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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)

ASSIGNED COMMISSIONER'S RULING ON GUIDANCE FOR PUBLIC UTILITIES CODE SECTION 769 – DISTRIBUTION RESOURCE PLANNING

On August 14, 2014, the Commission issued Rulemaking (R.) 14-08-013 to establish policies, procedures, and rules to guide California investor-owned electric utilities (IOUs) in developing their Distribution Resources Plan (DRP) Proposals, which they are required by Pub. Util. Code § 769 to file by July 1, 2015. This Rulemaking also intends to evaluate the IOUs existing and future electric distribution infrastructure and planning procedures with respect to incorporating Distributed Energy Resources (DERs) into the planning and operations of their electric distribution systems.

Subsequent to the Rulemaking, the Energy Division conducted a workshop on September 17, 2014, to provide a forum for the IOUs and stakeholders to explore issues raised by § 769. The workshop also previewed positions subsequently raised in comments on the Rulemaking on September 22 and Replies on October 6, 2014.

This Assigned Commissioner Ruling (ACR) sets out final guidance for content and structure of the DRPs that will be filed by July 1, 2015. The DRPs filed should be consistent with each other in structure and content so they may be more easily compared and analyzed. While each IOU's application will be expected to provide information and proposals that best reflect its own circumstances and operational needs, it is in the public interest to ensure some level of standardization in approach and methodology for achieving the goals of § 769.

1. A New Framework for Distribution Planning

Since 2001, the Public Utilities Code has provided that "[e]ach electrical corporation, as part of its distribution planning process, shall consider nonutility owned distributed energy resources as a possible alternative to investments in its distribution system in order to ensure reliable electric service at the lowest possible cost." In addition, between 2001 and the present, the Commission has developed policies that engaged and promoted ever greater quantities of DERs located within the IOUs' distribution systems. In recognition that traditional distribution system planning is limited in its ability to support State policies on DERs and emerging technologies, the Legislature passed Assembly Bill (AB) 327 in 2013.

Section 769 (established by AB 327) requires IOUs to submit DRPs that recognize, among other things, the need for investment to integrate cost-effective DERs and for actively identifying barriers to the deployment of DERs such as safety standards related to technology or operation of the distribution circuit. Notably, the Commission is authorized to modify and approve a Utility's DRP "as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources." The goal of § 769 must be understood in the context of both the five explicit requirements that must be addressed in the DRPs, as well as a broader context of California's energy and climate goals. Consistent with AB 32 and Executive Order S-21-09, in order to deliver benefits, major energy policies initiatives should support the achievement of 2020 and 2050 greenhouse gas (GHG) reduction targets. The DRPs are no different. This also recognizes the fact that the underlying rationale for promoting increased deployment of the DERs specified by statute is that they have a critical role to play in meeting California's policy of significantly reducing GHG emissions from the State's electricity and transportation systems.

Additionally, because they provide a platform for future investments in energy delivery infrastructure, primarily but not limited to the electric distribution networks owned and operated by IOUs, these DRPs should also reflect these parallel goals:

1) to modernize the electric distribution system to accommodate two-way flows of energy and energy services throughout the IOUs' networks;
2) to enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost efficient manner; and
3) to animate opportunities for DERs to realize benefits through the provision of grid services.

An inevitable consequence of these rapidly evolving changes to utility distribution will be the need to add new infrastructure, enhance existing networks and adopt new analytical tools to allow consumers to be active managers of their electricity consumption through the adoption of DERs; the goal being to create a distribution grid that is "plug-and-play" for DERs. One 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.

Additionally, as recognized by § 769, the Commission, the IOUs, consumers and new service providers, must work cooperatively to revise existing incentives and tariffs to promote DER in locations that will provide the greatest net benefits to the grid. These benefits include enhanced reliability of delivery and the opportunity to introduce innovation – whether driven by the IOUs or by non-traditional parties – into the utility of the future.

A significant component of the net benefit calculation will be whether deeper penetration of DER in a particular location or on a specific feeder will be able to provide an alternative to the most costly upgrades of distribution (or eventually transmission) facilities that might otherwise be necessary to meet load. The deferral or avoidance of network upgrades may, in fact, offset much of the expected costs of accommodating new customer-side resources. So the DRPs must recognize a balance between promoting grid modernization technologies and minimizing the total expected investment in this system while allowing for deeper penetration of DER throughout utility grids. This is, indeed, a daunting challenge, but one that the IOUs and the Commission must face head on in this proceeding. This locational optimization aspect of § 769 represents an especially difficult challenge to those engaged in this Rulemaking.

Finally, although § 769 appears to call for a one-time exercise in this new method of Distribution Planning, there appears to be general agreement that this should really be an on-going, cyclical process that will repeat over time to incorporate how technologies and market policies are evolving and to take advantage of lessons learned in previous cycles. In addition, it is important that these DRPs reflect not only the prospect of an iterative process going forward, but also recognize and map how each IOU's Smart Grid Deployment Plan will support the DRP initiative.

For this reason, one of the most important recommendations of this guidance document is for the Commission and IOUs to adopt a biennial DRP filing cycle as part of the ratification of the Utility DRP Applications. Each iteration of the process will move California further down a path toward deeper penetration of DER, more effective analysis of where DER provides the most value to customers and to the electric distribution system, and a greater understanding of the policy framework that is necessary to achieve these goals.

Some Parties would like this proceeding, and the DRPs, to serve as platforms for reinventing the existing utility distribution services model – perhaps along the lines being investigated in New York State's "Reforming the Energy Vision" (REV) process. That is not the focus of this proceeding. As the Order Instituting Rulemaking in this proceeding stated, "The goal of these plans is to begin the process of moving the IOUs towards a more full integration of DERs into their distribution system planning, operations and investment."

Given the significant change this will represent to traditional distribution planning processes – which are mainly focused on meeting expected load growth and potential peak consumption without much regard to customer-side interactions – even this relatively narrow focus may be considered ground-breaking.

While it is logical to conclude that effective integration of DERs at the level envisioned by this Rulemaking may well trigger necessary changes to business models and utility service platforms, that is a longer term prospect, and beyond the scope of this current proceeding and the attached Guidance document (appended to tis Ruling). Nonetheless, there may be opportunities in the context of this proceeding to begin exploring ideas for the future – this can only benefit the Commission, IOUs and Parties in understanding the long-term implications of the actions that we begin today.

This is why the Commission has recognized and aligned this phase of the proceeding with the *More Than Smart* initiative (described in more detail below). It is the intent of the attached Guidance document to incorporate the most relevant outcomes from that initiative while focusing the first proposed DRPs on meeting the directives of § 769. It is my intent that in 2-3 years, we will move beyond questions like how to quantify and operationalize the locational value of DERs, towards a focus on the relationship between the IOUs, consumers, third-party DERs providers and the California Independent System Operator (CAISO). What we learn from this round of DRPs will help frame these discussions and provide a critical foundation to evaluate questions related to future business models and market designs.

An addendum to the structural guidance section of the attachment provides a proposed schedule for phasing future planning developments and activities over a longer term time horizon.

2. The More Than Smart Vision

Over the course of the last two years, the More Than Smart initiative has sought to bring together leading thinkers at the Grid Edge to develop a framework for integrating DERs into the fabric of distribution planning and operations. More Than Smart started as a collaboration between Caltech's Resnick Institute, the Greentech Leadership Group and the Governor's Office of Planning and Research to organize a set of conferences to discuss how to institute the changes necessary to enable a DER friendly grid. As the More Than Smart initiative progressed, it coalesced around the development of a white paper, *More Than Smart: A Framework to Make the Distribution Grid More Open, Efficient* *and Resilient*, that was appended to the OIR for this proceeding. This paper presented a set of four key principles around distribution planning, design build, operations and integrating DER into operations that it posits are critical to creating a more open, efficient and resilient grid.

- **Distribution planning should start with a comprehensive, scenario driven, multi stakeholder planning process that standardizes data and methodologies to address locational benefits and costs of distributed resources**. Distribution planning is becoming more complex. An integrated planning and analysis framework is needed to properly identify opportunities to maximize locational benefits and minimize incremental costs of distributed resources. This is enabled by a standardized set of analytical models and techniques based on a combination of utility grid operational data and DER market development information to achieve repeatable and comparable results.
- **California's distribution system planning, design and investments should move towards an open, flexible, and node-friendly network system (rather than a centralized, linear, closed one) that enables seamless DER integration.** California's vision for significant DER contribution to resource adequacy and safe, reliable operation of the grid requires a move to a network system. The evolution to an open platform will involve foundational investments in information, communication and operational systems not seen in existing utility smart grid plans. These investments should be based on solid architectural grid principles while ensuring the timing and pace align with customer needs and policy objectives. In the future, the state should strive toward converging electric utility designs with other distribution systems for gas, water and other services.
- **California's electric distribution system operators (DSO) should have an expanded role in electric system**

operations (with CAISO) by acting as a technology-neutral marketplace coordinator and situational awareness and operational information exchange facilitator while avoiding any operational conflicts of interest. Today, bulk power systems and distribution systems are largely operated independently. DSO's can help play an integrating role with CAISO. California is already at the point at which integrated and coordinated operations based on better situational information is essential. This integration requires both an expansion of the minimal functions of utility distribution operations and clear delineation of roles and responsibilities between the CAISO and utility distribution system operators. Finally, as with transmission, distribution operations will need standards of conduct to ensure neutral operational coordination.

- **Flexible DER can provide value today to optimize markets, grid operations and investments. California should expedite DER participation in wholesale markets and resource adequacy, unbundle distribution grid operations services, create a transparent process to monetize DER services and reduce unnecessary barriers for DER integration.** Flexible DER can provide a wide range of value across the bulk power and distribution systems. The issue is not if or when, but rather how do we enable integration of flexible DER into these systems. This will be enabled by the expansion of CAISO services and new distribution operational services. As such, new capabilities and performance criteria should be identified as part of the distribution planning process. These new services should be coordinated with existing programs knowing some existing demand response programs may be surpassed in their relevance and value in the context of AB 327 objectives. Finally, barriers to broad participation involving complex and expensive measurement and verification schemes and related settlement processes should be simplified for DER.

The More Than Smart paper, and party comments thereof, helped to build the foundation for this guidance. The More Than Smart initiative did not stop at the development of the white paper. It has subsequently continued to convene interested stakeholders to discuss many of the key questions that are raised in this guidance document. In this way, the More Than Smart initiative has served as a way for a diverse group of interested parties, from the Utilities to DER technologist to ratepayer advocates, to engage in open discussion of complex technical questions, which can then be brought forward to this proceeding.

3. Description of Purpose and Scope of the Guidance

The guidance document attached to this ACR is intended to describe the structure and contents of the DRPs the IOUs are required to file in July 2015, pursuant to § 769. This guidance defines certain terms that are used in § 769, as they are to be applied in the plans. Finally, the guidance describes what is in the scope of the plans, what is being handled in other proceedings and potential overlap and necessary coordination, and existing statutes, standards and requirements that will also govern the plans.

4. Jurisdictional Scope

The scope of this guidance encompasses the "distribution system," which is the portion of the electric supply system that operates at voltages lower than the transmission level on the "customer side" of the distribution substation. Although "distributed energy resources" are not specified in § 769 in terms of interconnection voltage level or maximum nameplate capacity, it is assumed in this proceeding that DER will mostly be interconnected at the distribution voltage levels and at sizes of 20 megawatts (MW) or less.

5. Identification of Related Proceedings and Processes that Overlap R.14-08-013

These are several Commission proceedings in which subjects such as interconnection, rates, incentives and goals for certain classes of DER are already under active consideration. The following list includes most of the active proceedings that have been identified that directly relate to areas that are potentially encompassed by the DRPs. This is not a complete list, but is meant as a placeholder as more areas of overlap are identified.

- Alternative Fueled Vehicles (R.13-11-007);
- Demand Response (R.13-09-011);
- Distributed Generation (R.12-11-005);
- Energy Efficiency (R.13-11-005);
- Energy Storage (R.10-12-007, now closed, but which is expected to have a successor rulemaking in 2015-16);
- Integrated Demand-Side Management (R.14-10-003);
- Net Energy Metering Successor Tariff (R.14-07-002);
- Residential Rate Reform (R.12-06-013);
- Smart Grid (R.08-12-009, pending closure);
- Water-Energy Nexus (R.13-12-011);
- Energy Upgrade California Marketing Education & Outreach (currently without an open proceeding).
- Rule 21 Interconnection (R.11-09-011);
- Renewable Portfolio Standard (R.11-05-005); and
- Long-Term Procurement Planning (R.13-12-010).

This Rulemaking, and the DRPs that will be filed in 2015, do not intend to supersede policy determinations or programmatic decisions that rightly fall to the above proceedings. For example, this Rulemaking should not establish new procurement targets for the various DERs identified by § 769 , but if new information about resource need is developed in this proceeding, the IOUs should make every effort to align this information with what is being determined in the relevant policy proceeding.

Similarly, the DRPs should not be the forum to adopt new tariffs that are instrumental for certain technologies, a task that is rightly relegated to the appropriate rulemaking. For example, while this Rulemaking might recommend that a locational benefit component would be valuable addition to Net Energy Metering, the development of such a tariff is best conducted in the Net Energy Metering Successor Tariff rulemaking.

In the long run, it may be expected that the changes to infrastructure investment and DER penetration that are enabled via the DRP process will inevitably have impact on Long-Term Planning and Procurement activities currently conducted by the Commission, as well as other procurement mechanisms, ranging from Renewable Portfolio Standard solicitations to Energy Storage procurements. For this reason, it is essential that Commission Staff and the Utilities make every effort to maintain close coordination among all of these proceedings in order to prevent duplication of effort, conflicting priorities and wasted economic investments.

To the extent that activities in the DRP can or should impact the existing proceedings, the DRPs should identify areas in which the Commission needs to incorporate findings or activities from or into these related proceedings.

6. Identification of other relevant statutory requirements that DRPs must address

Besides the underlying Legislative mandates that guide Commission responsibilities to ensure safe, reliable and affordable electric services, and the terms of § 769 (and other provisions of AB 327 that impact distributed generation and rates), there is always a potential that new Legislative measures will be enacted into law that could impact DER policies.

One such bill, SB 1414 (Wolk, 2014), has been recently signed into law to amend Pub. Util. Code § 380 and 380.5 to establish policies to incorporate demand response (DR) within the Resource Adequacy requirements that IOUs are required meet. While at this point it is uncertain how this new law would impact Utility or third-party DR programs, the Utilities in their planning efforts must assess and accommodate this new directive.

Just as with current regulatory initiatives, the DRPs must explicitly recognize any existing or new Legislative mandates which may have a direct bearing on DER deployment.

7. Coordination among Utilities, State Agencies and ISO

Going forward, it is critical that DRP activities be coordinated among the three IOUs, the CAISO, and the California Energy Commission (CEC), as well as the Commission. Increasing penetrations of DER connected at the distribution level pose operational, planning and policy development challenges for the ISO and the CEC that must be accounted for in processes that are outside the scope of the DRP. Coordination with the Transmission Planning Process, the Long-Term Procurement Planning Process and the Integrated Energy Policy Report is essential, both as the DRPs are developed, and as they are executed.

There is a tension between the desires of DER technology providers and enablers to fully participate in energy service markets beyond provision of energy to residential and commercial customers or utilities, and limits on the current structures to allow full participation in such markets (or those that can be developed in the future). This Rulemaking, and the DRPs that result, cannot resolve these issues at this time, but may represent the first steps toward creation of a new industry model for full and interactive integration of DERs at a level previously unimagined. Coordination among agencies and industry players will be key to success.

8. Commission Process

The general schedule of this proceeding was outlined in R.14-08-013 to include the issuance of a draft Guidance document in December 2014, followed by this ACR which sets final Guidance for the IOU DRP filings, all of which culminates in the IOUs filing their DRPs by July 1, 2015. While this process proceeds, there will be a period of four or five months in which it may be useful for Commission Staff to actively engage parties and non-Party industry participants in further refining aspects of Distribution Plans, market forecasts, locational benefits analysis, cost-effectiveness methodologies, or the bigger questions of how these may influence regulatory policies and Utility business structures in the future.

9. Categorization of Utility DRP Filings

Given that the DRPs may necessitate cost recovery to be fully implemented, the Utilities are directed to file the DRPs as Applications which the Commission may then consolidate with this Rulemaking into a single proceeding.

10. Applicability to Small and Multi-Jurisdictional Utilities

In comments to the OIR for this proceeding, the California Association of Small and Multi-Jurisdictional Utilities (CASMU) requested that they be allowed to submit more simplified versions of the DRPs than the three large IOUs. For the purposes of DRP guidance, the CASMU members are directed to file DRPs that, at minimum, address the five statutory requirements in § 769 as it relates to their distribution systems. They are not required to follow the detailed guidance herein.

IT IS RULED that:

1. Guidance for Section 769 – Distribution Resource Planning attached to this Ruling is adopted, and its contents shall guide the Utility Distribution Resource Plan filings.
2. The Investor-Owned Utilities shall file their Distribution Resource Plans as Applications no later than July 1, 2015.
3. Small and Multi-Jurisdictional Utilities shall be allowed to submit simplified Distribution Resource Plans no later than July 1, 2015 that address the statutory of Section 769, but do not conform to the Guidance for Section 769 – Distribution Resource Planning that is attached here.

Dated February 6, 2015, at San Francisco, California.

/s/ MICHAEL PICKER
Michael Picker
Assigned Commissioner

ATTACHMENT

Guidance for Section 769 – Distribution Resource Planning

Guidance for Section 769 – Distribution Resource Planning

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Guidance Distribution Resource Plan Requirements and Definitions

This guidance ruling is intended to define a framework for the Utility Distribution Resource Plans (DRPs) that has three major sections: 1) the framework section that describes the structure and intended content of the DRPs, 2) the description of phasing of next steps and 3) the definitions section which defines certain terms in PUC §769 and how the Utilities will interpret these terms in the DRPs.

DRP Content Guidance

1. Integration Capacity and Locational Value Analysis Section

This section directs the Utilities to develop three analytical frameworks related to the grid integration capacity of Distributed Energy Resources (DER), the quantification of DER locational value, and the future growth of DERs. The intent is to create a set of mutually supportive tools that detail how much DER can be deployed under a business as usual grid investment trajectory, and build the capabilities to compare portfolios of DERs as alternatives to traditional grid infrastructure. In recognition of the fact that the Utilities have started elements of this work already, they are directed to take into account work they have previously conducted, or are currently working on, through their Smart Grid Deployment Plans and their EPIC Investment Plans.

a. Integration Capacity Analysis

This analysis will specify how much DER hosting capacity may be available on the distribution network. Worksheets should be provided by the Utilities that show evaluation of available capacity down to the line section or node level. One of the goals of this analysis is to improve the efficiency of the grid interconnection process through coordination between this work product and each Utility's Rule 21 interconnection, Rule 15 main extensions and Rule 16 service connection study processes. To implement this analysis, the Utilities shall do the following in their DRP filings:

i. Perform a distribution system Integration Capacity Analysis down to the line section or node level, utilizing a common methodology across all Utilities. This analysis quantifies the capability of the system to integrate DER within thermal ratings, protection system limits and power quality and safety standards of existing equipment. Results of the analysis are to be published via online maps maintained by each Utility and available to the public. Initial Integration Capacity Analysis is to be completed by each Utility by July 1, 2015.

ii. Perform an analysis that assesses current system capability together with any planned investments within a 2 year period. Clearly articulate the assumptions and methodology used for load and DER forecasts over the 2 year period.

iii. Perform an analysis using dynamic modeling methods, which are uniform across all Utilities, and circuit performance data. The analysis shall avoid the use of heuristic approaches where possible.

iv. Assess the state of DER deployment and DER deployment projections. For each of the identified DERs, the Utilities should provide current levels of deployment territory wide, plus an assessment of geographic dispersion with circuits that exhibit high levels of penetration identified.

v. If a Utility is unable to conduct dynamic analyses for all feeders down to the line section or node, as an initial phase the Utility shall conduct an integration capacity analysis on a select set of representative circuits, including all related line sections. Utilities shall agree, as necessary, on the methodology used to select the representative circuits. The Utilities must include their methodology for selecting representative circuits as part of this analysis. The analysis of representative circuits described in this section should not be construed as a substitute for the ultimate goal of fully analyzing all distribution circuits in the Utility service territory, but should be considered as an initial phase for the July 1 filing.

vi. Specify a process for regularly updating the Integration Capacity Analysis to reflect current conditions. The process in place for updating the Renewable Auction Mechanism monthly is a good starting point. Where current Utility capabilities are inadequate to conduct a dynamic, line section -level integration capacity analysis, specify a plan for developing these capabilities, including a schedule.

vii. Specify recommendations for utilizing the Integration Capacity Analysis to support planning and streamlining of Rule 21 for distributed generation and Rule 15 and Rule 16 assessments of EV load grid impacts, with a particular focus on developing new or improved 'Fast Track' standards.

b. Optimal Location Benefit Analysis

This analysis will specify the net benefit that DERs can provide in a given location. To implement this analysis, the Utilities shall develop the following and file as part of their DRPs:

i. A unified locational net benefits methodology consistent across all three Utilities that is based on the Commission approved E3 Cost-Effectiveness Calculator, but enhanced to explicitly include location-specific values (ex: LMP-specific avoided energy costs, avoided Local Resource Adequacy Procurement), and at minimum include the following value components:

1. Avoided Sub-transmission, Substation and Feeder Capital and Operating Expenditures: DERs' ability to avoid Utility costs incurred to increase capacity to ensure the system can accommodate forecasted load growth
2. Avoided Distribution Voltage and Power Quality Capital and Operating Expenditures: DERs ability to avoid Utility costs incurred to ensure power is delivered within required operating specifications, including transient and steady-state voltage, reactive power and harmonics
3. Avoided Distribution Reliability and Resiliency Capital and Operating Expenditures: DERs ability to avoid Utility reliability related costs incurred to prevent, mitigate and respond to routine outages (Utilities shall identify specific reliability metrics DERs could improve), and resiliency related costs incurred to prevent, mitigate, or respond to major or catastrophic events (Utilities shall identify specific resiliency metrics DERs could improve)
4. Avoided Transmission Capital and Operating Expenditures: DERs ability to avoid need for system and local area transmission capacity
5. Avoided Flexible Resource Adequacy (RA) Procurement: DERs ability to reduce Utility flexible RA requirements
6. Avoided Renewables Integration Costs: DERs ability to reduce Utility costs associated with renewable integration (for this line item, the Utilities shall attempt to coordinate their efforts with the development of the updated RPS Calculator and the Renewables Integration Charge)
7. Any societal avoided costs which can be clearly linked to the deployment of DERs
8. Any avoided public safety costs which can be clearly linked to the deployment of DERs
9. Definition for each of the value components included in the locational benefits analysis

10. Definition of methodology used to assess benefits and costs of each value component explicitly outlined above, irrespective of its treatment in the E3 Cost-Effectiveness Calculator
11. Description of how a locational benefits methodology can be integrated into long-term planning initiatives like the Independent System Operator's (ISO) Transmission Planning Process (TPP), the Commission's Long Term Procurement Plan (LTPP), and the California Energy Commission's (CEC) Independent Energy Policy Report (IEPR), including any changes that could be made to these planning process to facilitate more integrated analysis

ii. A process for maintaining on-going updates to the DER Integration Capacity Analysis and the Optimal Location Benefits Analysis

c. DER Growth Scenarios

As part of the DRPs, the Utilities shall develop three 10-year scenarios that project expected growth of DERs through 2025, including expected geographic dispersion at the distribution feeder level and impacts on distribution planning. The three scenarios shall be based on the following criteria:

i. Scenario 1: Adapts the IEPR "Trajectory" case for DER deployment for distribution planning at the feeder lever, down to each line section
ii. Scenario 2: Adapts the IEPR "High Growth" case for DER adoption but also incorporates additional information from Load Serving Entities (LSEs), 3rd party DER owners, and DER vendors
iii. Scenario 3: Based on very high potential growth in the use of DERs to meet transmission system needs, resource adequacy, distribution reliability, resiliency, and long-term greenhouse gas (GHG) reductions, with key inputs drawn from achieving goals such as:
    1. Governor's 2030 Energy Policy Goals:
        a. 50% share of electricity from renewables
        b. Reduction of petroleum used by cars and trucks by half
        c. Reduction of electricity used in existing buildings by half and the development of cleaner heating fuels
    2. Zero Net Energy Goals[1]
    3. 2030 GHG reductions identified in the Air Resources Board's 2014 Scoping Plan Update
    4. Governor's Zero Emission Vehicle Action Plan
    5. Commission's 2020 Energy Storage Requirements
    6. Commission's Demand Response (DR) Goal of 5% of peak load managed by DR
    7. Reduction in the cost and frequency of routine outages
    8. Reduction in the cost and improved responsiveness to major or catastrophic events

2. Demonstration and Deployment

As the Utilities develop new analytics it is critical that they demonstrate the capabilities of DERs to meet grid planning and operational objectives described in the DRPs. With this in mind, the Utilities are

[1] The Road to ZNE: Pathways to ZNE Buildings in California (2012)

directed to propose DER-focused demonstration and deployment projects. These projects are intended to demonstrate integration of locational benefits analysis into Utility distribution planning and operations. Where feasible, these demonstration projects should be coordinated with on-going efforts associated with each Utility's smart grid deployment plan and EPIC investment plan. The Utilities shall work closely with Load Serving Entities, third-party DER providers and DER technology vendors through the design of these demonstration projects. Through this collaboration, all stakeholders shall pay particular attention to issues related to data exchange. The Utilities shall include any expected cost recovery for these demonstration projects as part of their DRP Applications, including any specific proposals related to minimum cost thresholds requiring Commission approval. To implement this guidance, the Utilities shall include the following in their DRP filings:

a. Demonstrate Dynamic Integrated Capacity Analysis

Develop a specification for a demonstration project where the Utilities' Commission-approved Integration Capacity Analysis methodology is applied to all line sections or nodes within a Distribution Planning Area (DPA). The specification should include a detailed implementation schedule. This demonstration shall utilize fully dynamic modeling techniques for all line sections or nodes within the selected DPA. This demonstration shall consider two scenarios:

i. The DER capacity does not cause power to flow beyond the substation busbar.
ii. The DERs technical maximum capacity is considered irrespective of power flow toward the transmission system.

This Demonstration project shall be scoped to commence no later than 6 months after Commission approval of the DRP.

b. Demonstrate the Optimal Location Benefit Analysis Methodology

Develop a specification for a demonstration project where the Utilities' Commission-approved Optimal Location Benefit Analysis methodology is performed for one DPA, including a detailed implementation schedule. In selecting which DPA to study, the Utilities shall, at minimum, evaluate one near term (0-3 year project lead time) and one longer term (3 or more year lead time) distribution infrastructure project for possible deferral. This Demonstration project shall be scoped to commence no later than 1 year after Commission approval of the DRP.

c. Demonstrate DER Locational Benefits

Develop a specification for a demonstration project where at least three DER avoided cost categories or services for which only "normative value data" presently exist (e.g. avoided resource adequacy capacity, distribution capacity deferral, voltage/reactive power management) can validate the ability of DER to achieve net benefits consistent with the Optimal Location Benefit Analysis. The specification should include a detailed implementation schedule. Such a DER demonstration project will either displace or operate in concert with existing infrastructure to provide the defined functions. This demonstration shall also explicitly seek to demonstrate the operations of multiple DER types in concert, and shall explain how minimum-cost DER portfolios were constructed using locational factors such as load characteristics, customer mix, building characteristics and the like. This demonstration project shall be scoped to commence no later than 1 year after Commission approval of the DRP. Use cases shall employ services obtained from customer and/or 3rd party DERs. Each Utility shall specify products and services employed to obtain the avoided costs or net benefits, and shall specify related transaction methods (e.g. contract, tariff, marginal price) by which customer and/or 3rd party DERs will provide services under the demonstrations.

d. Demonstrate Distribution Operations at High Penetrations of DERs

Develop a specification for a demonstration of high DER penetrations that integrates the Utilities' distribution system operations, planning and investment for implementation. This analysis of potential benefits and locational values associated with high-DER penetration should be conducted at the Substation level and involve up to 5 circuits, and may serve as a prototype model that could be applied on a wider scale upon completion and refinement. This project shall also explicitly seek to demonstrate the operations of multiple DERs in concert, and operational coordination with third-party DER owners/operators/aggregators and as part of this component of the project shall explain how DER portfolios were constructed. This demonstration shall employ some quantity of third party-owned and -operated DERs, and may include Utility-owned DERs. This demonstration project shall be scoped to commence no later than 1 year after Commission approval of the DRP.

e. Demonstrate DER Dispatch to Meet Reliability Needs

Develop a specification for a demonstration project where the Utility would serve as a distribution system operator of a microgrid where DERs (both third party- and Utility-owned) serve a significant portion of customer load and reliability services. This project shall also explicitly seek to demonstrate the operations of multiple DERs as managed by a dedicated control system, and as part of this component of the project shall explain how DER portfolios were constructed, as well as how they are being dispatched or otherwise managed. This demonstration shall define necessary operational functionalities. This demonstration shall employ some quantity of third party DERs, and may include Utility-owned DERs. This demonstration project shall be scoped to commence no later than 1 year after Commission approval of the DRP.

3. Data Access

Many of the above sections require various amounts and types of data to be transferred between the Utilities and third parties. In some cases, the Utilities may "own" (generate or acquire) the data and in some cases the data may be owned or generated by either the customer or the third party. Data sharing involves a mechanism for communicating the data among the Utilities, customers and DER owners/operators. The type of data that will be shared depends necessarily on the proposed use of the data, and what the use of the data enables, for customers, the market, and the Utility. The following types of data have been mentioned by various parties as important to furthering the goals of the DRP process:

Utility Planning Data

- Existing distribution characteristics at substation and feeder-level — coincident & non-coincident peaks/ capacity levels/ outage data/ projected investment needs

- Electric vehicle and charging station populations
- Existing distributed generation (DG) population characteristics
- Backup generator population
- Generation production characteristics, associated with intermittent resources
- Existing combined heat and power installations

Market Data

- Demographics: household income levels, CARE customers
- Customer DG adoption forecasts
- Other customer DER adoption forecasts
- Distribution Planning load forecasts, based on forecasting scenarios proposed elsewhere in the plan

The Commission has recently litigated privacy issues related to sharing customer usage and usage-related data with third parties. Commission Decision (D.) 14-05-016 established aggregation thresholds beyond which customer-level consumption, billing and account information may be shared with third parties without explicit customer consent. The majority of distribution system characteristic and planning data are not expected to be subject to the restrictions set forth in D.14-05-16 as they do not contain information that can reasonably be used to identify an individual, family, household, residence, or non-residential customer. However, certain specific types of data may contain such information, for example, feeder-level data on daily coincident and non-coincident peaks for feeders that serve relatively few customers. Utilities may need to develop methods for aggregating or anonymizing these datasets such that their release satisfies privacy requirements while still supporting the goals of the DRP.

With this in mind, the Utilities should include the following in their DRPs related to data access:

a. Proposed Policy on Data Sharing

i. Types of data that will be shared, including, but not limited to, all data fields referenced herein
ii. Requirements for receiving data from DER owners (DER owners/operators)

b. Procedures for Data Sharing

i. Proposed process for sharing data with customers and DER owners/operators. Where data is deemed to be confidential for competitive or security reasons, an explanation for why data cannot be shared and a proposed alternative to sharing data that still supports goals of DRPs. Where data release is deemed to infringe on customer privacy, an explanation for why data release would violate restrictions set out in D.14-05-16, D.11-07-056[2] or other specific state or federal statutes, and a proposed method for aggregating or anonymizing data so that it may be shared with third parties.

[2] California Public Utilities Commission, Decision Adopting Rules to Protect the Privacy and Security of the Electricity Usage Data of the Customers of Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company (Decision (D.)11-07-056) (July 29, 2011).

ii. Proposed method for making this data available in as near real time as possible, subject to existing privacy constraints, with explicit consideration for how third parties can access this data directly, using the ESPI Customer Data Access system.

iii. Proposed process for sharing market data from DER owners/operators with Utilities, including policies that deal with confidentiality.

c. Grid Conditions Data and Smart Meters

i. Process for making public feeder-level grid conditions data, such as what is provided by distribution sensor networks and substation automation systems, including coincident & non-coincident peaks, capacity levels, outage data, real and reactive power profiles, impedances and transformer thermal and loading histories, and projected investment needs over the following 10 years

ii. Description of Utilities' current plans for obtaining data from smart meters, beyond interval billing data, that reflect power quality and other factors. These data potentially include voltage, frequency, reactive power/power factor

iii. Process for making data from new sources, such as sensor systems, SCADA systems, substation automation systems, available in a form where it can be analyzed and correlated with existing data sources

iv. Plan for how Utilities can leverage DER owner/operator data

4. Tariffs and Contracts

The DRPs may "propose or identify standard tariffs, contracts or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives." For the purposes of these DRPs, discussion of new or modified tariffs and contracts should be limited to their applicability in demonstration projects. To implement this guidance, the Utilities shall include the following in their DRP filings:

a. An outline of all relevant existing tariffs that govern/incent DERs (e.g. NEM, EV-TOU, Rule 21)
b. Recommendations for how locational values could be integrated into the above existing tariffs for DERs
c. Recommendations for new services, tariff structures or incentives for DER that could be implemented as part of the above referenced demonstration programs
d. Recommendations for further refinements to Interconnection policies that account for locational values

5. Safety Considerations

Although the utilities must comply with applicable safety and reliability standards in the Public Utilities Code and General Orders, it may be necessary to propose new or modify existing standards in order to accommodate high levels of DER. For the purposes of these DRPs, the Utilities shall include the following in their filings:

a. Catalog of potential reliability and safety standards that DERs must meet and a process for facilitating compliance with these standards. Are there differing requirements or standards that should be considered for different types of DERs?

b. Description of how DERs and grid modernization could support higher levels of system reliability and safety (e.g. improved SAIDI/SAIFI, resiliency, improved cyber security)
c. Description of major safety considerations involving DER equipment on the distribution grid that could be mitigated or obviated by technical changes
d. Description of education and outreach activities by which the Utility plans to inform and engage local permitting authorities on current best practice safety procedures for DER installation, so that local permitting of DER equipment is not outdated, onerous or overly prohibitive or limiting of otherwise safely and soundly designed projects

6. Barriers to Deployment

The DRPs shall identify any barriers to deployment of DERs as specified in PUC §769 and outlined in the Definitions section herein. The DRPs shall focus on three categories of barriers:

a. Barriers to integration/interconnection of DERs onto the distribution grid

b. Barriers that limit the ability of a DER to provide benefits

c. Barriers related to distribution system operational and infrastructure capability to enable DER provided value related to needed investment in advanced technology such as advanced protection and control systems, telecommunications and sensing.

Within each of the identified types of barriers, the DRPs shall categorize the barriers as follows:

- Statutory: statutory prohibitions (e.g. inability of a large campus with a single master meter to deploy more than 1 MW of NEM)
- Regulatory: regulatory rules or processes that increase cost of DER deployment or limit DER functionalities (e.g. potential limitations to DER deployment associated with use of the Energy Services Provider Interface (ESPI) as a data access method. For example, the fact that ESPI data may or may not be deemed "revenue quality" for settlement purposes with CAISO is one such potential limitation)
- Grid Insight: lack of visibility into distribution system conditions, Bulk Electric System conditions, or actual performance of DERs that limit DER deployment of operations. A prime example of this barrier is the lack of access to both customer usage and grid conditions data for non-Utility stakeholders and lack of access to DER system performance for the Utility.
- Standards: inadequate or undefined standards (e.g. IEEE 1547 currently does not allow smart inverter functions to be enabled)
- Safety: safety standards related to technology or operation of the distribution circuit (e.g. local fire codes that have not been updated to reflect best in class understanding of fire risks associated with rooftop PV
- Benefits Monetization: lack of a mechanism to monetize DER benefits (e.g. CAISO markets currently do not allow DERs to bid in certain services like spinning reserves)
- Communications: lack of a communications link between DERs and utility grid operators, which limits deployment or benefits-monetization of DER (e.g. inability to sub-meter EVs in the

absence of a smart meter, which increases cost of providing an EV owner a time-of-use rate for their EV consumption)

7. DRP Coordination with Utility General Rate Cases

One of the most critical components of the DRP process will be its interface with the Utilities' General Rate Cases. As the analytical tools and demonstration projects required of the DRPs come to fruition, the interface with each Utility's GRC should become clearer. That said, it is currently too early to direct the Utilities to integrate any given piece of the DRP into their next GRC filing. Instead, the Utilities shall include a section in their DRPs where they describe what specific actions or investments may be included in their next GRCs as a result of the DRP process.

8. DRP Coordination with Utility and CEC Load Forecasting

One of the expected outcomes of the DRP process is greater granularity and accuracy in Utility forecasting of DERs impact on load. This improved and more granular load forecasting will most likely be able to provide input to the IEPR forecast. With this in mind, each Utility should describe how the results of the DRP will influence their own internal load forecasting, the CEC's IEPR load forecast and by extension the Commission's LTPP and the CAISO's TPP.

9. Phasing of Next Steps

As discussed already, the DRPs are likely only to be effective if they serve as the starting point in an on-going effort to integrate DERs into distribution planning, operations and investment. With this in mind, the DRP process should be a living one, where the Commission, the Utilities and stakeholders engage continuously to refine the activities and goals that are central to the DRPs themselves.

a. Rolling Updates to DRPs

Although PUC §769 appears to call for a one-time exercise in this new method of Distribution Planning, there appears to be general agreement that this should really be an on-going, cyclical process distribution planning process (DPP) that will repeat over time to incorporate evolving technologies and market policies and to take advantage of lessons learned in previous cycles.

For this reason, the Utilities shall include in their DRPs a plan for how their DRPs can be updated on a biennial filing cycle. Included in this component of the DRPs shall be a proposal for rolling updates to the DRPs occurring at least every two years for the next ten years, including a clear mapping of how these subsequent DRP phases will interact with each Utility's GRC, as well as other funding authorizations, like Commission Energy Efficiency Programs.

b. Phased Approach to DRP filings

As part of the Commission's consideration of July 1 DRP filings, the Commission will consider and potentially approve a scope for subsequent DRP filings. Commission Staff have developed recommendations for a phased approach to the DRP process over a 10-year time horizon and synchronized with GRC, LTPP and TPP processes.

As part of their DRP filings, the Utilities shall include a proposal that either adopts, or adopts with amendments, the following set of recommendations:

1. Phase 1 (2 years, 2016-2017)

This phase will primarily focus on the evaluation of the capacity of the distribution system to support DER under the current load forecasting scenarios. The evaluation granularity should ideally be at the substation level. Utilities will need to develop or acquire tools to support this effort. Models of DER should be developed during this phase that will enable testing of scenarios. The tool development should include analysis and design of system instrumentation (sensors) required to provide input data to distribution system models.

The deliverables of this phase should include GIS maps and power flow models of the entire distribution system to the substation level that are available in a standard format that is tool independent. In order to support third party participation in determination of optimal locations, there should be the necessary policy support for third party access to maps and models. This phase will also include planning and design of communications infrastructure to support interconnection of DER for monitoring and control.

2. Phase 2a (2 years, 2018-2019)

During this phase, the methodology defined in Phase 1 will be employed to determine impacts on the distribution system at the substation or feeder level. The process will be executed across the distribution system using DER models developed in Phase 1. This will provide information that can be used to identify both optimal locations and combinations of DERs that can provide services in those locations. As possible, given funding constraints, Utilities will continue to deploy sensors and communications infrastructure designed in Phase 1, and continue data collection and analysis. Simulation of DER portfolios using models developed in Phase 1 should be completed using data acquired via monitoring and communications systems to determine impacts on the distribution system.

The output of this phase will be “Distributed Energy Resource Development Zones” (could be Distribution Planning Areas) that can be associated with locational values. In these zones, additional DER portfolios would be defined using the process of value optimization. The value optimization methodology will specify tools and processes to compare DERs as an alternative to traditional Distribution infrastructure investments, including both operations and economic factors.

Utilities will specify tools and processes to compare DERs as alternative providers of distribution reliability functions, including voltage regulation, etc. In addition, Utilities will specify processes for utilizing the above tools, including incorporating stakeholder input and feedback into analytical methods.

3. Phase 2b (Ongoing, 2018 and Beyond)

This phase will entail stakeholder-driven development of DER procurement policy and mechanisms for the IOUs. The procurement policy will be competitively neutral and will accommodate development of non-utility-owned distribution systems such as islandable microgrids and parallel direct current and thermal distribution systems.

These activities will also include the development of Distribution System Markets that can support grid service transactions. On an ongoing basis, the IOUs will update distribution system status in terms of DER deployment and associated system impacts.

Based on these ongoing activities, a stakeholder-driven process will develop an analytical plan for how these deployment scenarios would impact distribution planning and identify gaps that exist in current plans to support achieving each of the scenarios. The DRPs will specify a plan for developing a rolling 5 year DER forecast to be included in distribution infrastructure planning, including how the forecast will influence distribution expenditures.

Definitions

PUC §769 uses several key terms with regard to specifying the content of the DRPs, but does not define them. This Rulemaking will offer definitions based on the record, industry practice and interviews with stakeholders. These definitions are intended to provide the basis for methodologies that will be described in the plans. The terms defined here are a) distributed energy resources, b) optimal locations, c) locational values and benefits, and d) cost-effectiveness.

Distributed Energy Resources

For the purposes of the DRPs, PUC §769 defines distributed resources as "distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies." Given that these are somewhat broad categories, the DRPs should, at minimum, consider the following categories of DERs, with a particular focus on instances where multiple DERs are operating in concert:

Distributed Renewable Generation

- Distributed Generation – PV
- Distributed Generation – Wind
- Distributed Generation – Stationary Fuel-Cell*
- Distributed Generation – CHP*
- Distributed Generation – Stationary I-C Engine*

Energy Efficiency

- Energy Efficiency – Residential
- Energy Efficiency – Small Commercial
- Energy Efficiency – Large Commercial
- Energy Efficiency – Industrial

Energy Storage

- Energy Storage – Customer Side
- Energy Storage – Utility Side

Electric Vehicles

- Electric Vehicles – Residential Charging
- Electric Vehicles – Workplace/Public Charging
- Electric Vehicles – Managed Charging (VG1)
- Electric Vehicles – Bi-Directional Power Flow (VG2)

Demand Response

- Demand Response – Residential/Small Commercial
- Demand Response – Large Customer

**Other DER*

These three categories of DG have the potential to be fueled by renewables, but to date most deployments have been natural gas fueled. Given that the statute defines distributed resources as having to be "renewable," the DRPs must first focus on the analysis of Fuel Cells, CHP and Internal Combustion engines that are fueled by renewables. That said, natural gas-fueled stationary Fuel Cells, CHP and stationary I-C engines have the potential to reduce GHG emissions, and so the utilities are encouraged to expand the scope of their DRPs to include any distributed generation that can produce GHG emissions reductions over its lifecycle.

Optimal Locations

Optimality is usually defined as a minimum or maximum of some function or set of functions. In the case of DERs, a location is optimal if:

- Some quantity of DER can be interconnected without grid upgrades or with low or no interconnection cost, i.e., minimum distribution grid impact.
- DERs can serve as a solution, e.g. in Distribution Substation areas where DER can defer distribution upgrades or reduce operations and maintenance expenses.
- The deployment of DERs in a specific location, particularly Resource Adequacy Local Capacity Areas, can be demonstrated to defer new generation or transmission.
- A DER can ensure the provision of safe and reliable grid operations in a specific location.
- A DER can enhance the reliability of service and resiliency against service interruptions at a specific location.
- DER deployment can provide other benefits such as economic, environmental or social equity at a specific location.

Determination of optimality using the above definitions should also include consideration of whether the DER deployment utilizes customer side (behind the meter) or utility side (in front of the meter) interconnection.

Locational Values and Benefits

"Locational Value" is defined here as monetary value that accrues to the customers and/or the utility associated with the provision of a specific service at some defined location.

"Benefits" as defined here can either be economic, operational (from the utility perspective) or societal, and locational benefits are generally defined as monetary value that can be assigned to some location using a set of criteria.

The method for assessment of "benefits" should be based on considerations of how to flow locational benefits through to customers, either in terms of rates, incentives or other mechanisms.

Cost-Effectiveness

Cost-effectiveness standards are already applied to customer side distributed generation. It is not the goal of this proceeding to redefine how these cost-effectiveness standards are calculated or applied. Instead, this proceeding will utilize and build upon existing cost-effectiveness standards so they are congruent with the locational value orientation of PUC §769. That said, the DRPs seek to go beyond existing models of DER deployment, and as such current cost-effectiveness may be insufficient to fully characterize the value of DERs. For example, distributed generation programs utilize the E3 Avoided

Cost Calculator, yet the tool does not have the capacity to account for the potential of DG to provide differential avoided distribution infrastructure costs based on the location of the DG. This type of analysis is central to the DRPs, and so the DRPs must be able to go beyond the current cost-effectiveness protocols where needed.