BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters	Application 15-07-002 Application 15-07-003 Application 15-07-005 Application 15-07-006 Application 15-07-007 Application 15-07-008

RESPONSE OF SOLARCITY CORPORATION AND THE CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION TO UTILITIES' DISTRIBUTION RESOURCE PLANS

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Pursuant to the *Administrative Law Judge's Ruling 1) Consolidating Proceedings; 2) Setting Prehearing Conference, and 3) Granting Motion for Extension of Time* issued July 27, 2015, SolarCity Corporation (SolarCity) and the California Solar Energy Industries Association (CALSEIA), collectively "Joint Parties", respectfully submit the following response to the Distribution Resource Plan Applications (DRP Applications) filed by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (hereinafter "utilities") on July 1, 2015. SolarCity has not reviewed and is not addressing the applications filed by PacifiCorp, Liberty Utilities, and Golden State Water Company.

1. Description of SolarCity

SolarCity is California's leading full service solar power provider for homeowners and businesses – a single source for engineering, design, financing, installation, monitoring, and

support. The company provides cost-effective financing that enables customers to eliminate the high upfront costs of deploying solar. SolarCity has more than 6,500 California employees based at more than 35 facilities around the state. SolarCity has provided clean energy services to more than 260,000 customers nationwide.

2. Description of CALSEIA

CALSEIA is a non-profit trade association representing more than 300 member companies and organizations in policy and market development work related to the California solar market. Since the 1970s, CALSEIA has advanced the common interests of the California solar industry, helping make California's solar market the most robust in the United States. CALSEIA's membership is comprised of contractors, manufacturers, distributors, developers, engineers, consultants, researchers and educational organizations.

3. Introduction

The DRP Applications submitted by the utilities represent a significant step forward in fulfilling the broad vision articulated in the Order Instituting Rulemaking August 20, 2014. While Joint Parties believe there are a number of areas where refinement and additional progress can be made, we wish to first and foremost commend the utilities and their staffs for the extensive work and thought that has clearly gone into the DRP Applications. The Joint Parties collectively represent the interests a range of developer that provide a range of distributed energy resources, and therefore have a keen interested in this proceeding, motivated by an appreciation for the tremendous opportunity to leverage distributed energy resources (DERs) to provide a host of services that heretofore have gone largely untapped.

Joint Parties fundamentally believe that DERs have an integral role to play in the energy system. Effectively utilized, DERs will result in the provision of energy services that are cheaper, cleaner and more reliable than reliance on the highly centralized utility infrastructure and control that has characterized the energy system over the past 100 years.

A number of changes are facilitating this transition. For instance, enabling technology costs have declined significantly over the past decade. Coupled with innovative financing solutions and focused and steady policy support, this has greatly expanded access to and deployment of DER technologies. Additionally, and closely related, computing and communications costs have fallen substantially, allowing for more dynamic approaches to system planning and operations that previously would have been either technically impossible to pursue or cost prohibitive.

However accessing the potential embodied by DERs will require substantial reform to existing practices, policies and regulations. The DRP Applications submitted by the utilities represent a vitally important first step, but need to be acknowledged as just that, an initial foray. It is with this perspective in mind that Joint Parties respectfully offer feedback on a number of elements of DRP applications, as further articulated below.

4. Speed of Deployment/Implementation of Capacity Analyses and Demonstration Projects

While Joint Parties do not wish to discount the complexity that may be involved in realizing a number of DRP elements, we encourages accelerated implementation of both the capacity analyses and the demonstration projects, relative to the timeline proposed in the DRP Applications.

a. Integrated Capacity Analysis

Joint Parties note that PG&E was able to complete its analysis down to the node for every circuit within the PG&E system in the nearly five-month timeframe between when the ruling directing the utilities to develop and submit their DRP Applications was issued on February 6, 2015 and the July 1, 2015 submission deadline. This sets a high, but clearly achievable bar that both SCE and SDG&E should seek to match.

b. Demonstration Projects

With regard to the demonstration and pilot projects, the utilities' proposed timelines can be accelerated. The utilities propose a fairly prolonged timeline, which will delay the opportunity to implement lessons learned from these projects in the broader market.

Part of the lag time built into the DRP Applications' demonstration project proposals may stem from the currently vague nature of what the utilities are seeking to achieve through the proposed pilots/demonstrations. While the utilities hew to the four categories identified in the Guidance Ruling,[1] the utilities' descriptions of these projects currently lack the specificity that is necessary to make the pilots sufficiently tangible or actionable. Joint Parties believe additional information regarding the demonstration projects should be provided before the plans are approved. This information should include both the goals of the pilots, as well as a description of how the lessons learned from those pilots, if successful, will be implemented in the broader market.

[1] 1.) Demonstrate the Optimal Locations Benefits Analysis Methodology; 2.) Demonstrate DER Locational Benefits; 3.) Demonstrate Distribution System Operations at High Penetrations of DER; 4.) Demonstrate Distribution Marginal Pricing. *See* Attachment to Assigned Commissioner's Ruling Draft Guidance for Use in Utility AB 327(2013) Section 769 Distribution Resource Plans (Nov. 17, 2014), at pp. 18-19.

It is critically important, whether with regard to demonstration projects or other elements, that a sense of urgency be maintained. Absent such a sense of urgency and proactive identification of intended results, we are concerned that the DRPs as finally adopted will become an interesting, but largely academic exercise.

5. Greater Transparency of Methodology and Assumptions is Needed

Joint Parties also believe there are opportunities to further push the level of transparency, particularly as it relates to the approach and methodologies underlying the integrated capacity analysis and the assessment of locational value. On both fronts, the DRP Applications represent a significant step forward from where things have stood to date. That said, with regard to the integrated capacity analysis, the underlying methodologies and assumptions remain opaque, making it challenging to assess the reasonableness of the resulting information, as well as confounding the ability to compare methodologies across utilities. Publishing sample integrated capacity analysis calculations with all the requisite data needed to perform the analysis would add the transparency sought. Furthermore, the existing integrated capacity analyses do not yet incorporate the full set of DER technologies. For example, load management and energy efficiency are not yet incorporated into the utilities' analyses and should be in future iterations.

Similarly, the locational value methodologies do not currently provide sufficient information for stakeholders to vet the approaches being proposed and understand exactly how the utilities plan on assessing the ability for a given DER to provide a given service. As an initial step, the utilities should publish sample locational value calculations with all the requisite data needed to perform the analysis.

In determining locational values, Joint Parties also encourage the utilities and the Commission to recognize the technical capability of DERs to provide a broad range of services, notwithstanding current regulatory barriers that may impede or limit opportunities today to capture that value. The DRPs ultimately approved by the Commission can and should act as something of a forcing function – identifying technical capability and potential values that then motivate regulatory or policy changes that allow those values to be fully accessed. The DRPs should not be limited to examining only the provision of services that are available to DERs today.

Closely related to the previous point, Joint Parties believe it is important for the utilities to develop a common locational net valuation framework to ensure consistency and equitable treatment of DERs across the IOU Service territories. Based on the conceptual nature of the utilities' current locational net benefits methodology framework, and the significant impact that the methodological details can have both in implementation and cost-effectiveness determinations, Joint Parties believe development of such a common framework is necessary. Joint Parties note that a similar requirement was established in the context of R.10-12-007, the Commission proceeding regarding the establishment of an energy storage procurement target, to ensure that a common protocol was developed to evaluate energy storage and inform storage procurement decisions. This approach was prudent in recognizing the novelty of the technology and the many use cases that energy storage could be reasonably anticipated to address, and helping to provide much needed clarity for the development community. Similar circumstances are evident in the case of DERs and the associated effort to establish a locational net benefits valuation framework. While the framework and underlying protocols may yield different results depending on system configuration and location, methodologies should not be fundamentally

inconsistent across utility service territories (e.g., power quality is considered a benefit in one territory, but not in another).

6. Data Access is Critical Enabler of DRP Vision

Data access is closely tied to the issue of transparency generally. Joint Parties acknowledge the move toward greater data transparency evidenced in the DRP Applications. Both PG&E and SCE have made significant strides in updating their Renewable Auction Mechanism (RAM) maps as part of their respective Integrated Capacity Analyses (ICAs).[2] However, more can be done. For example, PG&E does not allow for batch downloads of data, instead requiring developers to get this data on a one-off or location-specific basis by manually navigating around the RAM interface. Furthermore, only a limited set of the data needed to evaluate IOU analyses or arrive at business and policy insights is provided. These limitations, among others, limit broad analysis of PG&E's integrated capacity analyses to arrive at policy and/or business insights.

As discussed in the attached Integrated Distribution Planning paper developed by SolarCity,[3,] greater access to data plays a key role in informing customer choice and economic development, supporting and driving innovation, supporting the ability to evaluate/audit utility investment plans, and promoting public safety. The types of data that Joint Parties believe the utilities should be required to make available can be grouped into the following five categories:

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[2] *See, e.g.*, PG&E, Solar Photovoltaic (PV) and Renewable Auction Mechanism (RAM) Program Map, http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/index.page; SCE, Renewable Auction Mechanism (RAM), https://sceram.accionpower.com/_sceram_1204/accionhome.asp.

[3] SolarCity, Integrated Distribution Planning (Aug. 2015), at pp. 10-11, *available at* http://www.solarcity.com/sites/default/files/SolarCity%20White%20Paper%20-%20Integrated%20Distribution%20Planning_final.pdf (Attachment A).

Locational Value, Hosting Capacity, Planned Investments, Operational Support, and Market Support. A more detailed discussion of these categories can be found on page 11 of the attached paper.

7. Coordination Across Proceedings

Joint Parties wish to reiterate that it remains critically important for the DRPs to be effectively coordinated with a number of other proceedings at the Commission. Much of the groundbreaking work being pursued in the utilities' plans can and will have significant impacts and implications for a number of active proceedings before the Commission. Perhaps the most obvious of these is the Commission's interconnection proceeding, R.11-09-011, where insights from the integrated capacity analyses may dramatically streamline the Rule 21 process. Additionally, the Integrated Demand Side Resources (IDSR) proceeding, R.14-10-003, which seeks to establish mechanisms that facilitate the procurement of demand side DER resources in recognition of the value that these DERs are found to provide, needs to be informed by the DRPs. Close coordination between these and potentially other proceedings (e.g. Commission's storage proceeding, R.15-03-100, the demand response proceeding, R.13-09-011) will be fundamental to maximize the value all stakeholders derive from this ground-breaking effort.

With regard to the interconnection proceeding, R.11-09-011, the interconnection improvements recommended within the DRP Applications can only be realized if the tools being developed are effectively incorporated into Rule 21. To ensure such an opportunity exists, the scope of R.11-09-011 should be explicitly expanded to include modifications of the Rule 21 process to leverage the tools and capabilities emerging from the DRPs.

8. The DRP Applications Should Lead to Streamlined Interconnection Processes

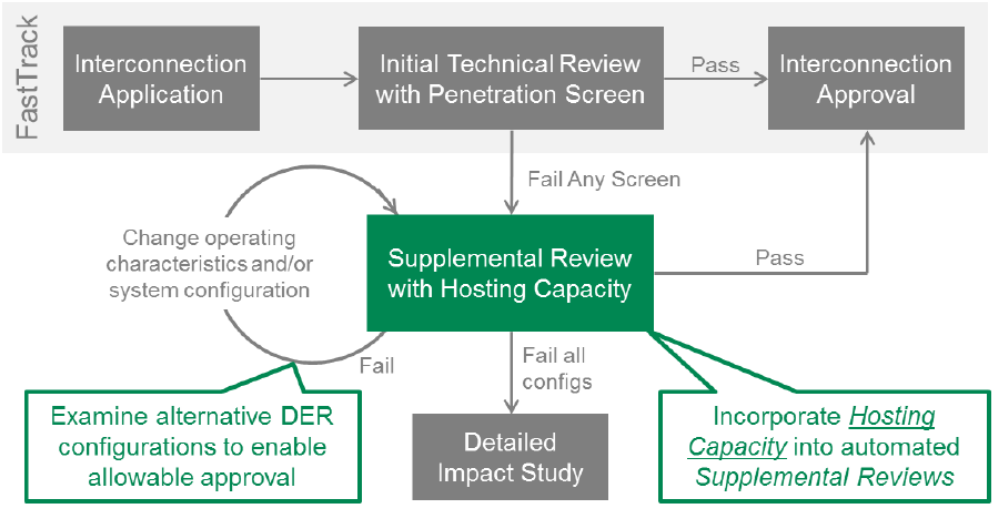
a. Integrated Capacity Analysis (ICA) is Helpful but Requires Explicit Tie Back to Streamlining Interconnection

As mentioned briefly above, the DRPs offer significant potential to enhance the interconnection process. This potential was clearly recognized and called out as one of the specific objectives that President Picker and the Commission sought to realize via the DRP Applications. As stated in President Picker's Guidance Ruling, among the goals of the DRPs is the creation of a distribution grid that is "plug-and-play." The guidance notes that "[o]ne integral step in this process is the need to dramatically streamline and simplify processes for interconnecting to the distribution grid to create a system where high penetrations of DER can be integrated seamlessly."[4]

The integrated capacity analyses undertaken by the utilities offer tremendous potential to streamline the interconnection process by providing a means by which developers would be able to see, well in advance of submitting an interconnection application, whether there is sufficient hosting capacity on the system to accommodate additional DER interconnections. Provided that a DER is seeking interconnection at a place on the distribution system where the additional capacity can be accommodated, knowledge of the available hosting capacity would obviate the need for a project to run through a number of the Rule 21 screens. Overall we find the utilities have made impressive progress in developing the integrated capacity analyses for their respective systems. However, in order to get the most value out of these analyses, they need to be expressly acknowledged and reflected in Rule 21.

[4] Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning (Nov. 17, 2014), at p. 3.

As noted in SolarCity's "Integrated Distribution Planning" report (Attachment A to these comments), the utilities' hosting capacity analyses can serve to significantly streamline the supplemental review process. Below is a process diagram that offers a path for expressly incorporating integrated capacity analyses into Rule 21:



b. Automation is Critical to Further Unlock the Value of the Integrated Capacity Analysis Framework

The opportunity to leverage the utilities' integrated capacity analyses in the interconnection process must be further enabled via automation in order to achieve Commission goals of dramatically streamlining interconnections. Today, the process by which utility engineers review and evaluate the system impacts of a given project on the grid is significantly manual. There are significant opportunities to automate this process. Not only would automation enable a given project to be evaluated more quickly, it also opens up the possibility of conducting more dynamic or iterative analyses that consider different operational characteristics, system configurations or combined DER portfolios. These operational

improvements will, in turn, facilitate more efficient utilization of the distribution system by allowing customers and the utility to consider a range of project designs, technologies and operational requirements.

Automation of the ICAs into the interconnection process will require the development of standardized methodologies and input variables. Joint Parties believe this standardization is an important step that should be undertaken. Successfully implemented, these improvements drive significant progress toward realizing the Commission's vision of a "plug-and-play" grid.

9. Evaluate Allocation of Proposed Integration Expenses

Joint Parties suggest that in evaluating the DRP Applications, the Commission carefully consider whether the IOU-identified distribution system integration costs are business-as-usual investments or are specifically attributable to the deployment of DERs. Joint Parties are concerned that without careful evaluation of some of the expenditures the utilities identify in their plans, some costs may be inappropriately attributed to the integration of DERs. For example, PG&E, SCE and SDG&E each had smart grid deployment plans in place before the DRP Applications were envisioned, each of which included annual status updates and planned investments.[5] These investments were motivated by utility efforts to improve reliability, resiliency, and visibility of their distribution systems. However, many of the items identified for investment in these smart grid deployment plans are also included in the IOU DRP Applications as *Grid Modernization Investments*. For example, SCE's 2014 smart grid deployment update to

[5] *See, e.g.*, PG&E Smart Grid Deployment Plan, 2011-2020 (June 2011), at pp. 37-38, *available at* http://www.pge.com/includes/docs/pdfs/shared/edusafety/electric/SmartGridDeploymentPlan2011_06-30-11.pdf; SDG&E Smart Grid Deployment Plan, 2011 – 2020 (June 2011), at pp. 67-71, *available at* https://www.sdge.com/sites/default/files/documents/smartgriddeploymentplan.pdf; SCE Smart Grid Deployment Plan, (Jul. 2011), at pp. 126-29, *available at* http://docs.cpuc.ca.gov/PublishedDocs/EFILE/A/138423.PDF.

the CPUC identifies the deployment of "remote control switches within its distribution system" as a part of its *Circuit Automation* project.[6] Yet SCE also includes investment into "automated switches with enhanced telemetry" as part of its DRP *Grid Modernization Investments*.[7] These investments appear to be the same, yet are justified via different rationales. The emergence of DERs does not change the underlying and pre-existing impetus for the utilities to pursue these investments, and therefore it is more appropriate to consider these to be business-as-usual investments rather than expenses resulting from the anticipated deployment of DERs. In short, a more thorough discussion of cost allocation related to IOU investments into DER integration activities is merited.

10. Process

Joint Parties have a number of additional process-related suggestions to help ensure the DRP Applications are well-vetted by the stakeholder community and to support course adjustments as needed on an ongoing basis.

First, regarding costs, although in some instances the utilities provide some cost-related information, many of the IOU costs anticipated to carry out their DRP plans are currently unknown. While some of these costs and their recovery will likely be proposed via general rate case filings, Joint Parties believe there may be merit in having the utilities clearly and separately identify those costs that are a direct result of DRP implementation. Stakeholders should have a clear opportunity to review and comment on these costs and Joint Parties request that the Commission ensure such an opportunity is provided.

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[6] SCE's (U 338-E) Annual Report on The Status of Smart Grid Investments (Oct. 1, 2014), at p. 21.
[7] SCE DRP Application, (Jul. 1, 2015), at p. 214.

Additionally, once the DRPs are adopted, the Commission should establish a recurring forum to provide an opportunity for stakeholders to provide periodic feedback to the utilities and to the Commission regarding a host of issues related to DRP implementation, including DRP investment plans, progress on data access issues, development of a common locational value framework, efficacy of the ICA, etc. These forums could take the form of topic-specific working groups that meet on a quarterly basis, with representation from interested stakeholders as well as the Commission. Similar periodic stakeholder forums have been established in the context of the California Solar Initiative as well as in the Commission's efforts around demand response to positive effect.[8]

11. Conclusion

The instant filings by the utilities represent a significant amount of innovative and positive work that moves the state closer to fully integrating and taking advantage of the potential of DERs to be integrated into and play a more substantial role in the distribution system. While there are clearly areas where additional refinement and effort is necessary, Joint Parties again wish to commend the utilities as well as other stakeholders for the considerable progress to date. We look forward to continuing to engage with all stakeholders and the Commission in this important initiative.

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[8] *See, e.g.*, CPUC, California Solar Initiative (CSI) Program Forum, http://www.cpuc.ca.gov/PUC/energy/Solar/forum.htm; CPUC, California Solar Initiative Workshops, http://www.cpuc.ca.gov/PUC/energy/Solar/workshops.htm; CPUC, Demand Response Workshops, http://www.cpuc.ca.gov/PUC/energy/Demand+Response/DemandResponseWorkshops.htm.

Respectfully submitted,

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California Solar Energy Industries Association

August 31, 2015

ATTACHMENT A

Integrated Distribution Planning paper developed by SolarCity

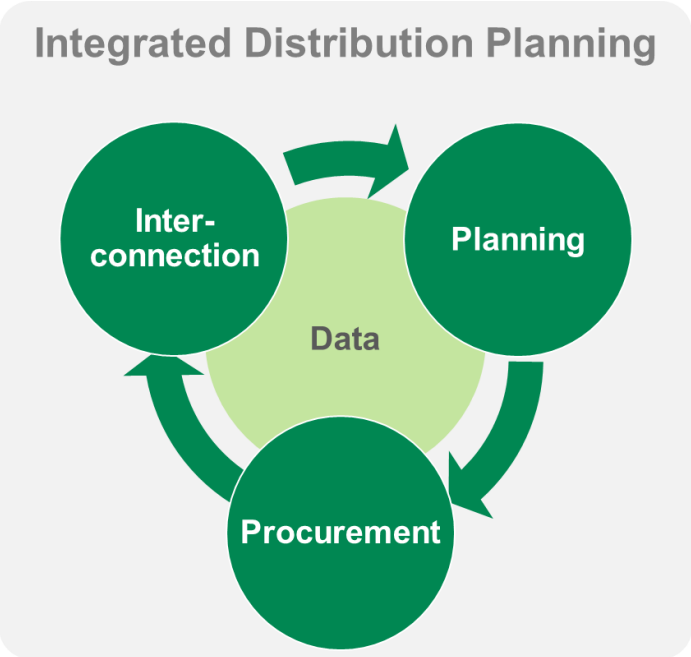
SolarCity

Grid Engineering

Integrated Distribution Planning

A holistic approach to meeting grid needs and expanding customer choice by unlocking the benefits of distributed energy resources

White Paper



Key takeaways

Takeaway 1
Integrated Distribution Planning is a holistic approach to meeting distribution needs and expanding customer choice by modernizing utility *interconnection*, *planning*, *procurement*, and *data* sharing processes.

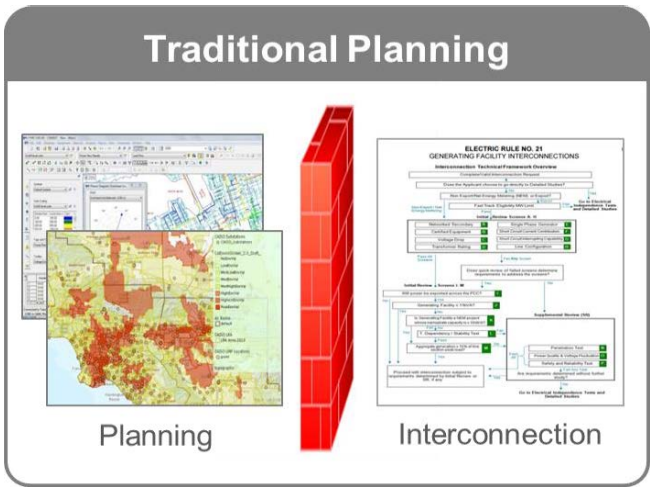
Takeaway 2
Hosting Capacity analyses should be incorporated into the interconnection of distributed energy resources to streamline and eventually automate interconnection

Takeaway 3
Adopting *Distribution Loading Order* policies will encourage the procurement of cost effective distributed energy resources before conventional distribution equipment

Background

Designing the electrical grid for the 21st century is one of today's most important and exciting challenges. In the face of evolving electricity needs and an aging electrical grid that relies on centralized and polluting sources of power, it is imperative to transition to a grid that actively leverages the wave of renewable distributed energy resources proliferating across the industry. Distributed energy resources offer tremendous benefits to this new grid by actively engaging customers in their energy management, increasing the use of clean renewable energy, improving grid resiliency, and making the grid more affordable by reducing system costs. Designing a grid that fully harnesses these assets is a key undertaking for all industry stakeholders, including utilities, regulators, legislatures, and DER developers.

Current efforts to utilize DERs to support the broader electric system, however, are hampered by the systemic failure of the industry to integrate DERs into distribution planning efforts. As the figure to the right depicts, traditional distribution planning is highly siloed and planning efforts are considered independently of interconnection efforts. To fully leverage DERs to benefit the grid, utility interconnection, planning, procurement, and data sharing efforts must be modernized.



August 2015

Challenge: Existing utility interconnection, planning, procurement, and data sharing processes do not leverage DERs to benefit the grid and enable customer choice.
Solution: Modernize distribution interconnection, planning, procurement and data sharing processes by adopting a holistic *Integration Distribution Planning* framework.

Integrated Distribution Planning is a holistic approach to meeting distribution needs and expanding customer choice by unlocking the benefits of distributed energy resources. The approach expedites DER interconnections, integrates DERs into grid planning, utilizes DER portfolios as procurement resources, and ensures broad access to critical data. Ultimately, the approach reduces overall system costs while increasing customer engagement. In the following paper, we introduce four components of *Integrated Distribution Planning* (*Interconnection*, *Planning*, *Procurement* and *Data*) and offer recommendations for how to seamlessly integrate distributed energy resources into the modernized process.

We offer this paper as an initial vision for a holistic process to leverage DERs to benefit the grid. However, there are many details to develop in order to realize this vision. SolarCity continues to work on developing these details for the concepts proposed in this paper, and we welcome collaboration with industry thought leaders to do so. Our ultimate goal is to help provide the concrete recommendations and justification needed by regulators, legislatures, utilities, DER providers, and industry stakeholders to create the impetus for change needed to transition to a cleaner, more affordable and resilient grid.

Interconnection

The utility DER interconnection process consists of rules and requirements that govern the connection and operation of distributed energy resources within a utility's electric grid.

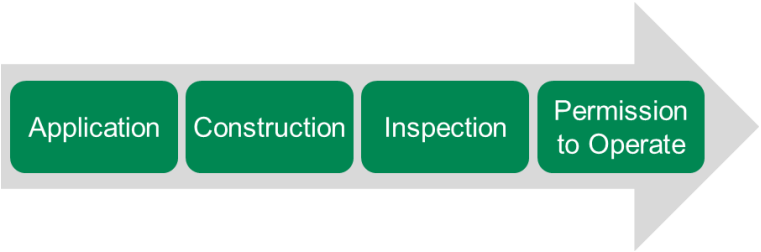
Today's utility interconnection processes often follow idiosyncratic rules and timelines that differ from utility to utility, suffer from a general lack of process automation, are subject to burdensome technical reviews or arbitrary requirements that slow or prevent DER interconnections. In many regions, the current interconnection process is not keeping pace with the local DER growth, threatening an inefficient backlog that will burden utilities until a more streamlined approach is adopted.[1] As a result, customers who want to invest in energy infrastructure to play an active role in managing their energy usage are increasingly unable to expediently and cost effectively to do so.

Some utilities have begun reforming their practices to create a more efficient interconnection process, with several existing "best practices" serving as a guide for the industry. Overall process improvements have been limited in scope, however, and the pace of change is measured. A more comprehensive set of enhancements is needed to streamline the interconnection process, eliminate unnecessary costs, and expand allowable interconnections.

Challenge: Existing utility interconnection processes can be avoidably slow, include unwarranted costs, and unnecessarily limit DER interconnections.
Solution: Streamline the DER interconnection process, eliminate unwarranted costs, and expand allowable interconnection approvals.

Streamline the Process

There are four critical steps in interconnecting a system to the grid: application, construction, inspection, and permission to operate (PTO). Utilities control the timeline for critical elements of this process. While many states establish timeline requirements for the initial utility application review, these targets frequently are not met. For example, a study by the National Renewable Energy Laboratory (NREL) found that most utilities routinely exceed time limits for application review by 37-58%.[1] Similarly, EQ Research published findings showing that PTO timelines increased 68% from 2013 to 2014.[2]



Several states have embarked on initiatives to update aspects of the interconnection process. While positive, these developments often focus on a few low-hanging fruit, such as the creation of an online portal to submit and track application review progress, rather than a more comprehensive set of improvements. Streamlining the entire interconnection process should be considered by utility engineering organizations and regulators, especially when many of these improvements have been individually implemented by various utilities across the country. A comprehensive set of best practices and recommendations are presented in the following table.

Interconnection Process Improvement Best Practices

Category	Best Practices & Recommendations
Documentation	• Accept single line diagrams in applications in lieu of three line diagrams[3] • Allow project drawings to be approved by licensed contractors without Professional Engineer stamps[4] • Document utility inspection procedures and include time limits[5] • Follow a PTO closeout checklist template for sequence of operations and witness test procedures[6] • Maintain an online list of certified equipment by part number and settings approved for interconnection.[7]
Visibility	• Make pre-application reports available online on the utility website[8] • Enter all application correspondence by project into a password-protected online portal, starting with the initial application and including regular status updates • Publish impact studies on the utility website • Create and publish interconnection maps online for identification of favorable interconnection sites[9]
Simplicity	• Do not require a signed construction contract with an interconnection application[10] • Allow construction to proceed at third party's risk with no required utility conditional approval prior to start of construction[11] • Eliminate multiple-part applications in favor of a single, comprehensive application
Cost Certainty and Cost Minimization	• Budget impact study costs by man-hours at an hourly rate, with outsourcing costs stated as a line item[12] • Do not charge ordinary service and maintenance fees for utility-owned equipment required for interconnection[13] • Do not charge interconnection application fees for Net Metered projects[14] • Establish a process through which interconnection upgrades and costs are identified prior to interconnection application submission • Publish standard upgrade unit costs to allow better planning and budgeting by third parties[15]
Cost Allocation	• Allocate upgrade costs equitably to all beneficiaries (i.e. both DER owners and non-DER customers)[16] • Consider the clustering of projects within a common geography when possible[17]
Standards	• Set the standardized interconnection project size limits to no lower than 5 MW • Perform simplified/fast-tracked review for verified non-export and smart export projects • Do not allow the presence of an existing DER service on a parcel of land to prevent the installation of new DER service for virtual net metered projects[18]
Mitigation Equipment	• Ensure utilities have sufficient mitigation equipment on hand to meet interconnection volume • Increase the flexibility of mitigation requirements where cost effective alternatives exist • Allow meter socket adaptors or alternate supply-side taps to facilitate customer-sided DER installations
Review & Reform	• Institute a fully online application process rather than written applications • Prohibit paper forms or hard copy mailings in application process[19] • Accept electronic signatures on all required documents[20] • Accept electronic payment • Allow certified third party contractors to perform metering work related to interconnection (e.g. meter pulls or replacements)[21]
Incentives & Penalties	• Create penalties and incentives governed by regulatory agencies to encourage compliance with legislated time limits[22] • Conduct annual audits with independent reviewers to determine utility compliance with timelines.[23] • Publish results of annual processing timelines • Require utility-developed plan if backlog is over acceptable threshold

Eliminate Unwarranted Costs

Many utilities worried about real and perceived impacts of DERs are specifying equipment upgrades to mitigate their concerns. However, these mitigations are often based on outdated standards or made without regard to the advanced capabilities of modern DERs, which can often preempt the concerns underlying the proposed mitigations. The result is that utilities are requiring overly conservative and often unnecessary upgrades as a condition of interconnection.

Sourced from SolarCity's interconnection efforts across the United States, we identify below the most common utility mitigation requirements. Based on the latest body of technical research and standards available, as well as our own research into many of these topics in collaboration with utilities and national laboratories[24], we offer cost effective, safe and reliable alternatives to these upgrades when applicable, with the goal of reducing overall system costs to all customers.

Typical Utility Mitigations and Recommended Approach

Mitigation	Utility Rationale	Recommendation
Protection Equipment - SCCR	DERs may cause desensitization of relays, miscoordination of protective devices, and/or surpassing of interrupting rating of line clearing element (e.g. breaker, fuse, etc.).	When short circuit contribution ratio (SCCR) of all generating facilities downstream of a protective device is less than 10%, DER customers **should not pay** for upgrades to protective equipment because DERs do not impact relay desensitization, miscoordination, or interrupting ability.[25,26,27] When SCCR exceeds the conservative 10% limit *and* a protection review indicates technical concerns, settings changes to protective devices should be investigated before proposing equipment upgrades.
Reclose Blocking	Islanding may occur if generation and load are balanced. If an island persists longer than reclose delay, equipment may be damaged.	Reclose blocking due to unintentional islanding concerns **should not be required** because reclose blocking is not intended to prevent an island and standard inverter anti-islanding features are effective at preventing unintended islanding.[25,28,29] If specified by the utility as a redundant measure, reclose blocking should be considered part of normal utility business and should not delay interconnection.
Direct Transfer Trip (DTT)	Unintentional islanding may occur if generation and load are balanced at an automatic sectionalizing device.	DTT installation due to unintentional islanding concerns **should not be required** because standard inverter anti-islanding technology is effective at preventing unintended islanding.[25,28,29] If specified as a redundant measure, DTT should be considered part of normal utility business and should not delay interconnection.
Reconductor	Aggregate DERs exceed the thermal capacity of conductor and/or causes voltage issues.	Customer payment **can be justified** if new DERs exceed conductor thermal rating. However, if multiple and/or future customers will benefit from the upgrade, equitable cost allocation across all beneficiaries should occur.
Transformer replacement	Aggregate DERs exceed the transformer thermal capacity, requiring replacement.	Customer payment **can be justified** if new DERs are the sole reason for the transformer upgrade. However, if multiple and/or future customers will benefit from the transformer upgrade, equitable cost allocation should occur. Additionally, utilize smart inverter functionality before replacing transformer.
Grounding transformer	Transient overvoltage conditions caused by DERs during unbalanced fault conditions may damage equipment.	DER customers **should not pay** for installation of grounding transformers because inverter-based ground fault overvoltage magnitudes and durations are within safe limits with Yg-Yg distribution transformers.[30] Additionally, with Yg-Yg distribution transformers, any overvoltage is not a result of neutral shift overvoltage and therefore would not be mitigated by grounding measures.[31]
SCADA Recloser	Utility requires remote control and monitoring of DERs for feeder safety and reliability.	DER customers **should not pay** for dedicated SCADA reclosers because reclosers are a redundant and/or overly expensive solution for the desired use. Less expensive alternatives exist for monitoring and remotely disconnecting DERs. Reclosers used for anti-islanding and/or crew safety are redundant to existing standards.[32,33]
Monitoring equipment	Increased visibility is needed to observe DERs' impact on loading and power quality.	DER customers **should not pay** for utility monitoring equipment because grid monitoring is part of normal utility business operations, regardless of the existence of DERs, and benefits all customers.
Voltage Equipment – Variability	High DER penetration and the resulting intermittency could cause line voltage violations including both steady-state voltage and voltage flicker.	DER customers **should not pay** for utility voltage regulating equipment installations when inverters can eliminate need for incremental equipment via advanced features including ramp rate control, dynamic power factor settings, and/or utility Volt VAR Optimization control.[34] Furthermore, voltage variations due to distributed PV have been shown to match the existing voltage variations from normal load fluctuations.[35]
Voltage Equipment – Reverse Flow	DERs may cause reverse power flow on unidirectional voltage regulating equipment or require replacement of a fixed capacitor with a switched bank	• *Regulators* – If equipment upgrade is justified, DER customers **should not pay entire upgrade costs** as the upgrades benefit the entire distribution system. • *Capacitor banks* – customers **should not pay** to upgrade fixed capacitor banks to switched capacitor banks when smart inverters can provide the same power quality management capabilities as switched capacitor banks.

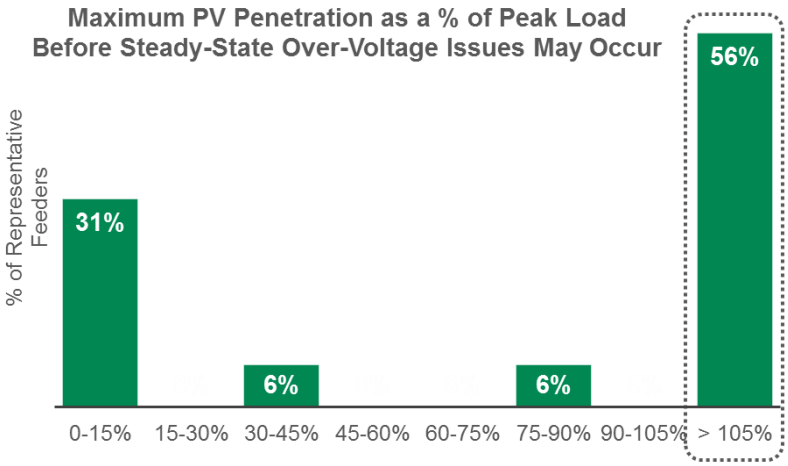
Expand Allowable Approvals

Low DER Penetration Levels

At low DER penetration levels, utilities should enable fast-tracked interconnection of most DER applications while adopting a streamlined *Supplemental Review* process that utilizes simplified, shorthand impact calculations to increase allowable interconnection approvals without the need to implement more complex impact analyses.

At the heart of traditional DER interconnection processes are technical screening rules that determine the eligibility of a proposed DER project to interconnect. These screening rules are often universally applied to all circuits (e.g. interconnection allowed when DERs are less than 15% of peak load), even though circuits are unique. These existing screening rules are often overly conservative for most circuits given the most recent technical research. For example, the Hawaiian Electric Company imposed a moratorium on solar PV in Hawaii from September 2013 to February 2015. The widespread halting of solar PV interconnections within the state was the result of the utility's concerns over the impact of high penetration PV – concerns that were later dispelled after technical study.[36]

Applying a 'one-size-fits-all' or 'rule of thumb' screening process inherently limits the amount of DERs that can be safely interconnected on the majority of circuits. The figure on the right depicts NREL findings that identify the maximum amount of PV penetration that can be accommodated without steady state voltage violations by various distribution circuits. As shown, 56% of circuits can accommodate over 105% PV penetration as a percentage of peak load.[37] This data highlights that circuits are unique, and that even in low penetration scenarios universal screens are ineffective at identifying technical concerns.



At low DER penetration levels, utilities should utilize simplified, shorthand impact calculations in lieu of universal screens to increase allowable interconnections without the effort required to implement more complex impact analyses. The Electric Power Research Institute (EPRI) proposes a set of shorthand calculations as an alternative to universal screens, which can serve as a model for utilities.[38]

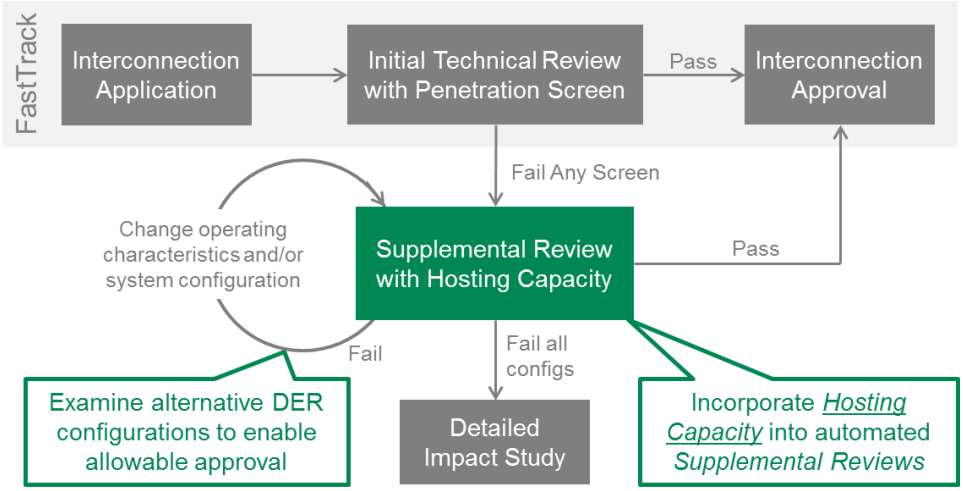
High DER Penetration Levels

At high DER penetration levels, utilities should incorporate automated DER *Hosting Capacity* analyses into the interconnection review process to increase allowable interconnections while decreasing the application review timeline.[39]

While the shorthand modifications to screening rules discussed above can be an effective approach to streamlining interconnections at low DER penetration levels, this approach quickly breaks down as DER penetrations increase and more circuits hit the limits prescribed by this simplified method. Therefore, shorthand screens should be phased out in favor of detailed, location-specific impact analyses that determine the amount of DERs that can be accommodated on a specific circuit. Such analyses are called DER *Hosting Capacity* or *Integrated Capacity* analyses.

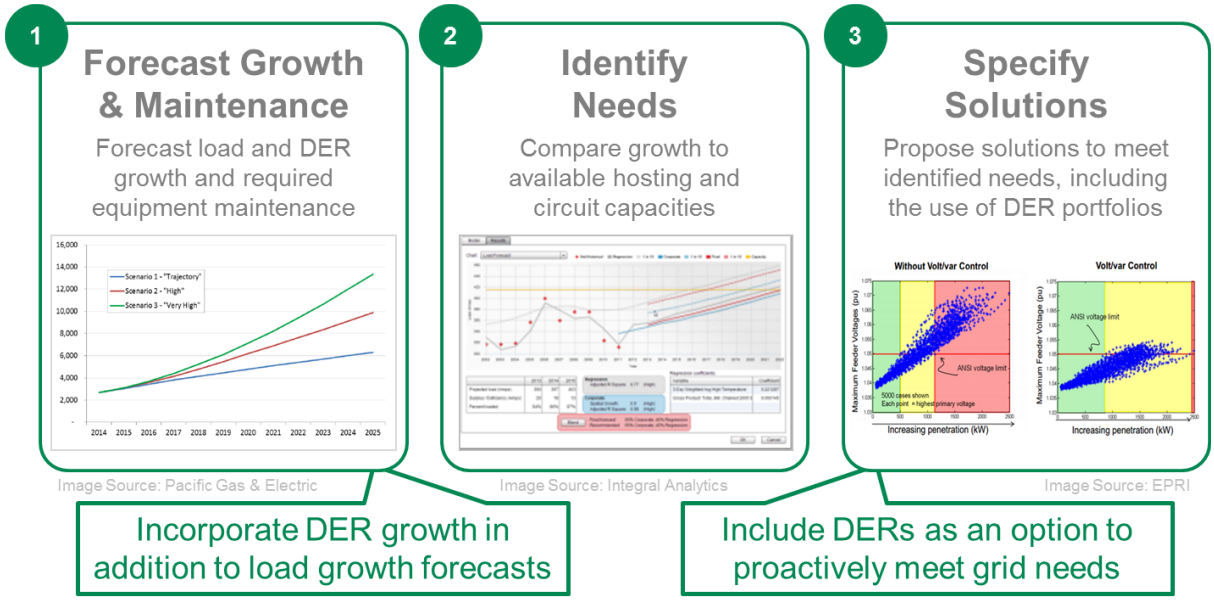
A circuit's *Hosting Capacity* is the amount of DERs that can be safely and reliably interconnected – or *hosted* – on any given feeder based on its specific characteristics. A hosting capacity analysis evaluates a variety of circuit operational criteria – including voltage, loading, protection, power quality and control – under the presence of a specific level of DER penetration – and identifies the limiting factor for DER interconnections. Hosting capacity analyses provide an indication of how many DERs can be accommodated given existing utility and customer-owned equipment on a circuit. The result is a more tailored, circuit-specific screening tool for the DER interconnection process: proposed projects that fall under the available hosting capacity can be quickly processed through interconnection approval, while projects that exceed the hosting capacity require further engineering analysis.

A process flow for incorporating hosting capacity into the interconnection process is depicted below. Note that if an interconnection application fails the *Initial Technical Review*, the application goes through a *Supplemental Review* where hosting capacity analyses are used to evaluate approval. In order to facilitate efficient application processing, this Supplemental Review should be streamlined by incorporating automated hosting capacity analyses. Furthermore, if an application fails the Supplemental Review, then the utility should work with the customer to iterate DER system design configurations and/or operating characteristics to examine whether an alternate design would pass supplemental review.



Planning

While *Interconnection* focuses on allowing increased penetrations of DERs on the system, a modernized *Distribution Planning* process focuses on meeting distribution needs and unlocking the benefits of DERs. As depicted in the figure below, the traditional distribution planning process involves three steps: forecasting growth, identifying grid needs, and specifying solutions. This framework remains suitable for distribution planning in the presence of high DER penetrations, but it must be modernized to actively leverage the value of DERs.



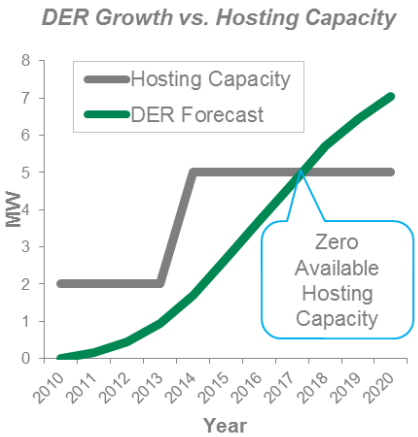
Challenge: Current utility planning process does not leverage DERs to provide grid services, lower systems costs, and increase grid resiliency.
Solution: Modernize utility distribution planning to leverage DERs.

Forecast Growth & Equipment Maintenance

All utility planning efforts begin with identifying the grid and customer needs that must be met, as well as required maintenance to existing equipment. Traditionally, utilities have established grid needs focused on meeting peak demand and power quality requirements as a result of customer load growth. However, in a high-penetration DER grid, customer choice related to deploying DERs must also be accommodated into grid needs. As such, utilities will need to become much more proficient at forecasting customer DER growth than they are today. The required proficiency is achievable since at its core, forecasting DER growth requires a similar skillset to forecasting load growth. Both forecasts are contingent upon a variety of demographic, economic, technological, location-specific, and historical trends that are probabilistic in nature. Although utilities are currently only beginning to forecast DER growth, they can leverage modern forecasting techniques and computing power to analyze increasing amounts of data to become as adept at forecasting DER growth as load growth.

Identify Needs

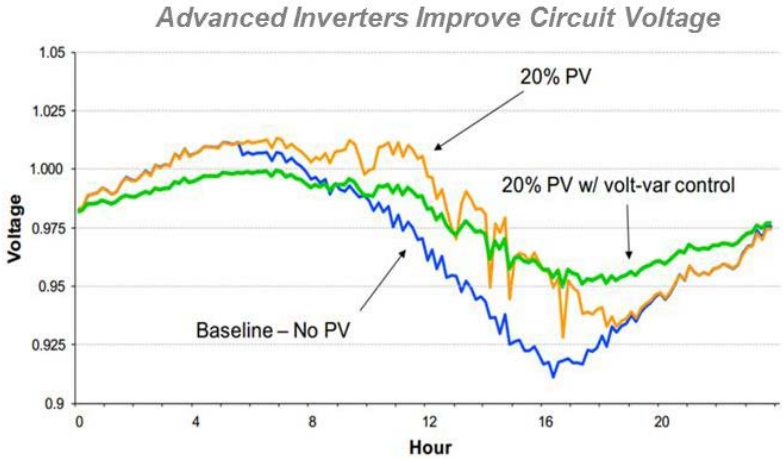
After forecasting customer DER adoption and load growth for a defined area, utilities will need to compare the forecasted growth to the distribution grid's available capacity. This effort mirrors current utility efforts of comparing load growth to available circuit capacity, except that now utilities must also compare DER growth to DER hosting capacity. Such comparisons will enable utilities to proactively identify when circuits may reach their current threshold for accommodating additional DERs. Using this information, utilities can prioritize which circuits to proactively evaluate for increasing available circuit and/or hosting capacity. As discussed below, there are a host of options available to increase circuit and hosting capacities at no or minimal cost. See figure on right for an illustrated comparison of DER growth to available hosting capacity, indicating when zero available hosting capacity will occur for the specified location.



Specify Solutions

Once grid needs are identified, planners specify available solutions to meet those needs. Solutions can include tweaks to existing utility equipment settings, changes to customer and utility equipment operating requirements, use of existing DERs to offset circuit or hosting capacity needs, changes to technology and/or software systems, and the procurement of incremental assets. Procurement efforts and mechanisms utilizing DERs are outlined in the *Procurement* section below.

Alternatives to procured investments are often available at low or no cost, increasingly so with the increased deployments of DERs. Advanced inverters can be utilized to provide voltage and reactive power support, customer batteries can provide peak capacity support, load shifting can absorb over generation, and tweaks to distribution equipment configurations can enable higher levels of reverse power flow, among others. For example, the IEEE figure[40] below illustrates the benefit that advanced inverters can offer for the dynamic support of circuit voltage.



Procurement

Today's status quo planning model does not consider *Procurement* of third-party solutions to meet the distribution needs. Utilities instead rely on 'steel-in-the-ground' infrastructure funded by regulatory rate case proceedings, with utilities self-supplying 100% of their distribution system solutions. Under this model, regulators rely on the expertise of distribution planners to deploy capital that meets customer demand in the most cost-effective way possible.

Given recent technological advancements and growing customer DER adoption, the self-supply distribution procurement model must evolve to grant utilities the flexibility to consider the full scope of solutions available to meet grid needs, including third-party DER portfolios. While this evolution requires modernizing an entrenched distribution planning process to utilize the *Procurement* tools described below, the end result will be more cost-effective solutions at planners' disposal.

> *Challenge*: Current utility distribution procurement processes does not adequately leverage DERs to provide grid services, lower systems costs, and increase grid resiliency.
> *Solution*: Modernize distribution procurement process to evaluate and deploy DERs to meet grid needs.

Evaluate Options

The first stage of utility *Procurement* is the evaluation of options available to meet the identified need. Traditional distribution planning limits the scope of available procurement options to conventional solutions: namely self-supplied, utility-owned distribution equipment such as transformers, capacitor banks, reconductored wires, and other capital equipment. In a future with high levels of DERs connected to the grid, distribution planners must be willing and able to consider the full range of solutions available. If this opportunity is not realized, planners risk making, and regulators risk authorizing, redundant investments that increase system costs for ratepayers.

In order to bridge this disconnect, we propose a distribution-level policy concept to encourage the adoption of DER portfolio solutions: *Distribution Loading Order*. The *Distribution Loading Order* borrows an existing concept from some states' regulated utility energy procurement, which prioritizes procurement of renewable energy ahead of fossil fuel-based sources. For instance, in 2003 California's principal energy agencies established a "loading order" for energy efficiency, demand response, renewables and distributed generation with the intent of operating the electricity system in the best, long-term interest of consumers, ratepayers and taxpayers.[41] Similarly, introducing a *Distribution Loading Order* provides a framework for procuring distribution solutions based on a specified prioritization that is consistent with longer term policy objectives to support cleaner and more resilient electric systems.

In the context of distribution needs, the *Distribution Loading Order* prioritizes the utilization of individual DERs or portfolios of DERs over traditional utility infrastructure, when such portfolios are cost-effective and able to meet grid needs.

Distribution Loading Order: Procurement Solutions

Proposed Distribution Loading Order	Selection of Resource Examples
1. **Distributed Energy Resources** (DERs)	Energy efficiency, controllable loads/demand response, renewable generation, advanced inverters, energy storage, electric vehicles
2. **Conventional Distribution Infrastructure**	Transformers, reconductoring, capacitors, voltage regulators, sectionalizers

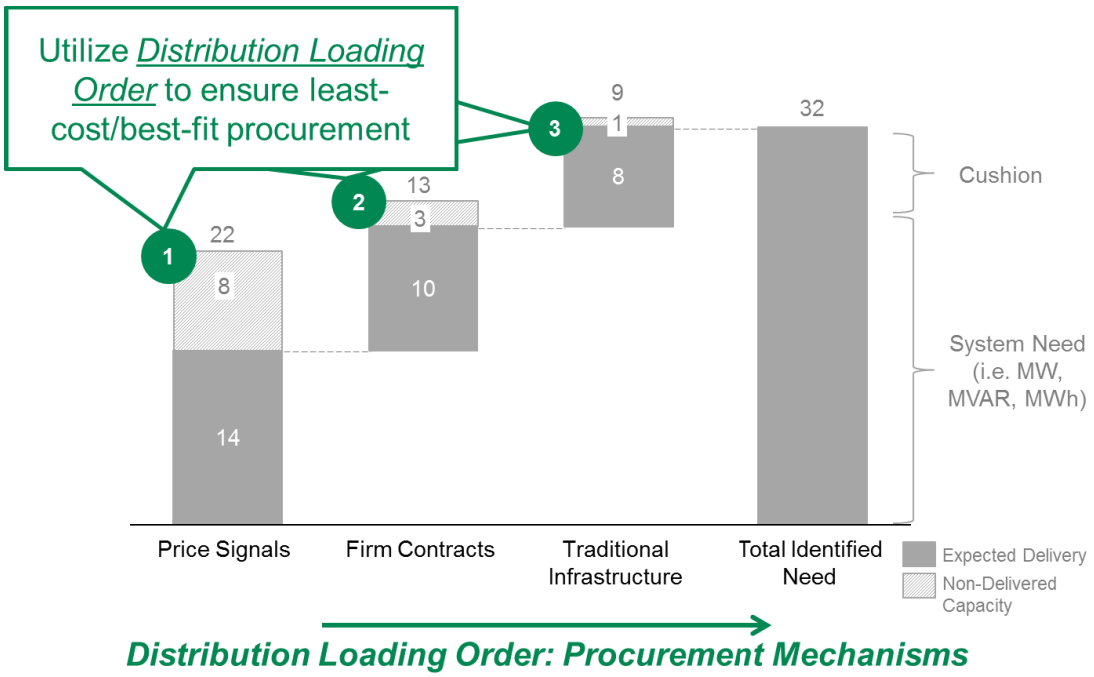
While the Distribution Loading Order provides an explicit hierarchy to evaluate and prioritize resources, it is equally important that the loading order include new *procurement mechanisms* given the scarcity of existing competitive procurement at the distribution level. These new procurement mechanisms must accompany a Distribution Loading Order to ensure that planners have channels to fairly consider alternative solutions against conventional utility investments. In practice, a planner would meet a specified grid need by executing a standard procurement process, considering DER solutions ahead of traditional utility infrastructure. The distribution procurement mechanisms proposed in the table below provide a guide for how and in what prioritized order utilities should evaluate grid solutions to comply with the Distribution Loading Order.

Distribution Loading Order: Procurement Mechanisms

Rank Order	Procurement Mechanism	Description	Selection of Practical Examples
1	**Price Signals** (DERs)	DER portfolios that voluntarily respond to price signals sent from the utility that incent the desired behavior to meet grid needs.	• Voluntary Critical Peak Power / TOU Pricing • Voluntary Distributed Marginal Pricing (DMP) • Voluntary Voltage Support Pricing
2	**Firm Contracts** (DERs)	DER portfolios that are contractually obligated to deliver grid services based on contracted prices.	• Week-Ahead Reactive Power Payments • 1-10 year ahead availability contracts for peak substation real power capacity
3	**Traditional Utility Infrastructure**	Traditional utility infrastructure self-supplied through General Rate Case capital budgets.	• Utility investment in Substation transformer • Utility investment in feeder reconducturing

As with *integrated resource planning* utilized at the wholesale level, *asset availability* must be considered when deploying DERs to meet grid needs. While DERs – or any grid resource – voluntarily responding to price signals may respond less consistently than an asset under direct utility control, utilities can quantify the expected availability of such assets. While perhaps a new concept in the distribution context, methodologies exist for assessing availability-based resources, such as *Effective Load Carrying Capability* (ELCC) and other probabilistic methods currently used in demand response programs.

The figure below provides a conceptual illustration of how availability methodologies could be used to probabilistically discount the different types of distribution products. In this example, the utility has identified a total grid need of 32 MW of, say, capacity. To meet this need, the utility first procures capacity through price signals where it obtains 22MW of nameplate capacity, but availability of only 14MW. The utility continues to utilize the remaining procurement mechanisms until its need is met. Note that the availability of resources responding voluntarily to *price signals* is discounted by a larger ratio than *firm contracts* and *traditional infrastructure*.



Several economic and policy principles provide the underlying rationale for the recommended procurement approach:

1. Since DERs are often paid for fully or partially by customers, DER portfolios will increasingly offer grid services to distribution and bulk system operators at a lower cost than conventional investments. Thus, utilizing price signals to leverage embedded DERs holds the potential to reduce the overall cost to ratepayers to meet grid needs.
2. Leveraging customer DERs in favor of building new utility infrastructure is desirable when technically and economically feasible because it encourages further customer engagement in their energy management, utilizes assets voluntarily chosen by customers, and enhances grid resiliency by supporting further adoption of DERs.
3. In the absence of a *Distribution Loading Order*, utilities will overlook the potential for DERs to meet grid needs. This

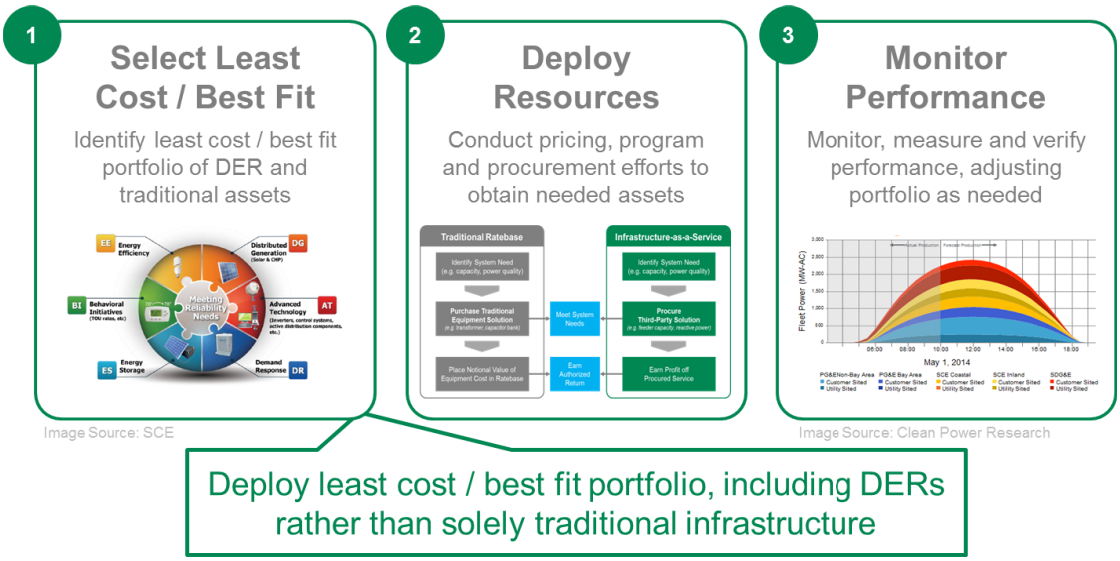
structural bias is highly likely due to organizational inertia and, more importantly, the explicit financial incentive that utilities face to invest capital in traditional infrastructure that generates regulated shareholder returns.

4. Since the Distribution Loading Order retains planners' flexibility to deploy conventional infrastructure after evaluating DERs, utilities can always deploy traditional infrastructure if needed to ensure system reliability.

While conventional utility distribution equipment offers familiar functionality to distribution operators, these assets can be expensive, bulky, long-lived, and inflexible. By prioritizing the consideration of DER portfolios to meet distribution needs via a *Distribution Loading Order,* utilities will maximize the value of advanced DERs on the grid to the benefit of customers.

Deploy Portfolios

After evaluating the potential options to meet grid needs, utilities select and deploy the solution that is least cost / best fit, consistent with standard utility operating practice and the Distribution Loading Order. The least cost / best fit portfolio is likely to be a combination of product categories, including *price signals*, *firm contracts* and *traditional infrastructure* assets. Once the portfolio is selected, utilities must deploy the resources through a variety of mechanisms including voluntary enrollment in customer pricing/tariffs, customer deployment programs, solicitations (i.e. request for proposals), price-clearing markets, and utility infrastructure deployment. Each of these assets are likely to have a different deployment timeline, so utilities and regulators will need to revisit planning timelines to ensure the longest lead time assets and programs are procured and deployed first with a sufficient buffer in place to install traditional infrastructure if some procured assets do not materialize. After deployment, utilities will need to monitor performance to verify that DERs are delivering the grid services as required. The figure below depicts the stages of deploying portfolios to meet grid needs.



Data Transparency & Access

With the ever increasing deployment of DERs, grid operational and planning data is critical to continued market innovation. Currently, utilities hold the vast majority of grid data and little of it is available to the industry.

Data sharing is critical to grid modernization as it informs customer choice, spurs economic development, supports innovation, enables credible auditing of utility investment plans, supports public safety, and eventually will foster a robust transactive energy marketplace. Conversely, solely publishing outcomes of utility analyses rather than sharing the underlying data does not enable sufficient industry stakeholder engagement or innovation. Data access and transparency is the foundation of current ratepayer advocacy efforts and should be extended into *Integrated Distribution Planning*.

> *Challenge*: Utility data critical for driving innovation is not readily accessible by broader industry.
> *Solution*: Utilities must commit to data transparency and access to enable industry innovation.

Data Transparency

There are a number of foundational reasons to actively promote grid planning and operational data sharing:

- *Data sharing informs customer choice and economic development*
    - Should customers pursue projects on a specific feeder?
    - Do DER providers have enough business runway to retain local employees?
    - Should DER providers open a warehouse/office in a specific geographic area?
- *Data sharing supports industry innovation*
    - Data sharing unlocks third party engagement, dramatically increasing pace of innovation
    - Third parties have knowledge to engage in and improve distribution planning, particularly in new skillsets that are not traditional utility strengths (e.g. data analytics, software/product development)
- *Data sharing enables credible auditing of utility investment plans*
    - DER providers can suggest alternative means to meet distribution system procurement needs
    - Solely publishing outcomes of analyses (i.e. hosting capacity analyses) does not enable sufficient auditing of utility methodology/decision making
    - Data access is the foundation of ratepayer advocacy and should extend into distribution planning
- *Data sharing supports public safety*
    - Transparent data increases visibility into potential public safety concerns

Five categories of data should be shared by utilities and DER providers. Additional categories may be required in the future.

- *Locational Value* – Locational value data identifies the costs and benefits of locating DERs in a specific location. Currently, this data is not made available, which impedes efforts to locate DERs where most beneficial to the grid.
- *Hosting Capacity* – Due to the critical nature of hosting capacity information for every DER provider and customer, the underlying data to calculate hosting capacities should be made available. Simply publishing hosting capacity values themselves is inadequate, and limits the innovation that third parties can provide.
- *Planning & Investments* – Utility planning and investment data by circuit is critical to understanding which investments could be offset by DER portfolios. Planning and investment data is typically shared via utility regulatory rate making proceedings, and this data should be shared at increasingly granular circuit-levels.
- *Operational Support* – As utilities make more use of price and dispatch signals to support grid needs, access to real-time and historical operational data will be critical to enabling and evaluating performance. The more real-time data is shared, the more valuable grid services DER portfolios will be able to provide.
- *Market Support* – As transactive markets begin to take shape, sufficient pricing data and event statistics should be shared in order to support well-functioning markets.

Data Access

In addition to identifying which utility data must be shared to support the market, the mechanism for sharing that data is critical to market animation. Online access to bulk, downloadable data is critical to spur market innovation. Simply making data viewable but not downloadable is not sufficient, as third parties require the ability to perform analyses on the underlying data to develop insights.

Downloadable, aggregated, anonymous distribution data through online portal

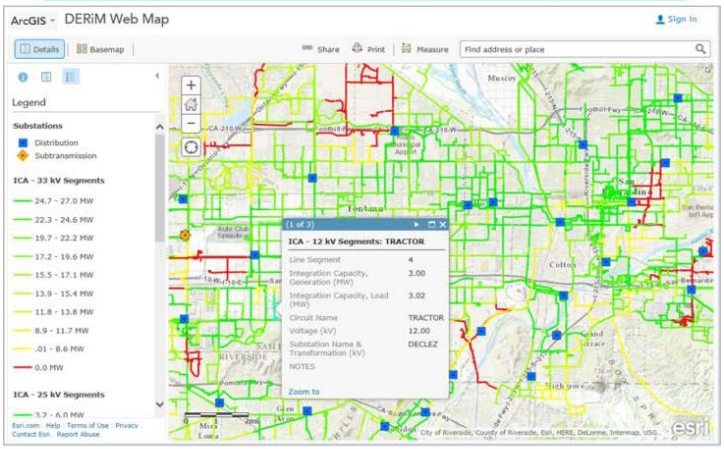


Image Source: Southern California Edison

Data access best practices are emerging as a result of utility innovation. Recent enhancements to the Renewable Auction Mechanism (RAM) maps from Southern California Edison (see figure on right) and Pacific Gas & Electric offer examples of online platforms that third parties can use to access utility data.[42] While improvements remain to enable streamlined access to data from these platforms (i.e. downloadable data rather than just viewable data), these maps serve as innovative examples of the data sharing platform.

Conclusion

Electricity demands across the world are growing, yet our outdated electrical grids rely on centralized, finite sources of power. Transitioning the grid to one that leverages the wave of distributed energy resources proliferating across the industry is imperative to meet this need. Distributed energy resources offer tremendous benefits in the form of lower system costs, improved grid resiliency, and increased use of clean energy. DERs empower customers to become active participants in their energy management and fuel job creation as we collectively modernize the grid for the 21st century.

Evolving utility interconnection and planning processes into a holistic and proactive *Integrated Distribution Planning* process is essential to unlocking the promise of distributed energy resources. We offer this paper as an initial vision for a holistic process to leverage DERs to benefit the grid. However, there are many details to develop in order to realize this vision. SolarCity continues to work on developing these details for the concepts proposed in this paper, and we welcome collaboration with industry thought leaders to do so. Our ultimate goal is to help provide the concrete recommendations and justification needed by regulators, legislatures, utilities, DER providers, and industry stakeholders to create the impetus for change needed to transition to a cleaner, more affordable and resilient grid.

For more information, please visit us at solarcity.com/gridx or contact us at gridx@solarcity.com

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[10] Interconnection standard process for Southern California Edison
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