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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ASSIGNED COMMISSIONER'S RULING RE DRAFT GUIDANCE FOR USE IN UTILITY AB 327 (2013) SECTION 769 DISTRIBUTION RESOURCE PLANS

On August 14, 2014, the Commission issued Rulemaking 14-08-013 Regarding Policies, Procedures and Rules for the Development of Distribution Resource Plans. This Rulemaking included a draft Scoping Memo that put forward 16 questions for parties to comment upon. Attached to the draft Scoping Memo, and included in the questions for parties, was a paper entitled, "More Than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient." Over 30 parties responded with comments or replies. On September 17, 2014, Energy Division held a workshop to discuss party comments to the Draft Scoping Memo and the "More Than Smart" paper.

In comments, parties provided a wide variety of recommendations for the types of Distribution Resource Plan guidance the Commission should provide the Utilities. After careful consideration of these comments, review of similar proceedings in states like New York and Hawaii, and discussions with a wide variety of stakeholders, I have, in collaboration with Energy Division, developed

the attached draft Distribution Resource Plan Guidance (Draft Guidance) document.

Parties may file comments on the attached Draft Guidance by December 5, 2014. Subsequent to the submission and review of comments, I will issue a Ruling with a Final Distribution Resource Plan Guidance document that will serve as the basis for utility Applications. My intention is to consolidate these forthcoming Applications with this Rulemaking.

The following is a summary of the attached Draft Guidance:

1. In Part 1, the Draft Guidance suggests a “New Framework for Distribution Planning” driven by the imperative of deep greenhouse gas emissions reductions, and enabled by the mass adoption of Distributed Energy Resources.
2. In Part 2, the Draft Guidance suggests that the jurisdictional scope of the proceeding should be the low-voltage distribution, while also identifying where this proceeding overlaps with other Commission proceedings.
3. In Part 3, the Draft Guidance identifies the need for on-going coordination between the Utilities, State Agencies and the Independent System Operators. The Draft Guidance also suggests that the Demand Response Providers (DRP) filings be submitted as Applications. Finally, the Draft Guidance addresses the applicability of the Guidance to Small and Multi-Jurisdictional Utilities.
4. In Part 4, the Draft Guidance lays out the requirements for the DRP filings, including: a) the development of Integration Capacity and Locational Value Analysis tools; b) the development of Demonstration projects; c) the provision of data access; d) an assessment of tariff and contract implications; e) the identification of safety considerations; f) the description of barriers to Distributed Energy Resources deployment; g) an explanation of how the DRP filings will be coordinated with the Utility general rate cases; and h) a description of proposed next steps.

IT IS RULED that that parties may submit comments on the draft Distribution Resource Plan Guidance attached to this Ruling no later than December 5, 2014.

Dated November 17, 2014, at San Francisco, California.

/s/ MICHAEL PICKER

Michael Picker
Assigned Commissioner

ATTACHMENT

Draft Guidance Document for R. 14-08-013

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Part One: Introduction

On August 14, 2014, the California Public Utilities Commission initiated Rulemaking (R.14-08-013) to establish policies, procedures, and rules to guide California investor-owned electric utilities (Utilities) in developing their Distribution Resources Plan Proposals, which they are required by Public Utilities Code Section 769 to file by July 1, 2015. This rulemaking also will evaluate the Utilities' existing and future electric distribution infrastructure and planning procedures with respect to incorporating Distributed Energy Resources (DER) into the planning and operations of their electric distribution systems.

Subsequent to the Rulemaking, the Staff of the Energy Division conducted a workshop on September 17, 2014, to provide a forum for Investor-Owned Utilities (IOUs) and stakeholders to explore issues raised by § 769. The workshop also previewed positions subsequently raised in Comments on the Order Instituting Rulemaking (OIR) that were filed and served on September 22 and Replies that were filed and served October 6, 2014.

This DRAFT document provides additional clarification of several issues raised by Parties and sets out preliminary guidance for content and structure of the Distribution Resources Plans (DRPs) that will be filed by July 1, 2015. The DRPs filed by July 1, 2015 should be consistent with each other in structure and content so they may be more easily compared and analyzed. While each Utility'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.

Therefore, as per the Assigned Commissioner's Ruling that releases this Draft Guidance document, Parties are asked to file and serve comments on this Draft Guidance by December 5, 2014. Reply comments are not specifically requested. A subsequent Assigned Commissioner's Ruling will be issued on approximately February 1, 2015 that includes the Final Guidance on the DRPs in advance of the Utilities' July 1, 2015 DRP filing deadline.

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 Utilities’ distribution system. 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

Public Utilities Code Section (§) 769 (established by AB 327) requires Utilities 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. The primacy of AB 32 and Executive Order S-21-09 mean that, in order to deliver benefits, major energy policies initiatives must necessarily 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 the 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 is 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 Utilities, 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 Utilities 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 Utilities 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, and this document provides some initial guidance to Parties on how to define optimal locations, and what tools are available to conduct technical analysis of existing circuits to allow for far deeper penetration of DER, while minimizing necessary system upgrades.

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 Utility'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 Utilities to adopt a biennial DRP filing cycle. 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. The OIR decision correctly 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 revolutionary.

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 this Guidance document. Nonetheless, there may be opportunities in the context of this proceeding to begin exploring ideas for the future – this can only benefit the Commission, Utilities and Parties in understanding the long-term implications of the actions that we begin today. This is why the Commission has recognized and continues to align this proceeding with the *More Than Smart* initiative (described in more detail below).

It is the intent of this 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 Utilities, consumers, third-party DERs providers and the California Independent Systems 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 this document provides a proposed schedule for phasing future planning developments and activities over a longer term time horizon.

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. DSOs 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.

Part Two: Description of Purpose and Scope of the Guidance

The following guidance to the Utilities is intended to describe the structure and contents of the Distribution Resources Plans the Utilities 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 will clearly describe 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.

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 (4kV – 16kV or lower) and at sizes of 20 MW or less. This definition puts all DER within the jurisdiction of the Commission, except to the extent that distribution-connected or interconnecting DER may participate in the wholesale market.

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)

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 Utilities 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 NEM 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.

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, Senate Bill 1414 (Wolk, 2014), has been recently signed into law to amend Public Utilities Code Sections 380 and 380.5 to establish policies to incorporate demand response (DR) within the Resource Adequacy requirements that Utilities 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.

Part Three: Commission Oversight

Coordination among Utilities, State Agencies and ISO

Going forward, it is critical that DRP activities be coordinated among the three Utilities, the CAISO, and the California Energy Commission (CEC), as well as the CPUC. Increasing penetrations of DER connected at the distribution level pose operational, planning and policy development challenges for the CAISO 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.

CPUC Process

The general schedule of this proceeding was outlined in R.14-08-013 to include the issuance of this Guidance document for public comment and a Commission determination or ruling in early 2015 to allow for Utilities to incorporate both a broad vision and principle, and specific Commission recommendations in their DRPs filings.

While that 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. As part of the final Guidance document, Staff may propose a schedule or menu of workshops or activities to this end.

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.

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 investor owned utilities. 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.

Part Four: Guidance Distribution Resource Plan Requirements and Definitions

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

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 DER, the quantification of DER locational value, and the future growth of DERs. The intent being to create a set of mutually supportive tools that at once detail how much DER can be deployed under a business as usual grid investment trajectory, while building 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 capacity may be available on the Distribution network. Worksheets should be provided by the Utilities that show evaluation of available capacity down to the circuit level. To implement this analysis, the IOUs shall include the following in their DRP filings:

- i. Perform an Integration Capacity Analysis of their distribution system to the circuit level based on the capability of the system to integrate some quantity of DER within thermal ratings, protection system limits and power quality and safety standards. Results of analysis to be published via online circuit level maps maintained by Utilities and available to the public. Initial Integration Capacity Analysis to be completed by each Utility by July 1, 2015.

- ii. Perform analysis to assess current system capability and any planned investments within 2 year period and clearly articulated assumptions for any changes in load and DER growth over the 2-year period.
- iii. Perform analysis using dynamic modeling methods while avoiding of heuristic approaches.
- 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 assessment of geographic dispersion and identify circuits that exhibit high levels of penetration.

b. Specify a process for regularly updating the Integration Capacity Analysis to reflect current conditions. The current process in place for updating the Reverse Auction Mechanism that requires monthly updates is a good starting point. Optimal Location Benefit Analysis:

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

- i. A unified locational net benefits methodology consistent across all three Utilities that shall include, at minimum, the following criteria:
 - 1. Avoided capital costs for distribution upgrades
 - 2. Avoided O&M
 - 3. Avoided electricity purchases -- quantified in terms of both retail rates and nodal wholesale prices
 - 4. Avoided Resource Adequacy (RA) purchases -- to include system, local and flexible RA (where applicable)
 - 5. Avoided energy losses for distribution system and transmission
 - 6. Improved distribution system reliability and resiliency. Within the this criteria, the Utilities shall identify specific reliability and resiliency metrics that

DERs could improve (ex: distributed storage reducing SAIFI and SAIDI)

7. Additional Safety-related criteria
8. Definition for each of the benefit and cost criteria included in the locational benefits analysis
9. Description of how a locational benefits methodology can be integrated into distribution infrastructure planning and investment decisions, as well as long-term planning initiatives like the ISO's TPP, the Commission's LTPP, and the CEC's IEPR.

ii. Maintenance and Updates to Locations Analysis:

1. Specify 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 ten-year scenarios that project expected growth of DERs through 2025, including expected geographic dispersion at the distribution substation 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,
- ii. Scenario 2: Adapts the IEPR "High Growth" case for DER adoption, and
- iii. Scenario 3: Based on very high potential growth in the use of DERs to meet transmission system needs and resource adequacy, with key inputs drawn from achieving goals like those articulated in Zero Net Energy targets and the Governor's Zero Emission Vehicle Action Plan.

2. Demonstration and Deployment

As new analytical methods are being developed, it is critical that the Utilities develop proof points that demonstrate the capabilities of DERs to meet grid planning and operational requirements. With this in mind, the Utilities are

directed to develop proposals for DER-focused demonstration and deployment projects that seek 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. To implement this guidance, the IOUs shall include the following in their DRP filings:

a. Demonstrate the Optimal Locations Benefits Analysis Methodology:

- i. Perform a Locational Benefits Analysis for one Distribution Planning Area ("Study") that is linked to a known transmission system benefit for the purpose of demonstrating the analysis methodology and stakeholder engagement process. Study shall be completed by July 1, 2015.

b. Demonstrate DER Locational Benefits:

- i. Develop a specification for a demonstration project where at least three DER use-cases (ex: resources adequacy, distribution capacity deferral, voltage/reactive power regulation) can validate the operational effectiveness of DER to achieve net benefits consistent with Locational Benefits Analysis. Such a DER demonstration project will either, a) displace, or b) operate in concert with existing infrastructure, to provide the defined functions. This demonstration shall also explicitly seek to demonstrate the operations of multiple DERs in concert, and as part of this component of the project shall explain how DER portfolios were constructed. This Demonstration project shall be scoped to commence within 1 year of Commission approval of the DRP. Use cases shall employ services obtained from customer and/or 3rd party DER. Each Utility shall specify services for each use case and related transaction method (e.g, contract, tariff, marginal price) by which customer and/or 3rd

party DER will provide services under the demonstrations.

c. Demonstrate Distribution Operations at High Penetrations of DER:

- i. Develop a specification for a distribution planning level area level demonstration of high DER penetrations that integrate into the IOUs 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 involving up to 4 or 5 circuits may serve as a prototype model which upon completion and refinement could be applied on a wider scale. This demonstration shall also explicitly seek to demonstrate the operations of multiple DERs in concert, and as part of this component of the project shall explain how DER portfolios were constructed. This Demonstration project shall be scoped to commence within 1 year of Commission approval of the DRP.

d. Demonstrate Distribution Marginal Pricing:

- i. A specification for a demonstration project that seeks to quantify distribution marginal pricing for a distribution planning area over the course of a normal distribution infrastructure planning horizon. Included as part of this project will be a process for making public the distribution marginal prices that are derived from the project. This Demonstration project shall be scoped to commence within 1 year of 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, by 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:

Distribution system characteristics

- 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 DG population characteristics
- Backup Generator population
- Generation production characteristics, associated with intermittent resources
- Existing combined heat and power installations

Distribution Planning 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.

Given that issues related to accessing customer data have been recently litigated in Commission Decision (D.) 14-05-016, it is prudent for the DRPs to instead focus on addressing data access relating to data not subject to D.14-05-016. 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, an explanation of why data cannot be shared and a proposed alternative to sharing data that still supports goals of DRPs.
- 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.

c. Grid Conditions Data and Smart Meters

- i. 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.

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. Outline all relevant existing tariffs that govern/incent DERs (ex: NEM, EV-TOU, Rule 21).
- b. Develop recommendations for how locational values could be integrated into the above existing tariffs for DERs.
- c. Develop recommendations for new services, tariff structures or incentives for DER that could be implemented as part of the above referenced demonstration programs.
- d. Develop 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. Identify potential reliability and safety standards that DERs must meet and suggest a process for facilitating compliance with these standards. Are there differing requirements or standards that should be considered for different types of DER?
- b. Delineate how DERs can support higher levels of system reliability and safety (e.g. improved SAIDI/SAIFI, resiliency, improved cybersecurity).
- c. Describe major considerations for owners/operators of DER equipment, and for first-responders (fire, police and health professionals).
- d. To the extent possible, describe Utility efforts to inform and engage relevant local authorities that may bear the responsibility for local permitting of DER equipment.

6. Barriers to Deployment

The DRPs shall identify any barriers to deployment of DER as specified in §769 and outlined in Definitions herein. The DRPs shall focus on three categories of barriers: i) Barriers to integration/interconnection of DERs onto the distribution grid, ii) Barriers to limit the ability of a DER to provide benefits; iii) Barriers related to distribution system operational and infrastructure capability to enable DER provision of benefits. For each of these categories of barriers, the DRPs should identify the top three barriers for each type of DER.

- 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 (ex: inability of large campus with 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 (ex: prohibition on using customer smart meter data for settlement in CAISO market);
- Grid Insight: lack of visibility into distribution system conditions, Bulk Electric System conditions, or actual performance of DER that limit DER deployment of operations
- Standards: inadequate or undefined standards (ex: IEEE 1547 currently does not allow smart inverter functions to be enabled);
- Safety: safety standards related to technology or operation of the distribution circuit (ex: 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 mechanism to monetize DER benefits (ex: CAISO market currently does not allow DERs to bid into market to provide certain services like spinning reserve);
- Communications: lack of communications link between DER and utilities grid operator limits deployment or benefits monetization of DER (ex: inability to sub-meter EVs in the absence of a smart meter 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 in 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. 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.

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. 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 the following:

- a. 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 part of the Commission's consideration of these DRPs, the Commission will consider, and potentially approve, a scope for subsequent DRPs. In addition to the requirement of the Utilities to include in their DRPs a "Phasing of Next Steps", Staff has developed the following recommendations for the content of the DRP process should be phased over the next 10 years. As part of their DRP filings, the Utilities shall include:

- b. A proposal that either adopts, or adopts with amendments, the following set of recommendations:
 - i. 10-year time horizon, synchronized with GRC, LTPP and TPP processes.

1. Phase 1: 2 years (2016-17)

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 powerflow 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 (2018-19)

During this phase, the methodology defined in Phase 1 will be employed to determine impacts on 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 DER that can provide services in those locations. As possible, given funding constraints, continue to deploy sensors and communications infrastructure designed in Ph. 1 and continue data collection and analysis. Simulation of portfolios of DER using models developed in Ph. 1 should be completed using data acquired using monitoring and communications systems to determine impacts on distribution system.

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 DER as an alternative to traditional Distribution infrastructure investments, including both operations and economic factors

Specify tools and process to compare DER as an alternative provider of distribution reliability functions, including voltage regulation (etc.).

Specify process for utilizing above tools, including 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 DC and thermal distribution systems.

These activities will also include the development of Distribution System Market 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 what gaps exist in current plans to support achieving each of the scenarios. Specify plan for developing a rolling 5 year DER forecast to be included in distribution infrastructure planning, including how forecast will influence distribution expenditures.

Definitions

§ 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) optimal locations; b) locational value; c) cost effectiveness.

Distributed Energy Resources

For the purposes of the DRPs, §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 a maximum of some function or set of functions. In the case of DER, a location is optimal if:

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

“Benefits” is defined here can either be economic, operational (from the utility perspective) or societal, and locational benefits are generally defined as a 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 or 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 § 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 (DG) 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