **impact of residential TOU forecasts on a range of modeling scenarios**
  - California investor-owned utilities **allocate to distribution circuits** utility-wide forecasts from the California Energy Commission for efficiency, solar PV, energy storage, demand response, and time-based rates. For example, SCE disaggregates system-level "Load-modifying DR" (defined as CPP) to develop circuit-level forecasts.



Considering Price-Based DR in Distribution Plans (3)

NWAs (aka *non-wires solutions*)

- Can meet some types of distribution (and transmission) system needs
- Provide load relief, reduce power interruptions, address voltage issues, enhance resilience, or meet local energy needs
- May be a single large DER (e.g., battery) or a portfolio of DERs
- The utility first performs a grid needs assessment to determine the location and timing of constraints on the distribution

- 16 states (CA, CO, CT, DE, HI, IL, MA, ME, MI, MN, NV, NY, OR, RI, VA and VT) and DC require regulated utilities to conduct some type of NWA analysis*

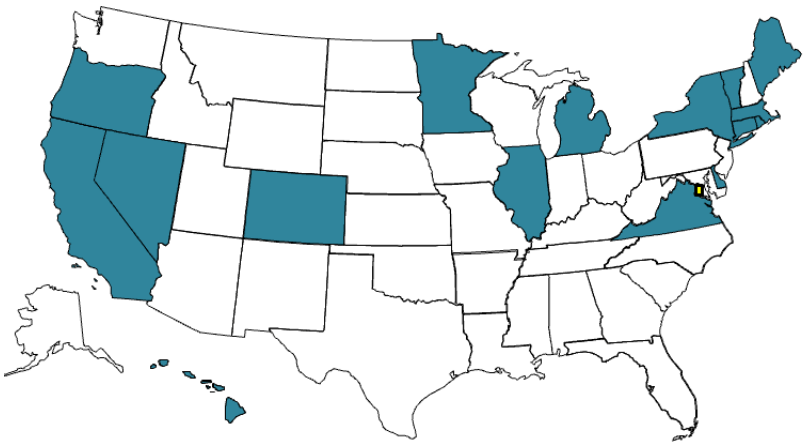


Figure: Berkeley Lab

*In some cases, requirements are only for pilot analyses.

Considering Price-Based DR in Distribution Plans (4)

- **NWA analysis** generally includes 4 steps: (1) identify eligible DER types, (2) determine if NWA passes screening criteria, (3) evaluate whether NWA is a cost-effective solution to identified grid need, and (4) procure solution
  - Procurement typically through utility solicitations for 3rd party solutions
- Utilities also can conduct ***systematic* studies** of the locational value of DR to target time-varying pricing, **reducing load growth in certain areas and the risk that distribution system upgrades will be needed**.

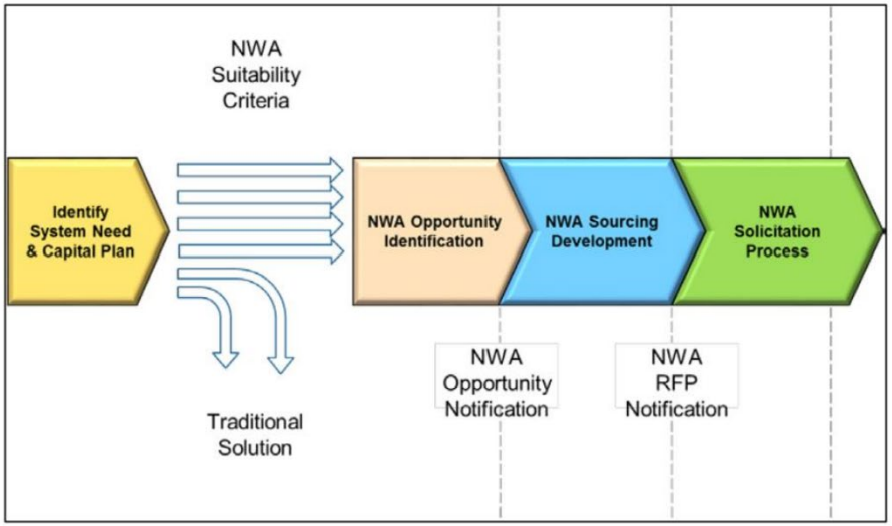
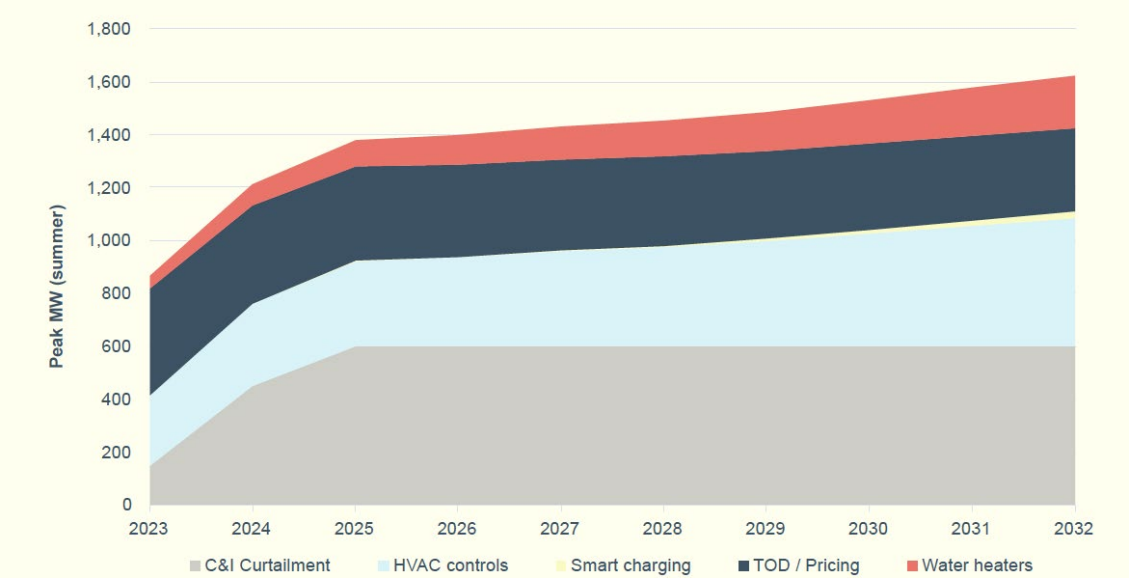


Figure: Orange and Rockland Utilities, Distributed System Implementation Plan, June 30, 2023

Considering Price-Based DR in Distribution Plans (5)

- Consideration of price-based DR as NWAs is nascent.
  - **Price-based DR does not fit into typical NWA procurement processes**, since the utility itself is responsible for retail rates for distribution.
  - But **utility NWA analysis can include time of day (TOD) rates** for distribution charges.
- Example: PGE 2022 IDP and flexible load study
  - Demonstrated that price-based DR, including opt-in TOD and PTR — combined with programmatic approaches to DR and energy efficiency, distributed PV and storage — could meet identified requirements for providing capacity relief for Eastport substation

Flexible Load and DR Potential for PGE's Eastport Substation



Example Recommendations for Considering Price-Based DR in DSP*

- **Evaluate price-based DR** to defer certain distribution system investments and meet new loads
- **Add a dynamic rate** to help address local distribution events
- Consider **financial performance incentives** for utility shareholders to align their interests with utility customers
- Improve **grid data** and make it publicly available
- Apply **advanced planning tools**
- Use a **longer planning horizon**

*See technical brief for additional and detailed recommendations

Q&A

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Contacts

Juan Pablo Carvallo: JPCarvallo@lbl.gov
Lisa Schwartz: lcschwartz@lbl.gov

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Acknowledgements

This work was funded by the U.S. Department of Energy Office of Electricity under Contract No. DE-AC02-05CH11231. We thank Joe Paladino for his support of this work.

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