Distribution System Planning & Non-Wires Alternatives

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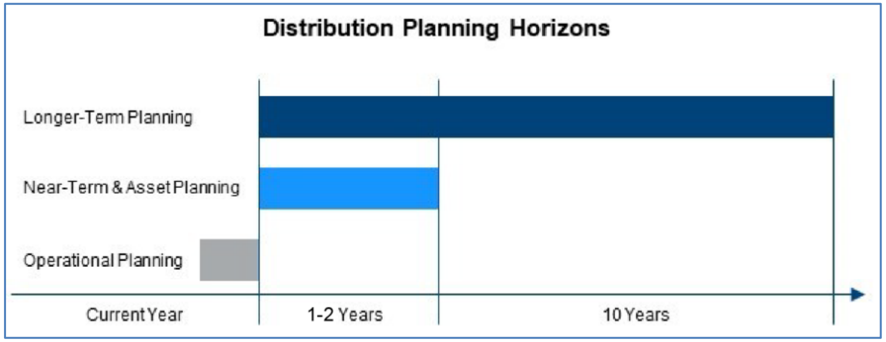
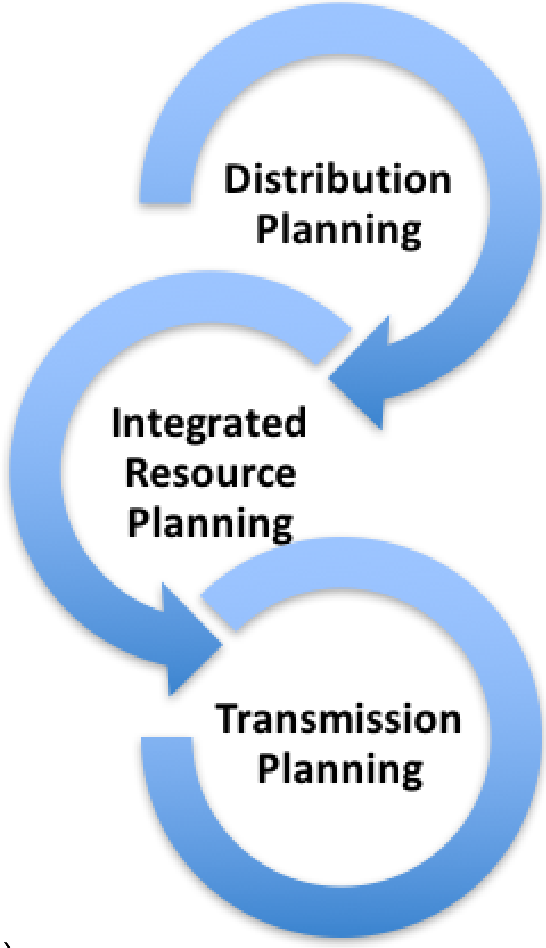
Planning Elements and State Requirements

Electricity system planning

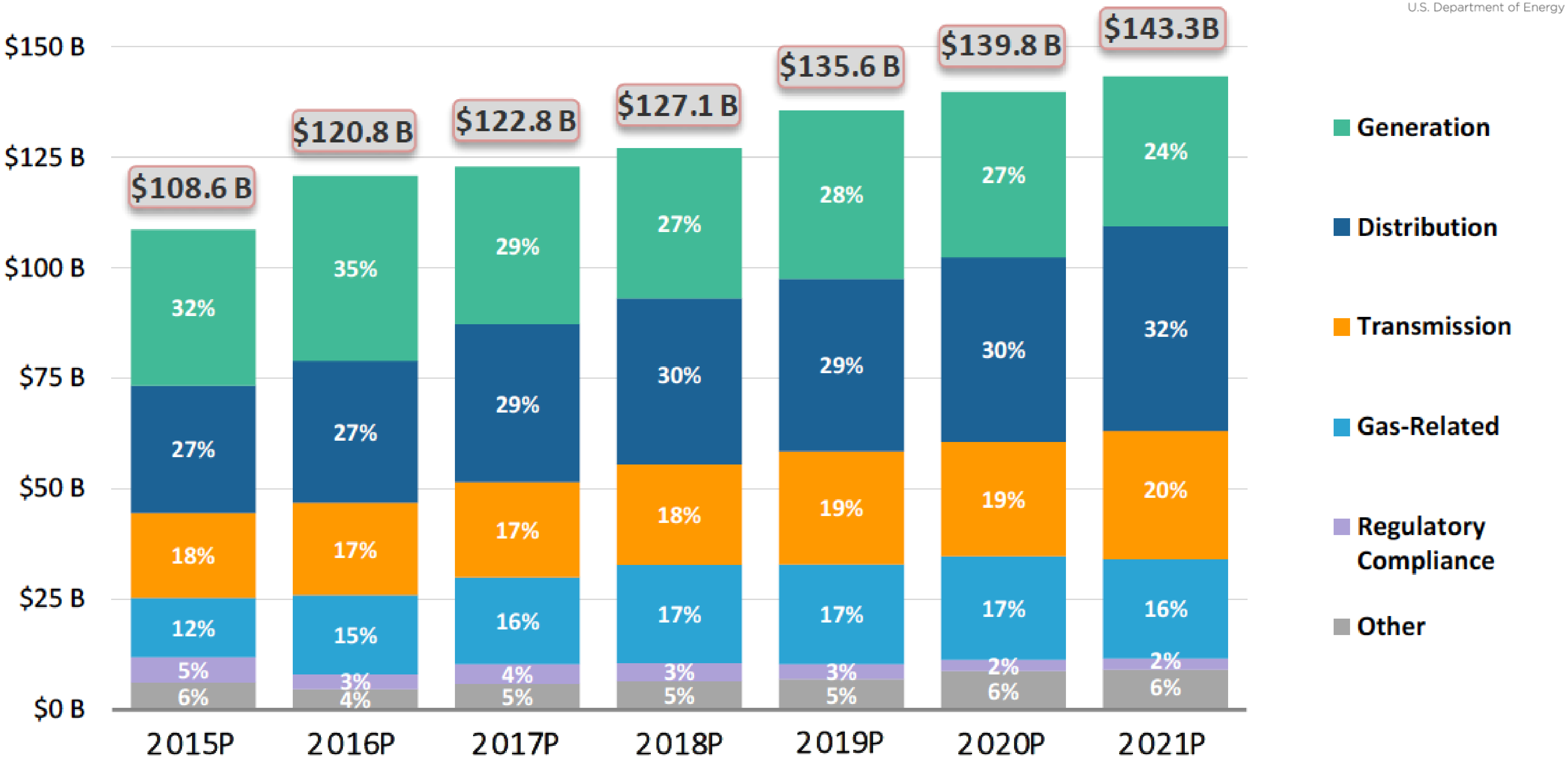


- ► Distribution planning - Assess needed physical and operational changes to the local grid
  - ■ Annual process, with 1–2 year planning horizon*
    - Identify and define distribution system needs
    - Identify and assess possible solutions
    - Select projects to meet system needs
  - ■ Longer-term utility capital plan
    - Includes solutions and cost estimates, typically over a 5- to 10-year period, updated every 1 to 3 years
- ► Integrated resource planning (IRP)* - Identify future investments to meet bulk power system reliability and public policy objectives at a reasonable cost
  - ■ Consider scenarios for loads and distributed resources; impacts on need and timing for utility investments
- ► Transmission planning – Identify future transmission expansion needs and options



Also: energy efficiency, demand-side management, electrification and climate plans
*Operational planning addresses immediate concerns (intraday through the current year).

One reason states are increasingly interested in distribution planning

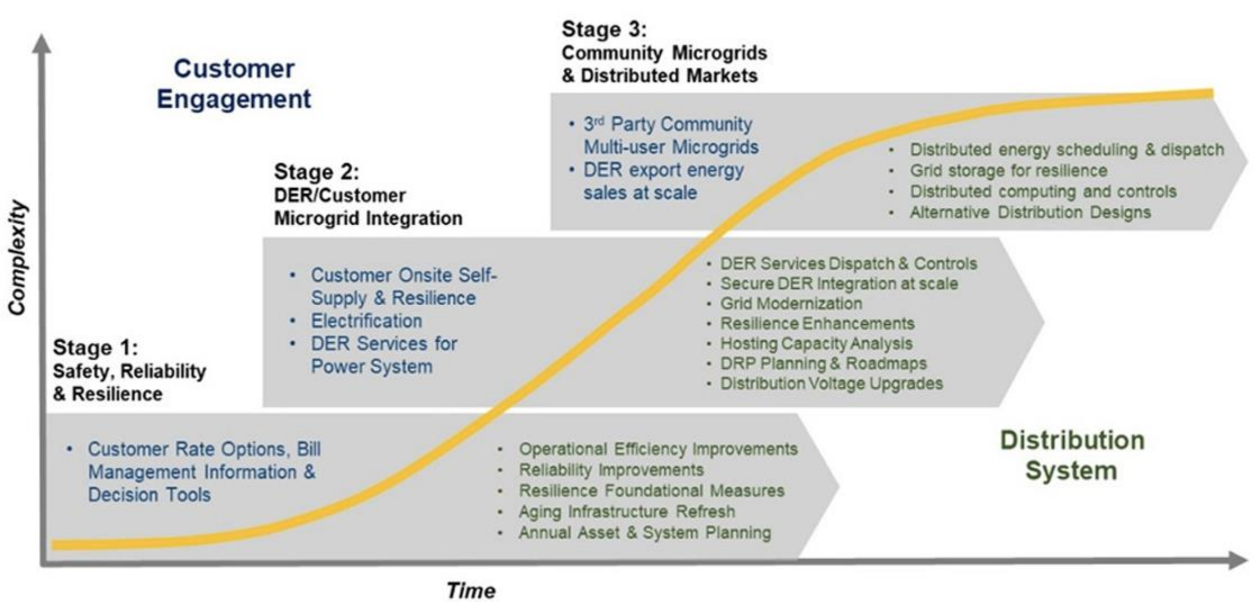


Distribution system investments account for the largest portion (32%) of capex for U.S. investor-owned utilities: $46.4B (projected) in 2021.

Source: [Edison Electric Institute]

Other potential benefits from improved distribution planning processes

- ► Makes transparent utility plans for distribution system investments holistically, before showing up individually in a rider request or rate case
- ► Provides opportunities for meaningful PUC and stakeholder engagement
  - Can improve outcomes — more data, community input, review
- ► Considers uncertainties under a range of possible futures
- ► Considers all solutions for least cost/risk
- ► Motivates utility to choose least cost/risk solutions
- ► Enables consumers and 3rd party providers to propose grid solutions and participate in providing grid services



Source: DOE 2021

States with distribution planning requirements

	California	Colorado	Delaware	District of Columbia	Florida	Hawaii	Illinois	Indiana	Maine	Maryland	Massachusetts	Michigan	Minnesota	Nevada	New Hampshire	New Jersey	New York	Ohio	Oregon	Pennsylvania	Rhode Island	Texas	Utah	Vermont	Virginia	Washington
Distribution system plan requirement	●	●	●	●		●	●	●	●	●	●	●	●	●	●		●		●		●			●	●	●
Grid modernization plan requirement	●					●					●		●				●	●								
Hosting capacity analysis/mapping requirement	●	●				●					●	●	●	●	●		●		●							
Non-wires alternatives / locational value requirements	●	●	●	●		●			●			●	●	●	●		●				●					
Storage Mandates or Targets	●						●		●		●			●		●	●		●						●	
Benefit-Cost Methodology / Guidance	●						●			●				●			●				●					
Storm hardening requirements					●					●															●	
Required reporting on poor-performing circuits and improvement plans		●	●		●		●			●	●		●			●	●	●	●	●	●	●	●	●		●

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Distribution plans may be incorporated in integrated resource plans or integrated grid plans. Grid modernization plans may be filed in combination with distribution plans. This list is not all-inclusive.

Example state requirements*

- Distribution system plans
  California, Colorado, Delaware, DC, Hawaii, Illinois, Indiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Hampshire, Nevada, New York, Oregon, Rhode Island, Vermont, Virginia, Washington
- Grid modernization plans
  California, Hawaii, Massachusetts Minnesota, New York, Ohio
  - Utilities in other states have filed grid modernization plans absent requirements (e.g., GA, NC, SC, TX).
- Hosting capacity analysis/maps
  California, Colorado, Hawaii, Massachusetts, Michigan, Minnesota, Nevada, New Hampshire, New York, Oregon
- NWA/locational value
  CA, CO, DE, DC, HI, ME, MI, MN, NV, NH, NY, RI
- Benefit-cost handbook/guidance
  CA, DC (draft), IL, MD, NV, NY, RI, SC
- States using or considering adopting NSPM framework
  - AR, CO, CT, DC, MD, MI, MN, MO, NH, NJ, RI, PA, WA

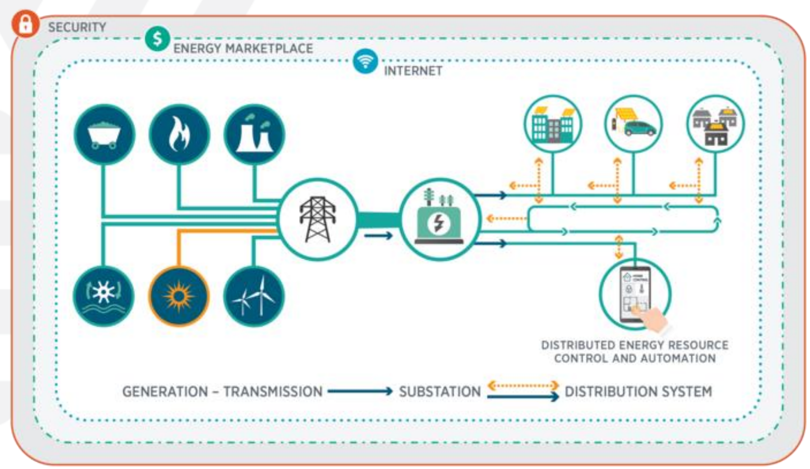
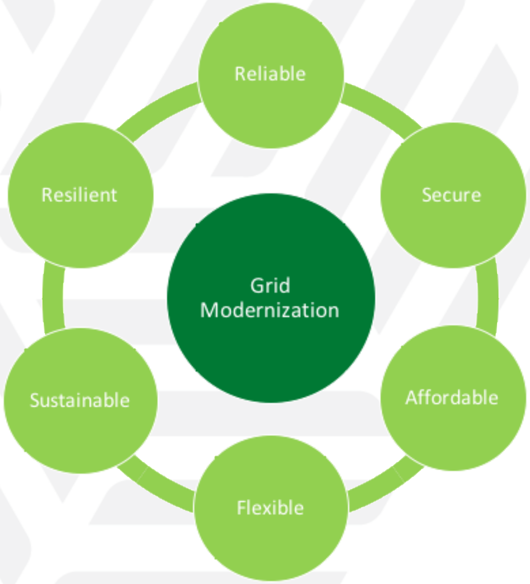


Figure: U.S. Department of Energy

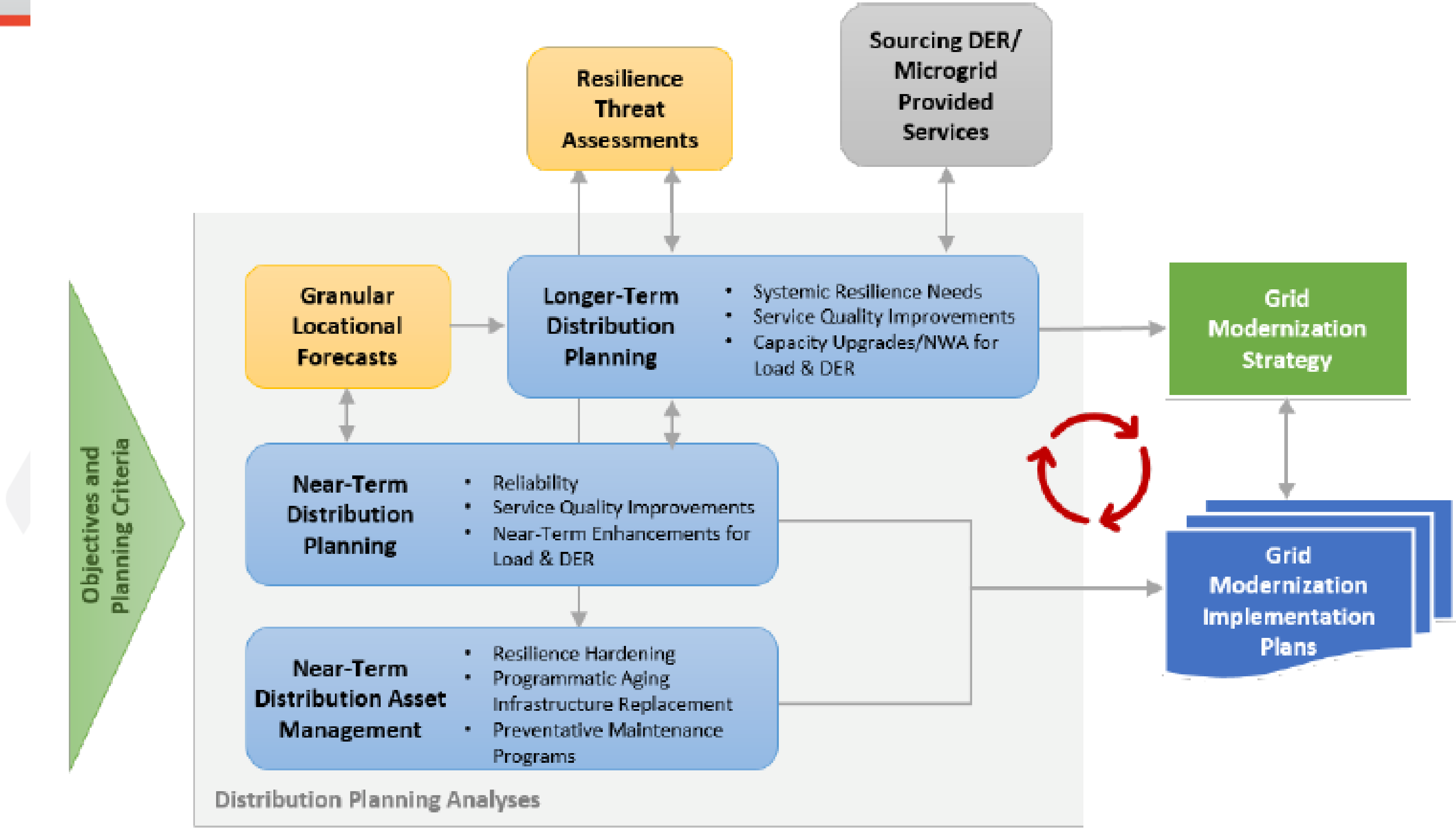
*This list is not all-inclusive.

Grid Modernization and Distribution Planning



Source: U.S. Department of Energy's *Grid Modernization Multi-Year Program Plan*

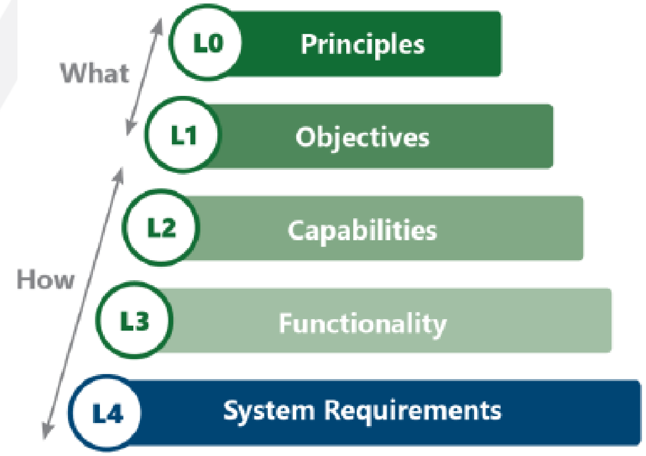
Relationship of grid modernization planning to integrated distribution planning



Source: DOE 2021

Start with principles and objectives instead of picking technologies

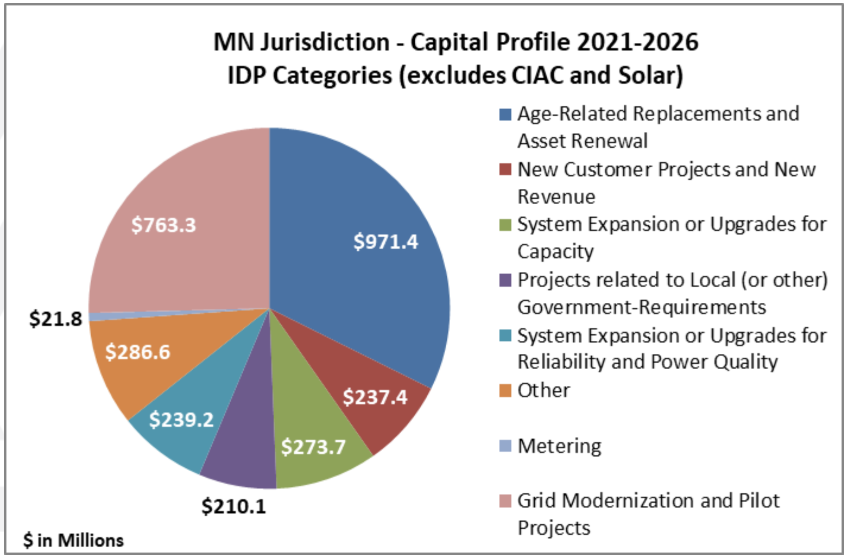
- Grid modernization planning starts with principles, objectives and capabilities needed. They determine functionality and system requirements.
- Holistic, long-term planning for grid modernization is needed to:
  - Support state goals, including reliability, resilience, affordability, clean energy resources, climate and electrification (e.g., AMI for time-varying rates that provide demand flexibility to integrate more wind and solar)
  - Address interdependent technologies and systems, including “platform” components (e.g., Advanced Distribution Management Systems, Geographic Information System, Outage Management System) needed to enable or support other grid modernization projects
  - Consider proactive grid upgrades to facilitate customer choice
- Other plans may feed into distribution plans:
  - Electrification plan informs grid needs for EV charging
  - Cybersecurity plan identifies resilience threats that distribution planning can consider
  - Demand-side management plan specifies capabilities that distribution technologies and systems should provide to achieve multi-year targets for demand response, energy efficiency and conservation



Source: DOE 2021

How one state put together the pieces: Minnesota (1)

- ► Minn. Stat. §216B.2425 (2015) requires the largest utility (Xcel Energy) to submit biennial transmission and distribution plans to the PUC
  - ■ To *"identify … investments that it considers necessary to* ***modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities*** *…."*
  - ■ May ask Commission to **certify priority projects and approve costs through a rider** — a finding that the project is consistent with requirements of this statute, not a prudency determination
  - ■ Analyze hosting capacity for *small-scale distributed generation resources* and *identify necessary distribution upgrades to support [their] continued development*
- ► Xcel Energy 1st grid modernization report (Docket 15-962)
- ► Xcel Energy 2nd grid modernization report (Docket 17-776)
- ► The Commission certified investments in:
  - ■ Advanced Distribution Management System (ADMS)
  - ■ Residential Time of Use Pilot using AMI
  - ■ Field Area Network (FAN)

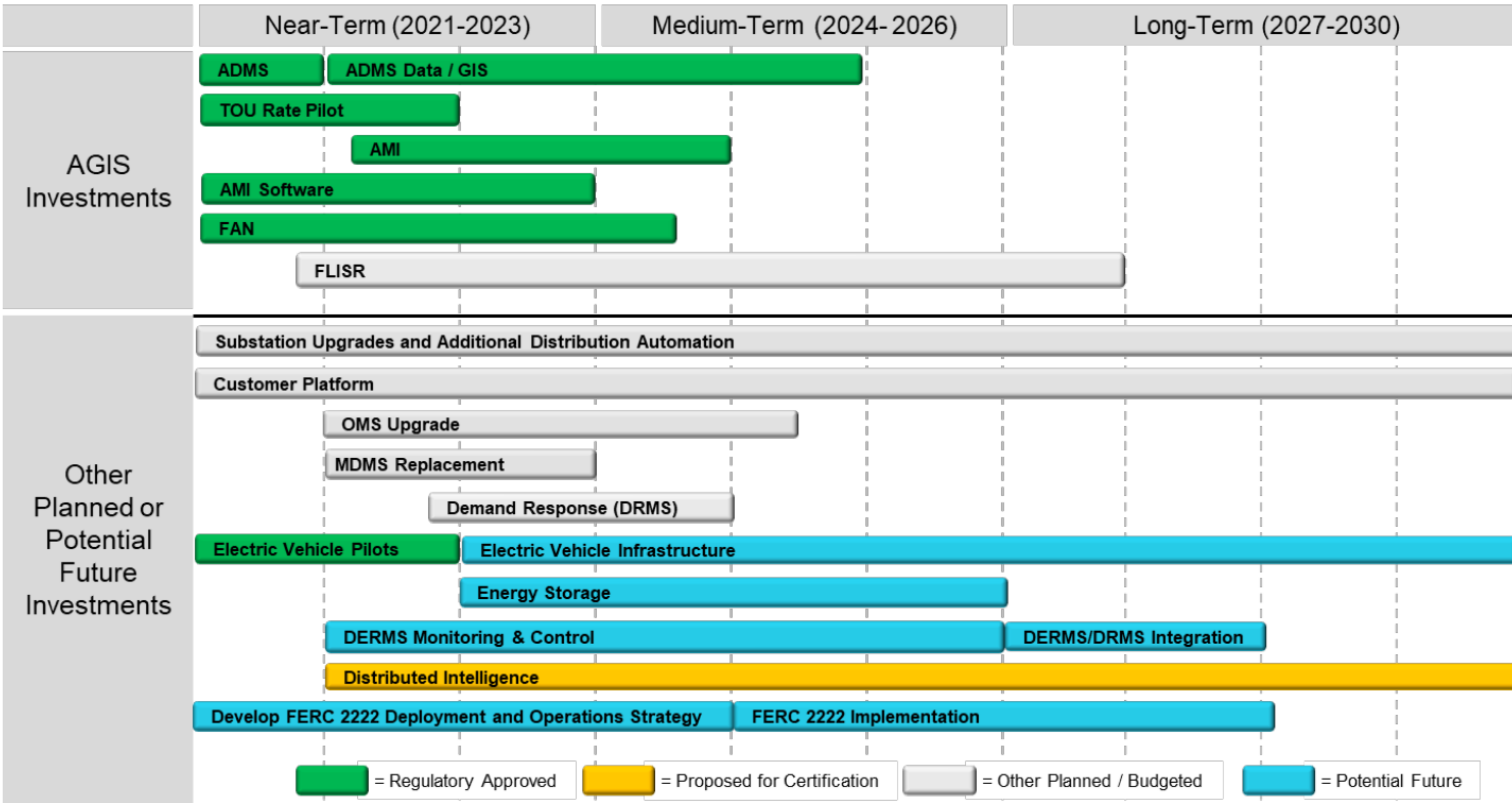


Xcel Energy 2021

How one state put together the pieces: Minnesota (2)

- ► The PUC initiated an inquiry on Electric Utility Grid Modernization with a focus on distribution planning (Docket CI-15-556)
  - ■ Series of stakeholder meetings
  - ■ Questionnaire to utilities on utility planning practices plus stakeholder comments
    - • How do Minnesota utilities currently plan their distribution systems?
    - • What is the status of each utility's current plan?
    - • How could the utility's planning processes be improved or augmented?
  - ■ Staff Report on Grid Modernization defined grid modernization for Minnesota, proposed a phased approach, and identified principles to guide it.
- ► The Commission set Integrated Distribution Planning requirements for Xcel Energy (Docket 18-251) and smaller regulated utilities (Dockets 18-253, 18-254 and 18-252).
- ► Xcel Energy filed the 1st DSP in 2018 (Docket 18-251), a 2nd IDP in 2019 (Docket 19-666), and a 3rd IDP in 2021 (Docket 21-694).
  - ■ **Grid modernization plan now filed *with* IDP filing**

Illustrative Long-Term Grid Modernization Plan



Source: Xcel Energy 2021

DERs and Distribution Planning

Proactive planning is more effective.

Tell customers where the grid needs help and what services the grid needs. Provide appropriate incentives.

- *Load and DER forecasting* helps resource planners avoid overbuilding and feeds into analysis of which feeders may be stressed by DER in the near-term.
- *Hosting capacity analysis* shows how much more DER can be managed on a given feeder easily and where interconnection costs will be low/high.
- Together, these processes identify feeders that are likely to see DER growth and can be considered for proactive upgrades.
- *Locational net benefits analysis* helps determine the benefits of specific services at a specific location to guide developers.
- Cost-effective *non-wires alternatives* are DERs that provide specific services at specific locations can defer some traditional infrastructure investments, leveraging customer and third-party capital investments. DERs like energy efficiency and demand response can make more hosting capacity available.
- These analyses can inform rates and tariffs.

Source: Adapted from Debbie Lew, Emerging distribution planning analyses, prepared for Berkeley Lab, 2020

What is hosting capacity?

- Amount of DERs that can be interconnected without adversely impacting power quality or reliability under existing control and protection systems and without infrastructure upgrades
- Analysis shared by utility typically in maps with supporting data
- Three main constraints: thermal, voltage/power quality, protection limits

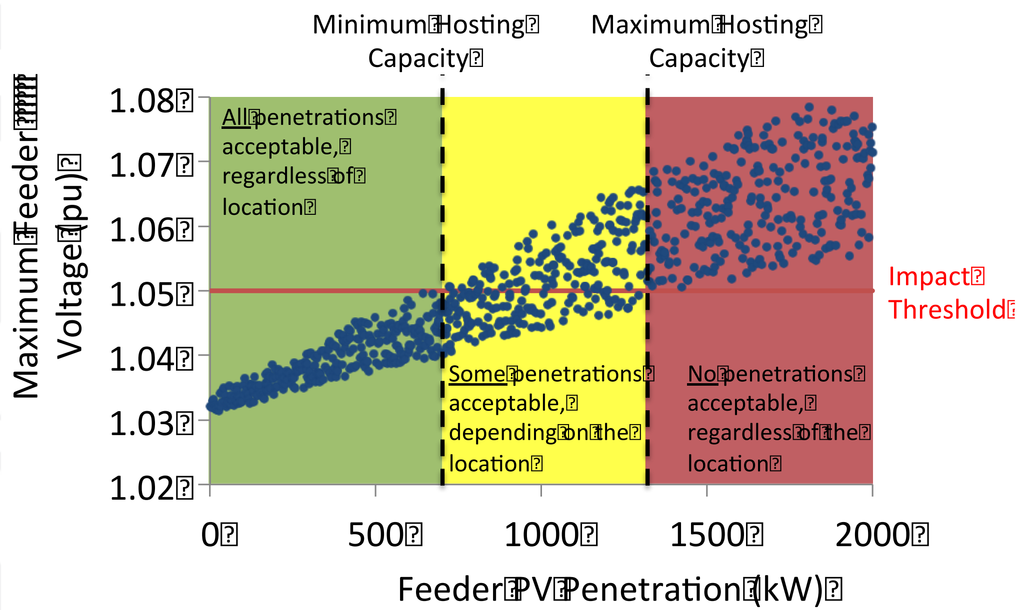


Figure adapted by Berkeley Lab from EPRI (2015), *Distribution Feeder Hosting Capacity: What Matters When Planning for DER?*

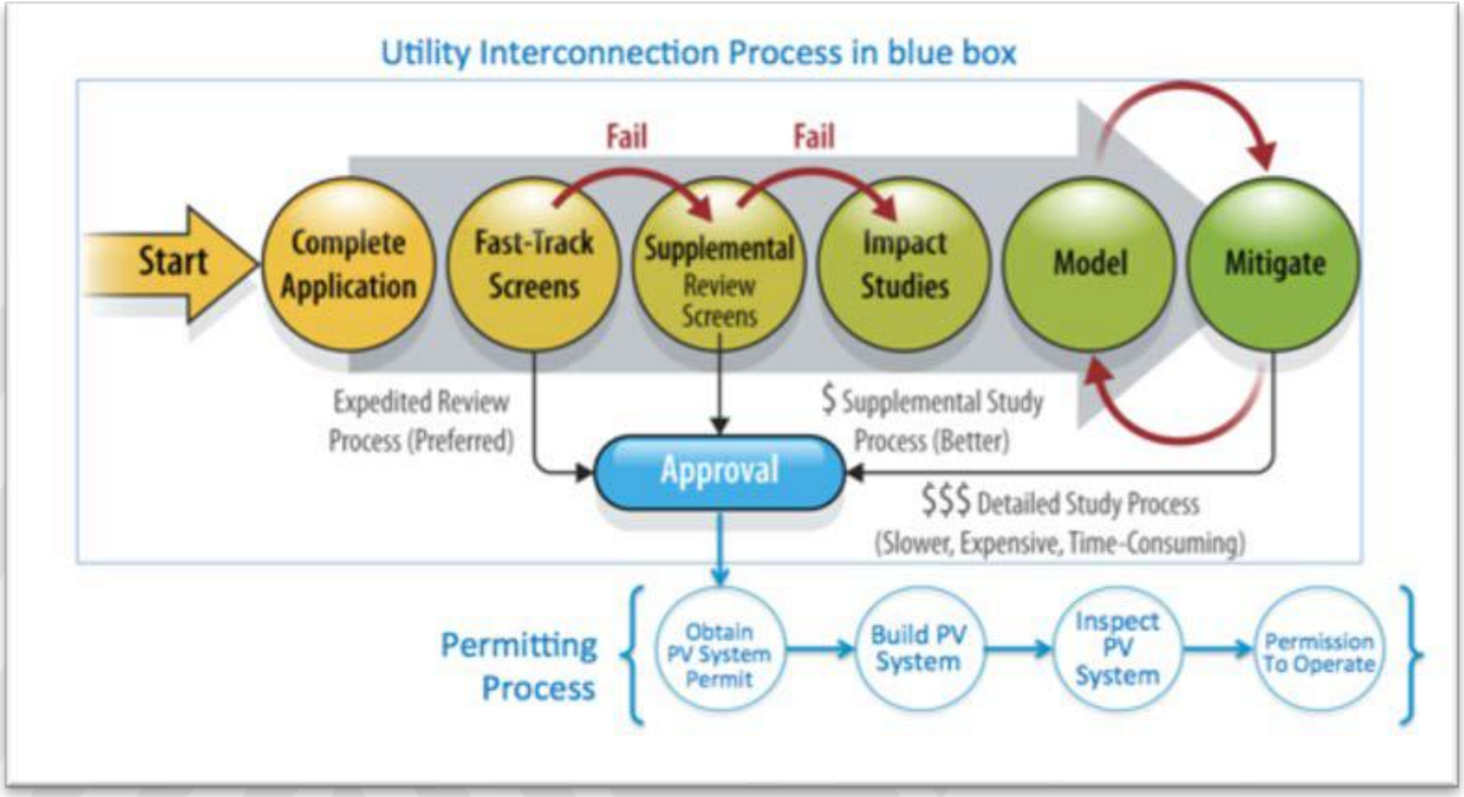
Hosting capacity use cases

	Use Case	Objective	Capability	Challenges
Hosting Capacity Analysis Use Cases	**Development Guide**	Support market-driven DER deployment	Identify areas with potentially lower interconnection costs	Security concerns; analysis/model refresh; data accuracy and availability
	Technical Screens	Improve the interconnection screening process	Augment or replace rules of thumb; determine need for detailed study	Data granularity; benchmarking and validation to detailed studies
	Distribution Planning Tool	Enable greater DER integration	Identify potential future constraints and proactive upgrades	Higher input data requirements; granular load and DER forecasts

Source: ICF International for DOE

Useful reference: IREC, *Key Decisions for Hosting Capacity Analysis*, 2021

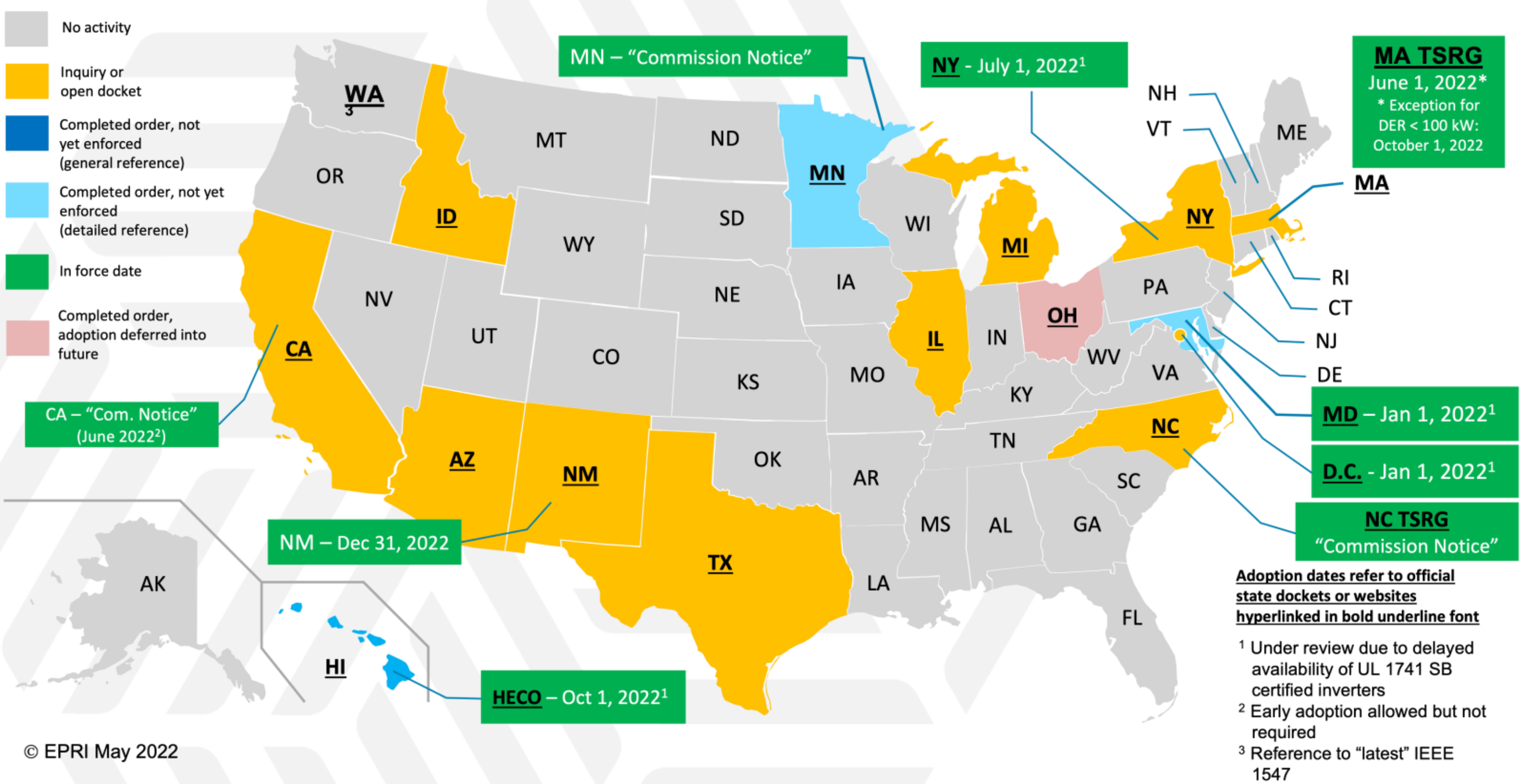
Interconnection process



Systems above a certain size may skip the Fast-Track Screens and go straight to detailed Impact Studies

Source: Horowitz et al., *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions*, April 2019, National Renewable Energy Laboratory

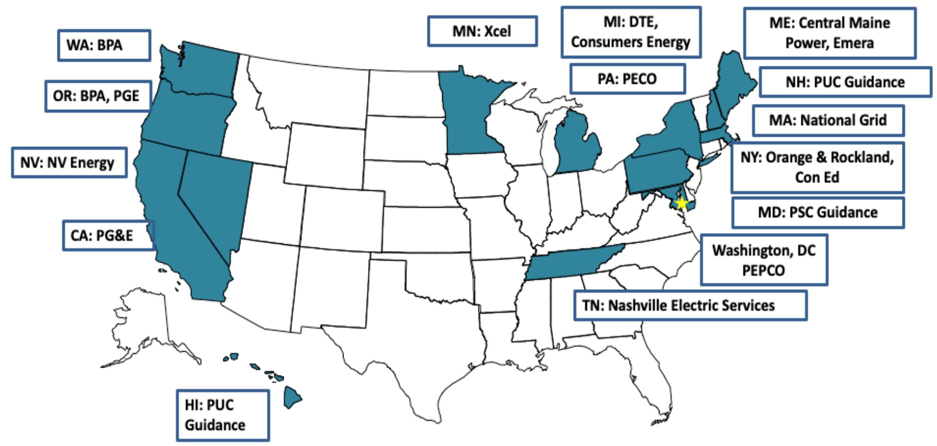
U.S. states adopting IEEE Standard 1547-2018



Source: EPRI, "IEEE Std 1547™-2018: Status of Adoption across the U.S.," May 2022.
See Extra Slides for ISO/RTO adoption and state resources on interconnection.

What are non-wires alternatives?

- Options for meeting distribution system needs related to load growth, reliability and resilience.
  - Single large DER (e.g., battery) or portfolio of DERs that can meet the specified need
- Objectives: Provide load relief, address voltage issues, reduce interruptions, enhance resilience, or meet local generation needs
- Potential to reduce utility costs
  - Defer or avoid infrastructure upgrades
  - Implement solutions *incrementally,* offering a flexible approach to uncertainty in load growth and potentially avoiding large upfront costs for load that may not show up.



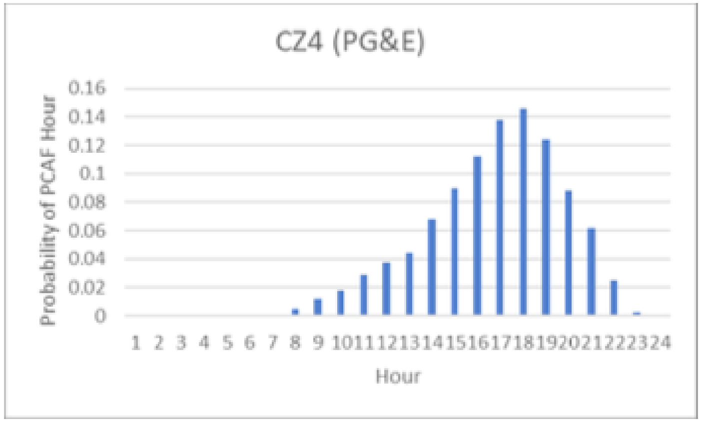
Case studies featured in Berkeley Lab report, *Locational Value of Distributed Energy Resources*

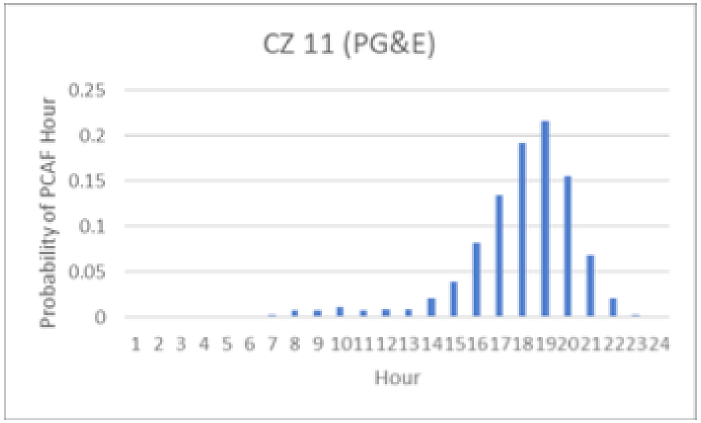
- Typically, the utility issues a competitive solicitation for NWA for specific distribution system needs and compares these bids to planned traditional grid investments to determine the lowest reasonable cost solution.
- Jurisdictions that require NWA consideration include CA, CO, DE, DC, HI, ME, MI, MN, NV, NH, NY and RI. Other states have related proceedings, pilots or studies underway.

Locational value of DERs

- In addition to analyzing DERs as alternatives to *specific projects*, utilities can conduct *systematic* studies of DER locational value to:
  - Better understand where to target DERs
  - Calibrate incentive levels
  - Reduce load growth for specific areas of the distribution system
  - Reduce the need for traditional distribution system upgrades.
- Locational net benefits analysis systematically analyzes costs and benefits of DERs to determine the net benefits DERs can provide for a given area of the distribution system.
- These studies can become a routine and transparent part of the utility's distribution planning process. Information also can be used for DER programs and rate designs.

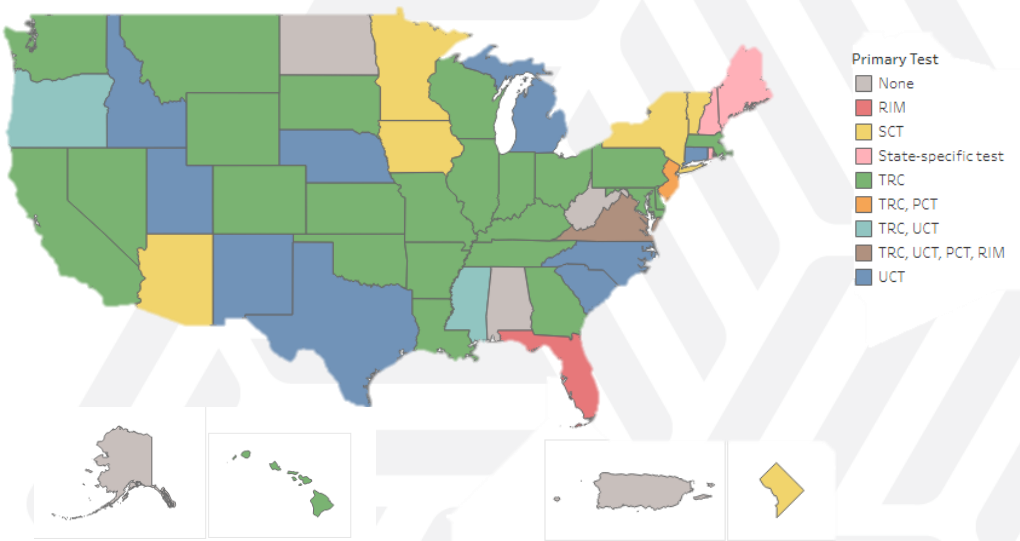
Example PG&E peak capacity allocation factors distribution by hour for climate zone 4 and climate zone 11. Source [Avoided Cost Calculator](#) (2021)





State Benefit-Cost Analysis (BCA) Guidelines

Most Used Benefit-Cost Test by State for DERs



Test	Perspective	Key Question Answered	Categories of Benefits and Costs Included
Jurisdiction-Specific Test	Regulators or decision-makers	Will the cost of meeting utility system needs, while achieving applicable policy goals, be reduced?	Includes the utility system impacts, plus those impacts associated with achieving applicable policy goals
Utility Cost Test*	The utility system	Will utility system costs be reduced?	Includes the utility system impacts
Total Resource Cost Test	The utility system plus host customers	Will utility system costs and host customers' costs collectively be reduced?	Includes the utility system impacts, plus host customer impacts
Societal Cost	Society as a whole	Will total costs to society be reduced?	Includes the utility system impacts, plus host customer impacts, plus societal impacts such as environmental and economic development impacts

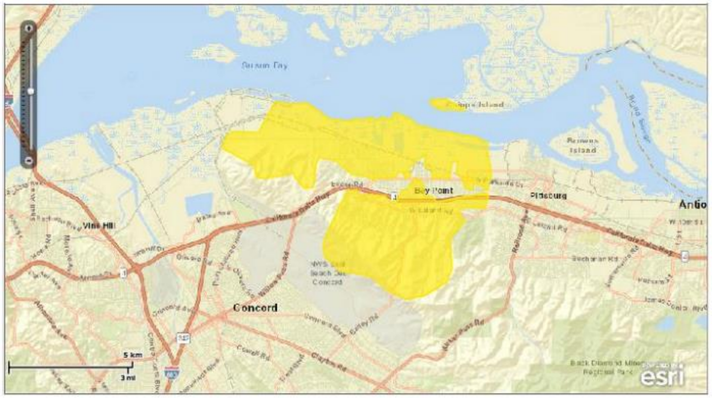
Source NESP, May 2022; August 2020

- Use of cost benefit analysis varies significantly by state
- States have different preferences for metrics and reporting, and some states use multiple metrics
  - Use of these metrics may be a best practice, but not required in some states
- Some states are adopting all or portions of the National Standard Practice Manual to aid in BCA
  - Some states developed new cost test(s) based on NSPM principles
  - Some states kept existing test(s), but changed processes to fit NSPM practices
  - Other states directed utilities to consult the NSPM to answer technical questions (e.g., choice of test, discount rate)

NWA procurement strategies in California

- Three procurement mechanisms identify opportunities to cost-effectively defer or avoid traditional utility investments to use DERs to mitigate forecasted deficiencies:
  1. Distribution Investment Deferral Framework (DIDF) - Annual Grid Needs Assessments and Distribution Deferral Opportunity Reports
     - Examples: SCE, PG&E, SDG&E
     - Following a Distribution Planning Advisory Group stakeholder process, the utilities issue their request for offers (RFO) for competitive annual solicitations for specific deferral projects.
  2. Partnership Pilot (2021) - Utilities prescreen aggregators to procure owned, behind-the-meter (BTM) aggregation improves and accelerates deferral implementation
  3. Standard Offer Contract Pilot - Utilities select offers for front-of-the-meter DERs through a simple auction

Willow Pass Substation Bank 3 Map



Source: PG&E presentation on 2021 RFO

2021 Distribution Deferral Status

- As of February 2021, the CPUC approved 16 MW of battery storage contracts for PG&E and 18.5 MW for SCE.
- PG&E and SCE released their 2021 DIDF RFO in January 2021.
  - Insufficient quantity of viable bids received to meet the full need for any deferral opportunities identified by PG&E or SCE.
- SDG&E, PG&E and SCE filed 2021 DIDF plans in August 2021.
  - SDG&E identified one project that is eligible for deferral and released its 2021 DIDF RFO in December 2021.
- CA investor-owned utilities continue to have challenges successfully implementing NWA.
- New procurement mechanisms — the Partnership Pilot and Standard Offer Contract — were designed to accelerate procurement timelines to enable successful deployment of NWA.

See Extra Slides for more information.

Partnership Pilot

- Customers participate in the pilot through a pre-screened aggregator.
- Pre-screened aggregators meet experience and financial viability criteria, and have demonstrated the capability to reliably dispatch DERs.
- The pilot is first-come, first-serve. It remains open until the subscription period closes or when the utility contracts 120% of identified need.
- When the utility receives offers that meet 90% of the capacity needed to defer the distribution project, the utility contracts with the aggregators.
- The pilot budget is capped at 85% of the estimated cost per kW of traditional investment.
- Annually, each utility must identify three projects to test the pilot.

Southern California Edison Partnership Pilot Project

Partnership Pilot Project Name: New Circuit at El Casco Substation

Project Cities May Include	Need Area	Tranche	Tranche Status	Tranche Procurement Goal (Capacity - MW)	Tranche Procurement Goal (Energy - MWh)	Subscription Period Launch Date	Subscription Period End Date	Operating Date	Deferral Value (Cost Cap-PV $)	Tariff Budget (Nominal $)	Deployment Budget	Reservation Budget	Performance Budget
Beaumont, Calimesa	Jonagold Circuit	1	Open	0.1	0.1	1/18/2022	12/1/2022	6/1/2024	$65,627	$12,130	$2,426	$3,639	$6,065
		2	Closed	0.3	0.6	~1/15/2023	12/1/2023	6/1/2025	$61,271	$80,056	$16,011	$24,017	$40,028
		3	Closed	0.4	0.7	~1/15/2024	12/1/2024	6/1/2026	$57,205	$102,738	$20,548	$30,822	$51,369
		4	Closed	0.4	0.6	~1/15/2025	12/1/2025	6/1/2027	$53,408	$96,868	$19,374	$29,060	$48,434
		5	Closed	0.3	0.5	~1/15/2026	12/1/2026	6/1/2028	$49,864	$88,795	$17,759	$26,639	$44,398
		6	Closed	0.3	0.3	~1/15/2027	12/1/2027	6/1/2029	$46,554	$58,605	$11,721	$17,581	$29,302
		7	Closed	0.3	0.4	~1/15/2028	12/1/2028	6/1/2030	$43,465	$85,954	$17,191	$25,786	$42,977
									Total Tariff Budget	$525,146			

Standard Offer Contract

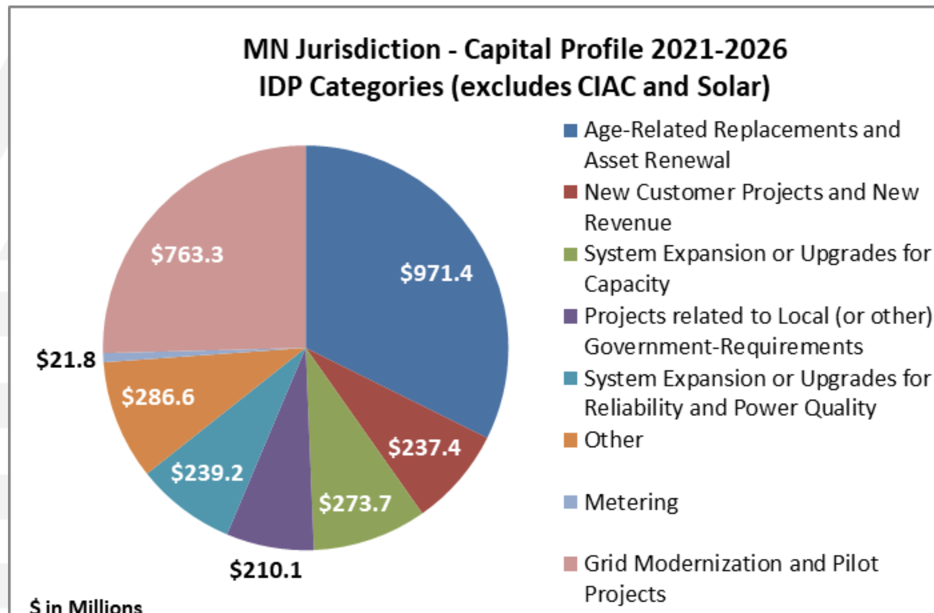
- Participants use a standard contract to offer front-of-the meter DERs to avoid or defer identified utility distribution investments.
  - Contract is based on Technology Neutral Pro Forma contract — for example, SDG&E's contract is here.
  - DERs can be dispatchable or non-dispatchable.
- Participants can submit partial or full offers, and the utility can combine offers together to create a solution. Offers include a $/kW-Month price.
- The offer price cap is the value of a one-year deferral of the planned distribution project, which the utilities publish. Once 90% of the capacity is filled the utilities start the contract process.
- Utilities are required to select one project annually to test the pilot.

Southern California Edison Standard Offer Contract Pilot Project

Project Description	Tier	Location(s) of Need	Distribution Service Required	Operating Date	Max 10-year Capacity Need (MW)	Max 10-year Duration (hr)	Standard Offer Contract Pilot Project Ranking
New Circuit at Eisenhower	Tier 1	Crossley 33kV	Capacity	6/1/2024	2.9	6	1
New Circuit at El Casco Substation	Tier 1	Jonagold 12kV	Capacity	6/1/2024	0.4	2	2
New Circuit at Elizabeth Lake	Tier 1	Guitar 16kV Oboe 16kV Trumpet 16kV	Capacity (UCT) FLAG	6/1/2024	9.0	11	3

NWA in Minnesota

- The Commission set Integrated Distribution Planning (IDP) requirements for Xcel Energy (Docket 18-251) and smaller regulated utilities (Dockets 18-253, 18-254 and 18-252).
  - For projects >$2M, utilities must analyze how non-wires solutions compare with traditional grid solutions in terms of viability, price and long-term value.
  - Utilities must specify distribution system project types (e.g., load relief or reliability) as well as timelines, cost thresholds and screening process for NWAs.
- Xcel Energy's NWA analyses
  - 1st IDP (Docket 18-251)
  - 2nd IDP (Docket 19-666)
  - 3rd IDP (Docket 21-694)



Xcel Energy, *2022-2031 Integrated Distribution Plan*, 2021

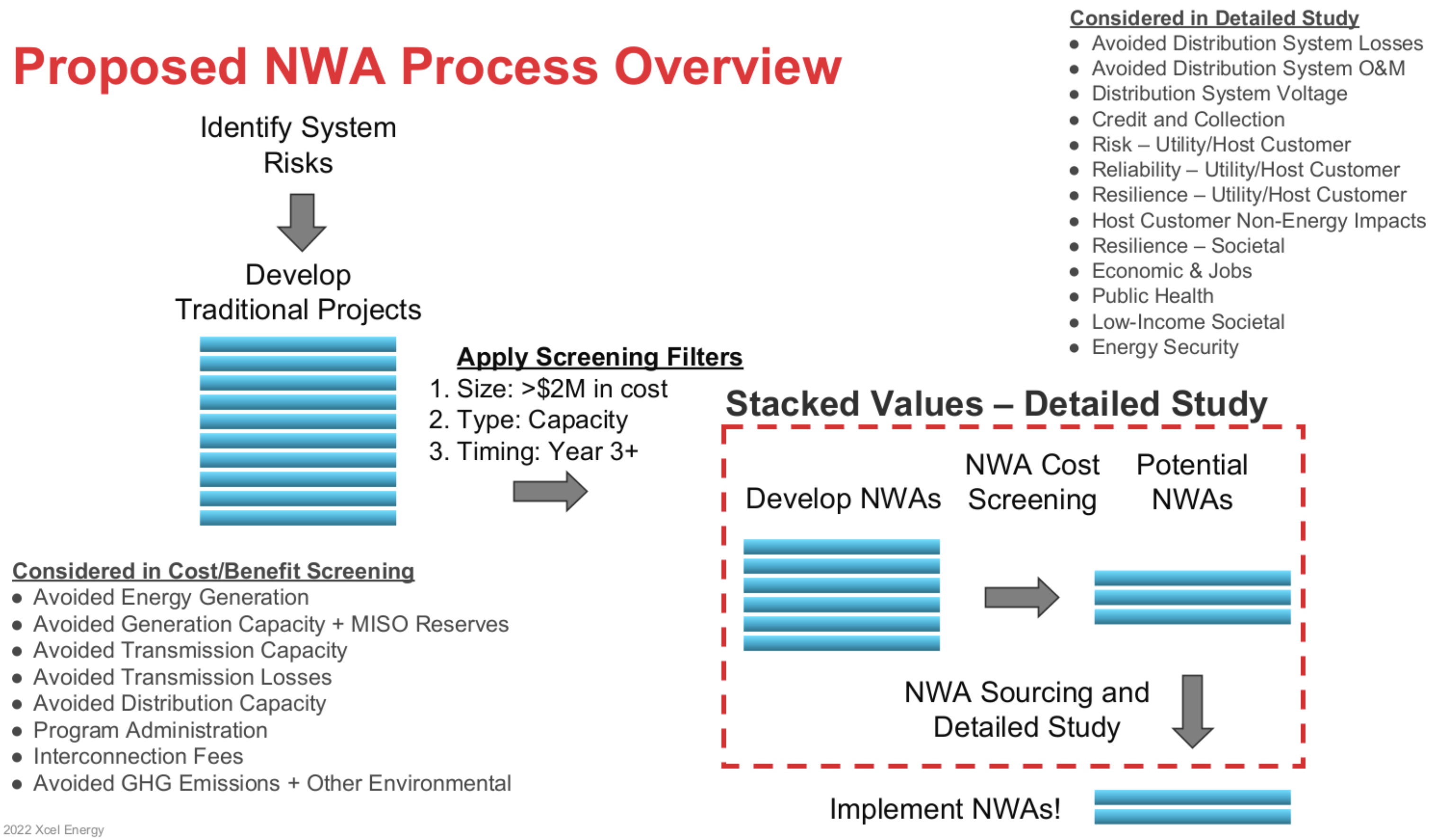
Xcel Energy 2021 Integrated Distribution Plan - NWA analysis results (MN)

Project Title	# of Risks	Aggregate Project Peak Demand (MW Overload)	Aggregate Project Energy Demand (MWh Overload)	Cost of NWA	Cost of Traditional Project
Install Kohlman Lake KOL Feeder	7	11.25	50.39	$17.0	$4.52
Install Viking VKG Feeder	3	10.3	62.6	$17.9	$4.1
Install Wyoming WYO Feeder	5	14.38	97.14	$28.5	$2.5
Reinforce Veseli VES TR1 & Feeder	3	10.99	69.75	$41.8	$2.8
Install Zumbrota ZUM TR	2	10.97	73.34	$41.8	$3.0
Install Chemolite CHE TR03	5	28.82	151.18	$11.8	$4.0
Install Goose Lake GLK TR3 & Feeders	8	29.53	179.03	$37.9	$6.4
Install Orono ORO TR2 & Feeder	3	15.40	279.70	$68.9	$4.1
Reinforce Burnside BUR TR2	3	17.8	135.06	$69.6	$2.7
Install Cottage Grove CGR TR03	4	64.27	321.39	$46.6	$4.2
Install Cannon Falls Trans CTF TR02 & Fdr	4	17.43	141.13	$108.0	$2.0
Install Western WES TR3 & Feeders	9	34.97	185.33	$95.4	$5.3
Reinforce Faribault FAB TR1	5	32.3	234.31	$125.8	$2.0
Install East Winona EWI TR2	6	21.79	166.46	$115.6	$3.2

Xcel Energy, *2022-2031 Integrated Distribution Plan*, 2021

Xcel Energy's Proposed NWA Process for MN (1)

- Xcel Energy held stakeholder workshops in 2021 to identify opportunities to improve its NWA process.
- Stakeholder feedback informed the utility's proposed process changes.



Source: Xcel Energy, 2022

Xcel Energy's Proposed NWA Process for MN (2)

Aspect/Component	Current Method	Proposed Method
Timeframe	Full NWA lifetime	**10-year deferral period***
Ownership Model	Utility ownership	**Load reduction contract or** utility ownership
Load Reduction Requirement	Exact MWh of load at risk on peak day	**Peak output for the duration of the risk**
Stacked Values	No stacked values	**Stacked values included**
Pro-Rating Values	No pro-rating, full values included	**Values pro-rated** for just the load reduction period (ARR split)
Solar Performance	PVWatts TMY simulation for one location in Minnesota	PVWatts TMY simulation for **five locations** in Minnesota

* Subject to change.

Source: Xcel Energy, https://pubs.naruc.org/pub/47B689BC-1866-DAAC-99FB-82CCB3336C2E (slide 42)

New York Distribution System Implementation Plans (DSIP)

- NY PSC DSIP Guidance (April 2018) – Must include sections on:
  - Integrated planning, advanced forecasting, grid operations, energy storage integration, electric vehicle integration, energy efficiency integration and innovation, distribution system data, customer data, cyber-security, DER interconnections, advanced metering infrastructure, hosting capacity, **beneficial locations for DERs and NWAs, and procuring NWAs.**
  - DSIP also must address governance, marginal cost of service studies, and utility's most recent Benefit-Cost Analysis Handbook.
  - Utilities filed their 2nd DSIPs in June 2020; see NYSEG/RG&E; ConEd; O&R; National Grid; Central Hudson.

- The Joint Utilities were initially scheduled to file the 2022 DSIPs in June. The PSC approved their request for an initial extension to December 31, 2022, because of ongoing local transmission and distribution planning in Case 20-E-0197.

NWA procurement strategies in New York (1)

- As part of annual capital planning, each utility must routinely identify candidate projects (load relief, reliability) for non-wires alternatives, post information to websites and issue RFPs. Utilities jointly provided suitability criteria (March 2017) for NWA projects and described how criteria will be applied (May 2017) in capital plans and procurement processes.

Criteria	Potential Elements Addressed	
Project Type Suitability	Project types include Load Relief and Reliability*. Other categories currently have minimal suitability and will be reviewed as suitability changes due to State policy or technological changes.	
Timeline Suitability	**Large Project**	36 to 60 months
	Small Project	18 to 24 months
Cost Suitability	**Large Project**	$\geq$ $1M
	Small Project	$\geq$ $300k

NWA procurement strategies in New York (2)

Projects, Needs and Default Solutions: Orange & Rockland NWA projects

Project	Need	Default Solution	Status
West Warwick **RFP**	Amount: 12MW Location: Wisner Substation #80 When: 2022	Construction of new transmission/distribution substation	Executed contract
Sparkill **RFP**	Amount: 2 MW Location: Circuit 50-3-13 When: 2023	New distribution circuit tie	Procurement process to begin in 2022; in service 2023
Monsey **RFP**	Amount: 15 MW Location: Bank #244 When:2021	Upgrade of Monsey substation	Going through siting and permitting process

See Joint Utilities NWA Opportunities and REV CONNECT

NWA procurement strategies in New York (3)

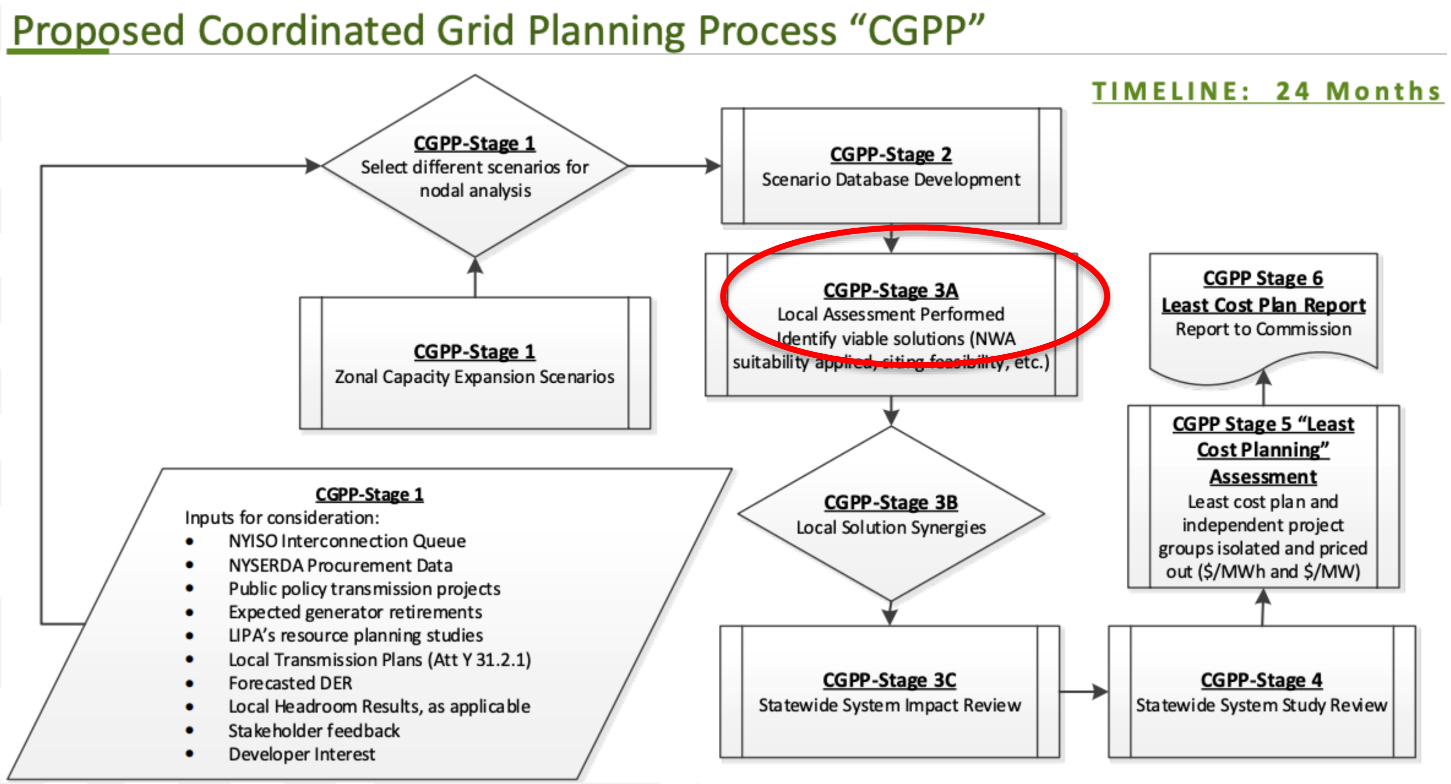
Project	Need	Default Solution	Status
Orange & Rockland Utilities Pomona DER project	Amount: 2 MW Location: 4 circuits in Pomona load area Overload period: 1-7 pm When: 2020 (spring/summer)	Construct Pomona substation	Completed; 4.1 MW peak reduction from EE, DR and battery
Con Edison Brooklyn-Queens Demand Management	Amount: 60 MW (since 2015) Location: Brooklyn and Queens Peak hour: 9-10 pm	Construct Brownsville and Gowanus substations	Ongoing - 60 MW peak reduction to date

Figure 1: Hourly Load Profile of Operational BQDM Customer-Side Solutions and Non-Traditional Utility-Side Solutions. *Note: A 1.5 MW 4-hour utility-side battery energy storage system is not depicted in the load profile as its dispatch varies.*

Source: Con Edison BQDM Quarterly report, May 2022

Coordinated Grid Planning Process in New York

► As part of local T&D planning, the PSC required the utilities to develop a Coordinated Grid Planning Process by December 2022.



Source: Joint Utilities CGPP presentation, May 2022

► The process will develop a cost-effective transmission plan for achieving state decarbonization goals (100% clean energy by 2040) and will consider trade-offs between generation, transmission and NWAs.

Nevada

Non-Wires Alternative Suitability/Screening
Critical Suitability Criteria
Is the constraint anticipated to occur between January 1, 2021 and December 31, 2026?
Is the constraint based upon thermal loading, voltage, or reliability reasons where a reduction in peak demand loading or energy consumption, or load shifting, on the transmission or distribution facilities involved would eliminate or defer the constraint?
Red Flag Suitability Criteria
Is the wired solution still within the planning or design stage, with no major equipment on order, received, or installed?
Is it reasonable to assume at this time that a Distributed Energy Resources solution will be reliable and safe (i.e., non-critical customers) in this location on the grid?
Is it reasonable to assume at this time that local residents would accept a Distributed Energy Resources solution in this area?
Is it reasonable to assume at this time that local government agencies would accept a Distributed Energy Resources solution in this area?
Is it reasonable to assume at this time that there are no environmental concerns which would preclude a Distributed Energy Resources solution in this area?
Is it reasonable to assume at this time that a Distributed Energy Resources solution would be able to be physically located in this area?

Source: [NV Energy 2020 Distribution System Plan]

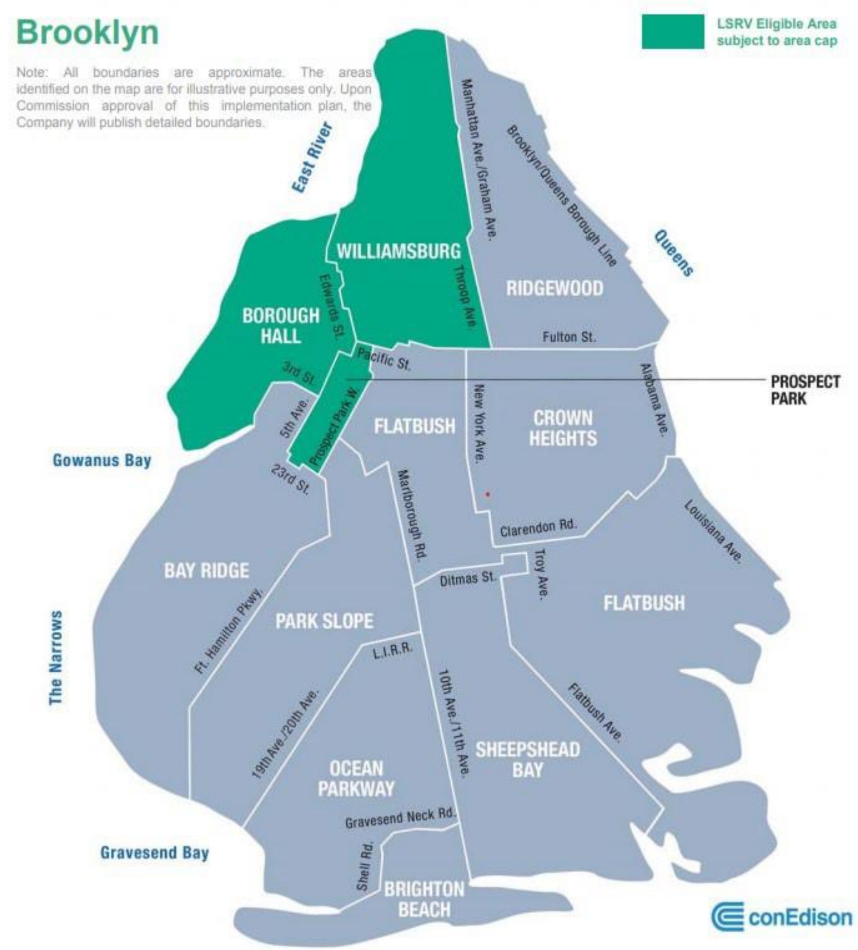
NWA Screening Analysis Tool

- NV Energy performs NWA analysis with their Excel-based NWA Screening Analysis Tool.* The Tool:
  - Captures
    - Information about the traditional solution
    - 15 minute load data for the constrained electric syste facility
  - Provides
    - Suitability/Screening Criteria results
    - Aerial geographic information of the constraint
    - Single lines of the substations involved
    - Outage data (if necessary)
    - Ballpark estimate for NWA DER portfolio
  - Determines the amount of the constraint in future years in MVA, MWh, number of days over established limit, number of hours over the established limit on peak day/selected day of analysis
  - Allows multi-year determinations of estimated amounts of EE, DR, Volt-VAR/CVR, PV, BESS to mitigate constraint
  - Compares ballpark estimates of NWA plus deferred tradition solution PWRR, including estimated benefits from energy supply, generation capacity and energy arbitrage

*In their 2020 DSP filing, the Company noted that they "welcome the opportunity to demonstrate the updated version of this model to interested parties."

DER tariffs

- DER payments based on Value of DER
  - New York Value Stack tariff compensates DER based on location, in addition to energy, capacity, environmental and demand reduction values
  - Locational specific relief value (LSRV) zones are identified by each utility
  - Response to event calls in LSRV zones results in additional DER compensation
  - Net energy metering still an option for onsite residential and commercial DG <750 kW



Source: Con Edison LSRV Zone map

Getting starting with an IDSP proceeding: What other states have done

- ► Develop staff report or white paper outlining DSP needs, goals, and vision
  - Example: Oregon PUC Staff White Paper
- ► Issue surveys or targeted questions to utilities and stakeholders
  - Example utility survey from Minnesota
  - Utility survey, stakeholder survey and follow-up stakeholder questions used in Oregon
  - Initial meetings or workshops
    - Review and discuss surveys and questions
    - Understand current processes, data, systems and filings
- ► Host targeted presentations or trainings for staff and stakeholders
  - Examples: Colorado, Oregon, New Mexico
- ► Require utilities to develop a stakeholder engagement plan prior to technical planning
  - Example: Joint Utilities of NY stakeholder plan and timeline, Oregon Community Engagement Plans
- ► Require utilities to develop initial distribution system plan to report on current system and processes. Example: New York April 20, 2016, order

1. Develop plan and timeline for stakeholder engagement (May 5, 2016)
2. File Initial DSIP addressing current planning, operations, and administration and identifying immediate changes to meet state energy goals (June 30, 2016)
3. File Joint DSIP addressing tools, processes and protocols developed jointly or under shared standards (Nov. 1, 2016)

Questions public utility commissions can ask

- How are grid modernization strategies and distributed energy resources addressed in distribution system plans today? What improvements can be made to better plan for uncertainties and risks in the future?
- How do planned or proposed grid modernization investments contribute to DER integration?
- What DER-related grid constraints are most commonly leading to mitigations or system upgrades? How will smart inverters be used for mitigation?
- What IEEE 1547-2018 implementation processes are needed to unlock the value of smart inverters?
- What steps can be taken today to plan for interoperability between DER owners, utilities and third-party aggregators?
- Are there opportunities to improve the diversity of participating stakeholders, increase data transparency, and clarify the role of stakeholder feedback in distribution system planning processes?
- When evaluating distribution system solutions, are all costs and benefits of the NWAs included in the analysis?
- What data access provisions are needed to provide consumers and third parties with useful customer and system level data?

Resources for more information

U.S. Department of Energy's (DOE) *Modern Distribution Grid*, Vol. IV, 2021

Berkeley Lab's integrated distribution system planning website: https://emp.lbl.gov/projects/integrated-distribution-system-planning

Berkeley Lab's research on time- and locational-sensitive value of DERs

A. Cooke, J. Homer, L. Schwartz, *Distribution System Planning – State Examples by Topic,* Pacific Northwest National Laboratory and Berkeley Lab, 2018

P. De Martini et al., *The Rising Value of Stakeholder Engagement in Today's High-Stakes Power Landscape*, ICF, 2016

P. De Martini et al., *Integrated Resilience Distribution Planning,* PNNL, 2022

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

C. Farley et al., *Advancing Equity in Utility Regulation*, Berkeley Lab, 2021

N. Frick, S. Price, L. Schwartz, N. Hanus and B. Shapiro, *Locational Value of Distributed Energy Resources*, Berkeley Lab, 2021

J. Homer, A. Cooke, L. Schwartz, G. Leventis, F. Flores-Espino and M. Coddington, *State Engagement in Electric Distribution Planning*, Pacific Northwest National Laboratory, Berkeley Lab and National Renewable Energy Laboratory, 2017

J.S. Homer, Y. Tang, J.D. Taft, D. Lew, D. Narang, M. Coddington, M. Ingram, A. Hoke, *Electric Distribution System Planning with DERs — Tools and Methods,* Pacific Northwest National Laboratory and National Renewable Energy Laboratory, 2020

ICF, *Integrated Distribution Planning: Utility Practices in Hosting Capacity Analysis and Locational Value Assessment,* 2018

J. McAdams, *Public Utility Commission Stakeholder Engagement: A Decision making Framework*, NARUC, 2021

Smart Electric Power Alliance, *Integrated Distribution Planning: A Framework for the Future*, 2020

N.L. Seidman, J. Shenot, J. Lazar, *Health Benefits by the Kilowatt-Hour: Using EPA Data to Analyze the Cost-Effectiveness of Efficiency and Renewables,* Regulatory Assistance Project, 2021

Y. Tang, J.S. Homer, T.E. McDermott, M. Coddington, B. Sigrin, B. Mather, *Summary of Electric Distribution System Analyses with a Focus on DERs*, Pacific Northwest National Laboratory and National Renewable Energy Laboratory, 2017

T. Woolf, B. Havumaki, D. Bhandari, M. Whited and L. Schwartz, *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges and Considerations,* Berkeley Lab, 2021

Xcel Energy, *2022-2031 Integrated Distribution Plan*, 2021

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Extra Slides

Procedural elements - Confidentiality

- Confidentiality for security or trade secrets — for example:
  - Level of specificity for hosting capacity maps
  - Peak demand/capacity by feeder
  - Values for reliability metrics
  - Contractual cost terms
  - Bidder responses to NWA RFPs
  - Proprietary model information

Partnership Pilot Program – Overview

GRID MODERNIZATION LABORATORY CONSORTIUM
U.S. Department of Energy

- The pilot is for customer-owned, BTM DER aggregation to test if prescreening aggregators, and the ability to quickly execute contracts with them, will improve and accelerate NWA implementation.
- The pilot will operate for five years. It includes a mid-project review with an opportunity for an off-ramp at the beginning of the third year.
- The CPUC approved the utilities' Partnership Pilot deferral opportunities, budget goals and subscription periods in December 2021 (PG&E, SCE, SDG&E).
  - Evaluation criteria were approved in January 2022. The joint utility advice letter describes the phased approach for evaluating performance for procurement and performance and reliability, off-ramp criteria and evaluation process
- Utilities conduct a prescreening process to identify eligible aggregators for the pilot.
  - Grid needs the aggregator expects to address (e.g., voltage support), DER technologies that the aggregator expects to offer, and documentation of experience and capabilities, financial viability and technical viability
  - As an example, SDG&E's aggregator prescreening application is here.
- Subscription period opened January 2022

Partnership Pilot Program – Contract Process

- The aggregator submits an offer reservation during the subscription period.
- After utility receives it, the aggregator has 15 business days to provide the utility with customer affidavits of interest that include the amount of capacity the aggregator can provide and the amount that already exists. The utility reviews the affidavits to determine whether the aggregator can meet the need.
- When the utility receives offers that meet 90% of the capacity needed to defer the distribution project, the utility contracts with the aggregators. Aggregators have 2 weeks to complete and sign the contract.
- Offers are accepted until the utility has 120% of the capacity needed to defer the distribution project.

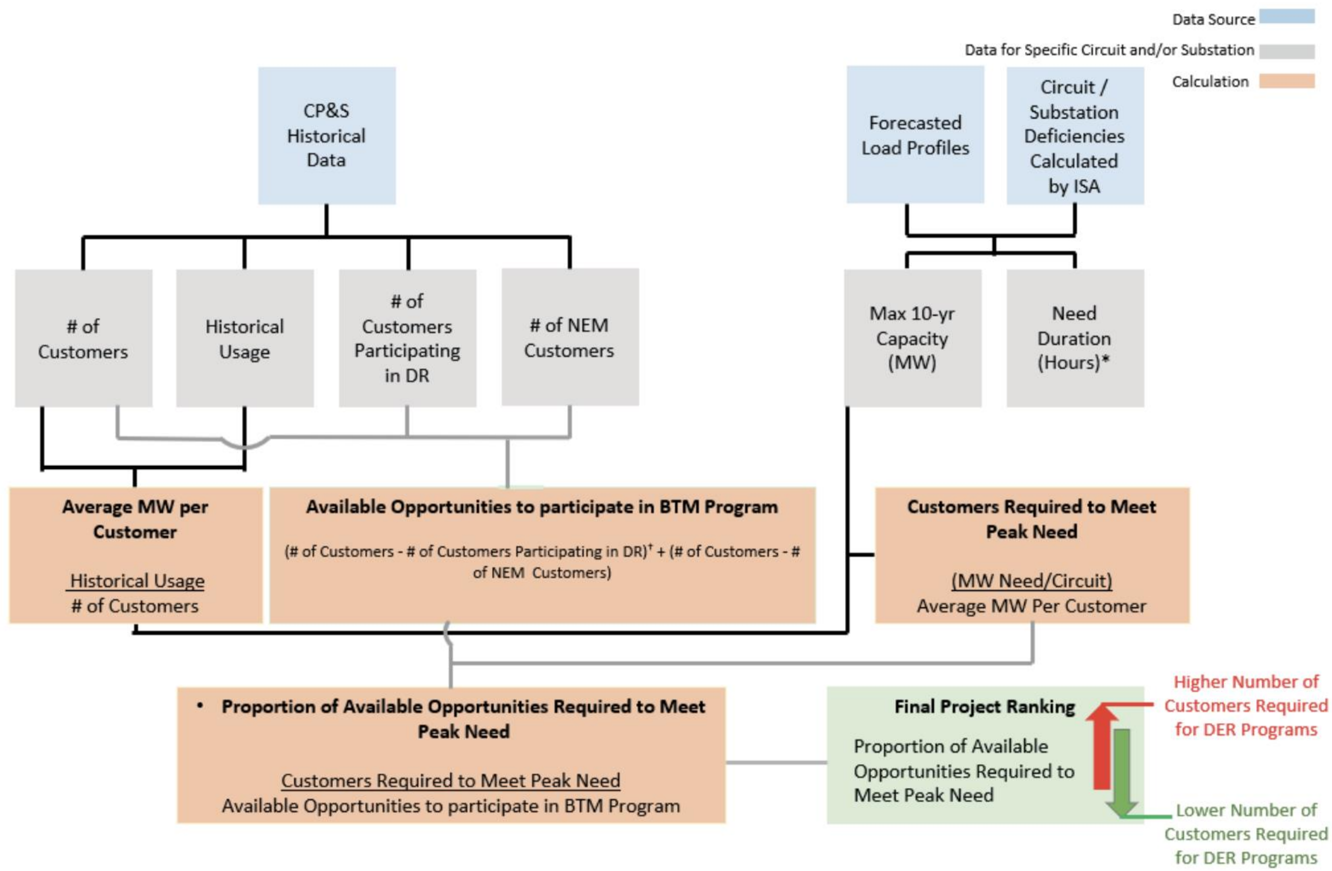
Partnership Pilot – Aggregator Payment

- Aggregator payment is composed of three payment types and is capped at 85% of the one-year deferral value of the distribution project.
  - Deployment payment is provided after the utility has proof that the BTM resources are operational.
  - Reservation and performance payments are made after the utility contracts with aggregators for 100% of the capacity needed to defer the distribution project. These payments are tied to the time when deferral services are needed.

Total Budget		Payments	Share of Total Budget
85% of One-Year Deferral Value		Deployment Payment (not available for existing resources)	20%
		Reservation Payment	30%
		Performance Payment	50%

Example: Southern California Edison Partnership Pilot Program*

- SCE prioritization criteria for the pilot locations:
  - # of customers
  - customer program participation
  - historical usage on each circuit
- SCE priority locations:
  - low participation in a BTM DER program
  - locations requiring fewer customers to be enrolled in DER programs to meet capacity goals
- 3 locations selected:
  - New distribution substation circuit
  - Transformer upgrade
  - Subtransmission line rebuild



Partnership Pilot Program Methodology Flow Chart

*PG&E identified six locations for deferral opportunities. SDG&E determined that it no longer needed the distribution capacity it forecasted for the Partnership Pilot and closed its subscription.

Standard Offer Contract Pilot

- Three-year pilot program that allows providers of front-of-the meter DERs to offer distribution capacity (MW) at a specific price cap to defer a planned utility distribution system investment
- The offer price cap is the value of a one-year deferral of the planned distribution project. Once 90% of the capacity is filled the utilities start the contract process.
- Contract is based on Technology Neutral Pro Forma contract — for example, SDG&E's contract is [here](#).
- The utilities launched their Standard Offer Contract program in September 2021.
  - PG&E identified one deferral opportunity. In [May 2022](#), PG&E requested that the Commission terminate the solicitation because the need increased to 11 MW and a 10-hour performance period (noon to 10 pm).
  - [SDG&E](#) identified one deferral opportunity.
  - SCE selected three deferral opportunities and down-selected to one opportunity after further screening the projects.

Location

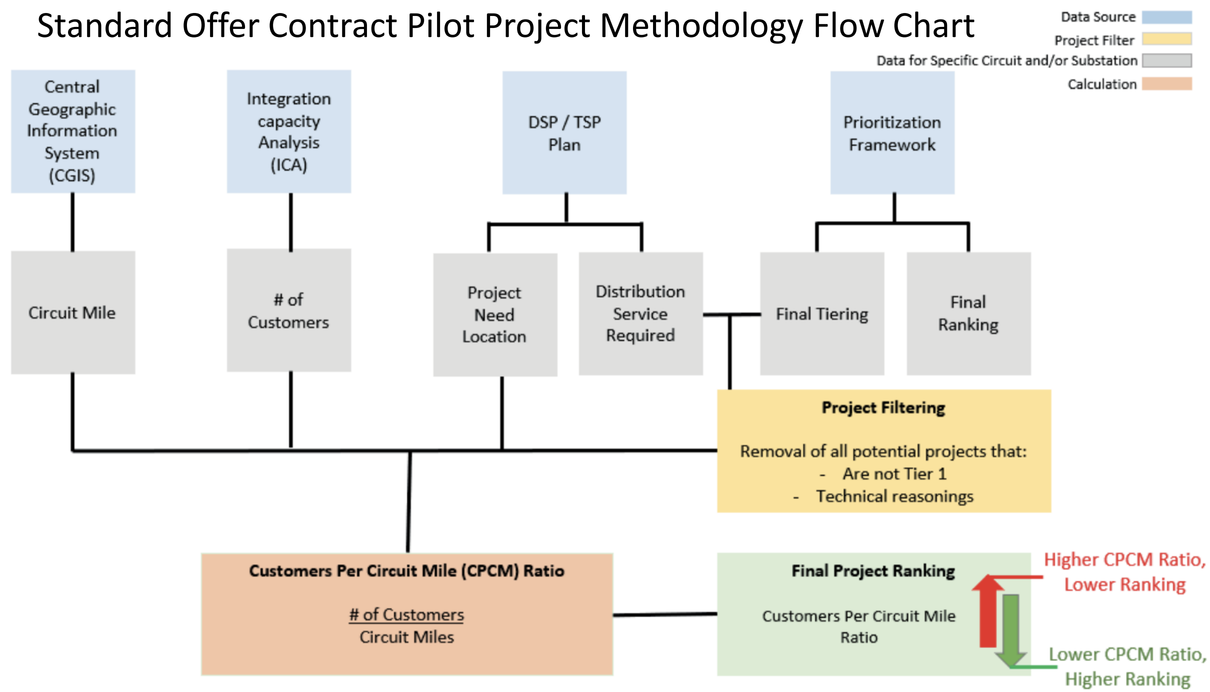
Manteca Bank 6, San Joaquin County

Candidate Deferral	GNA Facility Name	In-Service Date
Vierra Bank 3	Manteca Bank 6	5/1/2024

Example: Southern California Edison Standard Offer Contract Pilot Project

- SCE prioritized projects for the pilot in locations with low customers per circuit mile ratio.

Standard Offer Contract Pilot Project Methodology Flow Chart



Project Description	Tier	Location(s) of Need	Distribution Service Required	Operating Date	Max 10-year Capacity Need (MW)	Max 10-year Duration (hr)	Standard Offer Contract Pilot Project Ranking
New Circuit at Eisenhower	Tier 1	Crossley 33kV	Capacity	6/1/2024	2.9	6	1
New Circuit at El Casco Substation	Tier 1	Jonagold 12kV	Capacity	6/1/2024	0.4	2	2
New Circuit at Elizabeth Lake	Tier 1	Guitar 16kV Oboe 16kV Trumpet 16kV	Capacity (UCT) FLAG	6/1/2024	9.0	11	3

Partnership and SOC Pilot Success Criteria

Success Criteria	Questions to Analyze
Procurement Results	• Were sufficient DERs procured to meet the grid need? If not, why? • Were DERs cost-effective compared to the planned investment? • Of the projects selected for piloting, how many were successfully procured for? What is the percentage?
DER/Aggregator Performance	• Did the DER perform to meet the full grid need? If not, what percent of grid need was met? Why did the DER not perform? • Did the DER perform according to its contractual obligations? How long did it take the DER to respond? • How did the DER perform when called upon day-ahead and day-of? How many dispatch calls were requested and how frequently were they met? • Did technology or DER type affect performance? • Were any projects originally approved to participate ultimately deemed non-incremental? Provide additional detail.
Local Distribution Reliability	• Did the DERs defer the wires investment? Was a contingency plan implemented? • Were other measures taken to mitigate a violation (e.g., switching, temporary generation, etc.)? • Did a violation (e.g., overload, overvoltage, undervoltage, etc.) occur? If so, why? • Were there any service interruptions or was system reliability impacted? • Did the DER impact operational flexibility? If so, how? • Did the DER project impact asset health? If so, how?

- In January 2022, the PUC approved the utilities' evaluation criteria for the Partnership Partner and Standard Offer Contract pilot.
- Two evaluation components
  - Success criteria
  - Performance measures
- Also criteria to terminate the program at a three-year check point

Partnership Pilot and SOC Pilot Performance Measures

- Performance measures are metrics that identify opportunities for improvements in the pilots. The Partnership Pilot has nine performance measures and the SOC pilot has two (see table).
- There are quantitative and qualitative questions for each measure that are identified in the utilities' advice letter.

Performance Measures	Standard Offer Contract Pilot	Partnership Pilot
Phase 1:		
Acceptance Trigger	✓	✓
Procurement Margin		✓
Subscription Period		✓
Tariff Budget		✓
Prescreening		✓
Marketing Partnership		✓
SOC Price Sheet	✓	
Phase 2:		
Customer Attrition and Experience		✓
Ratable Procurement		✓
Tiered Payment Structure		✓