Distribution Resources Plan Proceeding (R.14-08-013)

Track 3: Policy

Sub-track 1: DER and Load Forecasting

Assigned Commissioner Ruling, February 27, 2017

Draft Assumptions and Framework Document

Presented by Joint IOUs

April 7, 2017

Table of Contents

I. Executive Summary

Southern California Edison (SCE), Pacific Gas & Electric (PG&E) and San Diego Gas & Electric (SDG&E), collectively Joint IOUs, have developed this Draft Assumption and Framework document, as required by the Assigned Commissioner's Ruling Setting Schedule For Submission of Distributed Energy Resource Growth Scenarios and Distribution Load Forecasting (ACR), dated February 27, 2017. The ACR lists a sequential process that begins with the Joint IOUs submitting this draft document on April 7, followed by a series of stakeholder working group meetings during April 14 through May 26, then Joint IOUs submitting a revised Assumptions and Framework document on June 9, party comments on the document by July 3, and a Proposed Decision adopting assumptions and framework in third quarter of 2017. As stated at the February 10, 2017 DER Assumptions and Methodologies workshop, the Joint IOUs support the process envisioned by the Commission and look forward to participating in the working group meetings over the course of April and May, to revise this draft document based on input from the working group sessions. Joint IOUs also plan to work with stakeholders in the longer run to continue to refine methodologies, use cases and to develop additional DER scenarios.

In this draft document, the Joint IOUs suggest a process for selecting DER adoption assumptions for the Trajectory/Most Likely scenario. The process seeks to satisfy the two key desired attributes discussed at the February 10th workshop and captured in the February 27th ACR: 1) the desire to maintain consistency with the IEPR demand forecast utilized in other planning studies which also rely on DER adoption scenarios such as the IRP and TPP and 2) the desire to use the most recently available DER adoption projections.

Each IOU's load forecast assumptions and methodology are also presented.

Finally, with respect to DER adoption allocation methodologies, the Joint IOUs describe both a long-term vision that they propose to work with stakeholders to implement over the next few planning cycles as well as a near-term description of the allocation methodology which is largely prescribed by the existing distribution planning processes and modeling conventions. The Joint IOUs' proposed long-term vision and near-term allocation methodologies depend upon approval of the recovery of any necessary incremental costs of implementation.

The draft document is structured to provide an appropriate context for more detailed working group presentations on each DER type, which is scheduled to take place during April and May.

II. Regulatory Background

The Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resources Plan (DRP), dated February 6, 2015, directed the utilities to develop three 10-year scenarios for projected growth of DERs through 2025, including estimates of DER geographic dispersion at the distribution feeder level and their impacts on distribution planning. Each utility submitted their methodological approach to develop DER growth scenarios in applications filed on July 1, 2015.

An Assigned Commissioner Ruling finalizing the scope and priority of policy issues in Track 3 of the DRP proceeding was issued on October 21, 2016. Sub-track 1 DER Adoption and Distribution Load Forecasting was developed to examine assumptions and potentially improved techniques the utilities use to forecast loads; how stakeholders and Commission staff can participate in and inform distribution-level forecasting; how distribution planning forecasts can be coordinated with procurement need assessment and transmission planning.[1]

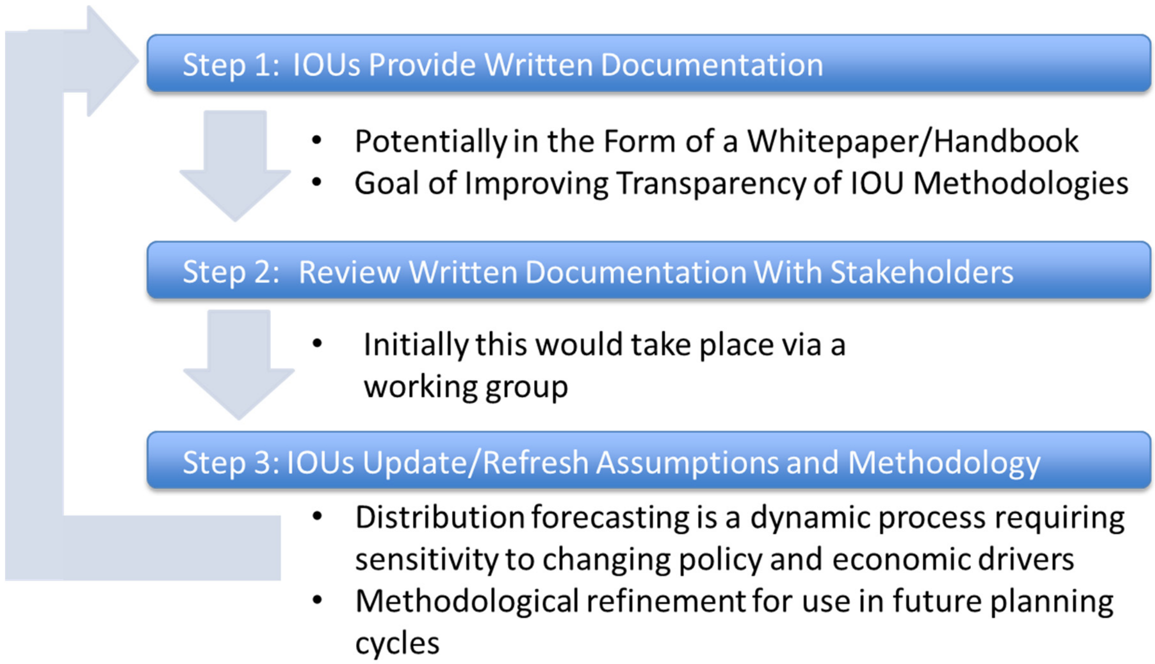
On February 10, 2017, a DER growth scenarios workshop was held to consider the process and methodologies for forecasting the adoption of distributed energy resource (DERs) in order to inform the DRP It also considered the coordination issues and how the DRP will inform CPUC Integrated Resource Planning process (IRP), CEC Integrated Energy Policy Report (IEPR) demand forecast, and CAISO Transmission Planning Process (TPP). The Joint IOUs presented a proposal during the Feb 10 workshop in the DRP's Sub-track 3-1: *DER Growth Scenarios and Distribution Load Forecasting.*

An Assigned Commissioner's Ruling , dated February 27, 2017, was issued that adopts, with one modification, the Joint IOU's proposed schedule and process for developing, vetting and updating of DER growth scenarios was subsequently issued.[2]

The IOUs proposed the following process to ensure consistency and transparency around the DER adoption assumptions and methods used for distribution planning studies:

[1] Assigned Commission's Ruling on Track 3 Issues, October 21 2018

[2] Assigned Commissioner's Ruling Setting Schedule for Submission of Distributed Energy Resource Growth Scenarios And Distribution Load Forecasting, February 27, 2017



The Ruling Included the following schedule:

Date	Activity
April 7, 2017	IOUs develop Draft Assumption and Framework document containing load and DER adoption assumptions and Trajectory/Most Likely scenario to be used for local area planning.
April 14, 2017—May 26, 2017	Working Group meetings will be held to address DER inputs/divergence from statewide planning assumptions and disaggregation methods.
June 9, 2017	IOUs submit revised Assumptions and Framework document
July 3, 2017	Party comments due on revised Assumptions and Framework document
Third Quarter 2017	Proposed Decision (PD) adopting Assumptions and Framework. The PD will also establish annual deadlines for the parties to continue to refine methodologies, use cases, and to develop additional DER scenarios in future iterations.

The Ruling provide guidance on the task of the Working Group: "The working group shall be tasked with **clarifying the use cases, proposing the methodology and assumptions for DER**

adoption scenarios, and developing approaches to disaggregate forecasts to the circuit level."[3]

The Ruling also provided general expectations for the growth scenarios: "While we expect that the growth scenarios will be developed consistent with the IEPR demand forecast used in the IRP and TPP, divergence from state-level assumptions may be necessary based on either better information available regarding the adoption of certain DER resources that has not been previously considered, or considerations regarding unique circumstances in application of the state level assumptions in local planning processes and models."[4]

Finally, the Ruling adopted the following guiding principles:

- Development of growth scenarios needs to be coordinated with IRP and TPP processes in terms of process schedule and consistency of methodology and results.
- Local DER adoption scenarios must support the primary distribution planning objectives of providing safe, reliable, affordable, and clean energy services to customers.
- Input on known DER projects from distribution engineering staff is critical to maintaining reasonable local forecasts.
- Information/feedback from stakeholders representing the various DERs could be beneficial in developing better locational DER adoption scenarios.[5]

III. Trajectory/Most Likely DER Adoption Scenario and Use Cases

A. Summary

The Trajectory/Most Likely DER adoption scenario should represent the utilities' best estimate of DER adoption at the distribution, bank, feeder, substation level. This will support the Assigned Commissioner's Ruling directing that the DER adoption scenarios should support the primary distribution planning objectives of providing safe, reliable, affordable and clean energy services to customers.[6]

B. Primary use cases for the Trajectory/Most Likely DER adoption scenario

The IOUs have identified the following use cases for the trajectory/most likely scenario.

1. Inform the distribution planning process (DPP) with respect to the need for and timing of future infrastructure.

   A foundational component in the utilities' distribution planning process (DPP) is the development and incorporation of load and DER growth assumptions. Both elements

[3] *Ibid* at p. 3.(Emphasis Added)
[4] *Ibid* at p. 3
[5] *Ibid* at p. 4
[6] *Ibid* at p. 4

will influence the outcome of the DPP as well as other processes. Applying the trajectory/most likely DER adoption scenarios into distribution planning will inform distribution planners on the locations of potential DER growth and its impact to the timing of distribution needs, and the potential use of DERs to defer distribution investment needs.

2. Inform the Integration Capacity Analysis (ICA) to identify the locations on the distribution system where and when future DER adoptions may increase or decrease available distribution hosting capacity.

   Integration Capacity Analysis (ICA) determines available capacity on a distribution grid to safely and reliably host DERs (aka hosting capacity). By incorporating the trajectory/most likely DER adoption scenario into the distribution planning process will enable utilities to determine when and where on its distribution feeders are projected to reach its integration capacity limit (i.e. when the distribution feeder integration capacity reaches 0 MW). The assessment would also enable distribution planners to identify specific locations on the feeder requiring additional integration capacity upgrades.

3. Inform the Locational Net Benefits Analysis (LNBA) to indicate the potential value or costs related to future local DER adoptions.

   Locational Net Benefit Analysis (LNBA) will provide an indicative value of potential DER deployment at specific locations on the distribution grid. By incorporating the trajectory/most likely DER adoption scenario, the indicative LNBA results may change.

4. Inform the Distribution Infrastructure Deferral Framework (DIDF) and DER Competitive Solicitation Framework (CSF) regarding the estimated level DER adoptions that are sourced through existing tariffs, programs or other solicitation processes to support development of additional tariffs, programs or solicitations to procure incremental DER adoption as an alternative to more traditional IOU "wires" infrastructure.

IV. Proposed Trajectory/Most Likely DER Adoption Scenario For Use in 2017-2018 Distribution Planning Studies.

A. Context of the IOU approach

The process presented in this section represents what the Joint IOUs feel is the most appropriate approach that balances maintaining the highest level of consistency with contemporaneous planning processes such as the IRP and TPP and the highest level of reliance on the best, most recently available, information.

The objective of this document (and for the Working Group process generally) is to identify the best possible set of assumptions *for use in the 2017-2018 distribution planning cycle*. The PD scheduled Q3 is currently expected to establish annual deadlines for the parties to continue to refine methodologies, use cases, and to develop additional DER scenarios in future iterations.[7] The approaches recommended in this chapter are thus specific to the 2017-18 planning cycle. The IOUs do not necessarily expect to recommend the same approach for the 2019-20 planning cycle; rather, the IOUs expect the approach for the 2018-2019 cycle will be discussed in early- to mid-2018, through a process established in the Q3 PD.

B. Detail of Proposed IOU Approach to Selecting System-Level Planning Assumptions

1. Begin with *the most appropriate public document*. This could be CPUC Assumptions ACR issued via Integrated Resource Plan (IRP) process outlining preferred assumptions and scenarios for use in long term planning processes such as the CAISO transmission planning process (TPP), IOU IEPR submittal[8], or adopted IEPR update. (Note: in odd years the most *recent* document will likely be the IOU IEPR submittal; in even years the most *recent* document will likely be the IEPR draft update (summer) or final update (December).
2. If an IOU wishes to deviate from the assumptions referenced in step 1, compare those assumptions to *the assumption proposed by the IOU.*
3. IOU determines whether there is good cause to adopt the IOU proposed assumption for the distribution planning studies.
4. The IOUs recommend the Working Group discuss appropriate stakeholder review process that would be sufficient for that purpose.

V. Load Forecasting at the Distribution Circuit Level

Each IOU has been forecasting circuit-level load growth for many years. In pursuit of the most effective planning solutions for their respective service territories, each IOU has existing techniques to predict load growth at the circuit-level, at the system-level, as well as growth of mature distributed energy resources. To minimize disruption in the ongoing distribution planning process, a degree of year-over-year consistency is necessary during any transition. It is important to recognize that each IOU has developed methods that best serve its customers by maintaining reliability on each distribution system. This section explains the processes currently employed by each IOU for the purpose of illuminating the areas where alignment is possible and in the best interest of safety, affordability and reliability.

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[7] *Ibid* at p. 3

[8] Portions of the IEPR submittals are confidential, market-sensitive information, which cannot be reviewed by market participants. The IOUs recommend further discussion in the Working Group

A. PG&E 2017-18 Approach

PG&E employs a load projection approach that is integrated across distribution and transmission planning. Consistent with that approach PG&E plans to use the load growth assumptions proposed in the IRP Assumptions and Scenarios ACR and adopted for use in the 2017/2018 TPP for local area studies. For the 2017/2018 forecast PG&E plans to use the following steps to ensure that load growth projections used for distribution planning studies are consistent with the load growth projections used for local area transmission planning studies:

1. Take the annual peak load growth in MW for the PG&E transmission area from the CEC's 2016 Update of the California Energy Demand Forecast, 1 in 2 recurrence interval mid-basecase scenario.
2. Remove estimated transmission level customer growth from the CEC's load growth projection. Current assumption is 10MW per year transmission level customer growth.
3. Work with CEC staff to break out the DERs (DG, LMDR, EV, ES, EE) embedded in the basecase load growth projection.
4. The resultant load growth is turned into a % growth by year, which is then applied to the distribution system's previous year's weather normalized coincident distribution peak to obtain a MW growth by year that is accurately scaled to match most recent distribution system observed loads as a starting point. This scaling is needed for distribution load growth studies because the CEC's IEPR forecast is for the PG&E transmission area and not PG&E's distribution area.
5. Break down the distribution growth forecast by Customer Class based on percent of distribution system total energy usage. This is done because the CEC's and PG&E's definition of industrial and commercial is not the same. The CEC's definition is based on NAICS code while PG&E's definition is based on FERC revenue account to conform with FERC Form 1 classifications.
6. Remove known future loads that have already been entered as adjustments in LoadSEER to avoid double-counting growth for these customers. PG&E has local knowledge of large load increases in an area and uses this information in its distribution planning studies. This is done at the customer class level because the block load adjustments are done at the customer class level. In order to preserve consistency with the projected CEC annual load growth we first remove growth equivalent to the block load from the CEC-based load growth projections.
7. Allocate out the remaining customer class level system load growth to each parcel of land in PG&E's service territory based on our vendor supplied geospatial load allocation model LoadSEER from Integral Analytics. Each parcel in the PG&E's service territory is

first scored for any zoning restrictions and then scored for its attractiveness for future residential, commercial, industrial, or agriculture load growth. Each parcel of land is also mapped to a distribution feeder.

8. After the system load growth has been allocated to each feeder and bank using the geospatial model a load shape is applied to the allocated feeder level load in order to properly reflect the temporal diversity in load between the system, bank and feeder. For example if the system level peak load from the CEC's mid-basecase projection was in August at 5:00 PM the distribution bank peaked in July at 7:00 PM and the distribution feeder peaked in September at 9:00 PM the bank and feeder load shapes will properly reflect local area diversity while still allowing PG&E to reconcile back to the system peak to maintain consistency with the CEC's annual load growth projections.
9. Recall that in step 3, above, PG&E stripped out the embedded DERs from the CEC mid-basecase scenario. In the final load growth forecasting step we reapply the DER projections at the WECC bus level for use in transmission planning studies and at the feeder level for use in distribution planning studies based on the methodologies that are described in the sections below on near-term approaches to allocating DER adoption projections. Like the allocation of load, this involves both an allocation of the system level DER projection and the application of a locational DER specific load shape in order to properly reflect the local impacts of the DER.

The LoadSEER hierarchy contains distribution feeders, distribution banks, distribution planning areas and Western Area Coordinating Council (WECC) busbars. This allows us to consistently aggregate the feeder load forecasts up through banks and distribution planning areas and to link to the transmission planning areas via the WECC busbars which is where the distribution and transmission systems interface.

B. SDG&E 2017-18 Approach

SDG&E has been undergoing a transition in its load growth forecast. In the past, it has used a "bottom-up" approach, using SCADA and smart meter data to compute weather-adjusted peaks for each feeder and substation. The customer requested load additions within SDG&E were applied individually at the feeder and based on the demand of the load addition, the load was either spread out over a ten-year period to establish a base load growth or the requested load was applied to the specific year requested by the customer.

Moving forward, SDG&E will be moving to a "top-down" approach utilizing LoadSEER software from Integral Analytics to apply the corporate forecast and disseminating the growth amongst the feeders using a geospatial analysis, peak loads, total customer consumption, along with traditional economic factors and weather. This corporate forecast directly correlates to the forecast used in the IEPR for load growth at system peak. Where more specific information is available and applicable, SDG&E will reconcile the "top-down" forecast with known growth projects and area specific information to effectively utilize local knowledge to inform the distribution planning efforts.

The forecasting process begins in the late fall and is usually completed by the end of February. The new method of forecasting is being evaluated by SDG&E and will operate in the same time frame for the foreseeable future.

C. SCE 2017-18 Approach

For the 2017/18 cycle, SCE is also working to improve its distribution planning efforts by moving to an approach which incorporates "top-down" econometric and demographic information from the corporate forecast. This corporate forecast correlates to the forecast used in the IEPR for load growth at system peak. SCE will reconcile the "top-down" forecast with known growth projects and area specific information to effectively utilize local knowledge to inform the distribution planning efforts. For the 2017/18 forecast this local area knowledge includes:

1. A 10-year forecast of demand factoring in known development plans, and local economic conditions.
2. An analysis of historical substation load profiles and historical customer load growth in a geographic region to forecast how demand may change due to the customer base. In addition, SCE works with available agricultural, commercial, industrial, and residential development plans to understand projected increases in demand on existing distribution equipment. This projected increase is based on information provided by the developer and historical load profiles of the distribution equipment planned to serve the development.

This local area knowledge will be utilized to develop a forecast at the feeder level. The approach will be utilized in the 2017/18 planning effort to develop the growth forecast.

VI. Proposed Methodology to Disaggregate the Trajectory/Most Likely Scenario to the Circuit Level For Use in Distribution Planning Studies

A. Overview of 2017-2018 Implementation

Although the utilities share a common view of the future, the electrical system, processes, tools and geography are different across each IOU and therefore the current methods for disaggregation differ by utility. To facilitate ongoing forecasting requirements, the joint-IOU working group has agreed that, in the near-term, existing forecasting methods should not undergo a dramatic change. Continuity is an important element of forecasting and must be adhered to for the sake of reliability.

It should be noted that there is increasing uncertainty when disaggregating a forecast to a more granular level, and this is particularly the case with "large and lumpy" non-residential adoption. The long term goals of disaggregation from the working group are likely to involve significant data acquisition, data mining, analysis and testing. Due to the uncertainty involved in any undertaking of this magnitude, careful study and successful testing must be achieved before implementation can begin.

Existing business structures offer support for a system of DER forecasting reliant on the planning studies developed under the IRP and TPP processes. These processes have the benefit of experience, being well-understood and have been tuned to accommodate historical information. They should, therefore, continue to be used in the near-term and each IOU has presented the near term approach to disaggregation to serve as the starting point as we move to the ideal future state. The near term approach and ideal long term approach will be discussed.

B. Energy Efficiency 2017-18 Implementation

Based on each IOUs internal base load forecast methodology, there is a difference between the amount of energy efficiency which is included in the baseline forecast. PG&E's load forecast relies on the IEPR and therefore can allocate AAEE directly whereas SCE and SDG&E use regression based analysis for the underlying load forecast and must determine how much energy efficiency is truly incremental to the baseline forecast. Each IOU's method will be further described below.

1. PG&E Approach for 2017-18

Currently PG&E uses load growth and DER adoption assumptions consistent with the assumptions adopted for use in the contemporaneous CAISO TPP cycle as proposed in the IRP Assumptions and Scenarios ACR. In order to ensure consistency with TPP, PG&E uses the AAEE projections at the WECC busbar level as adopted for use in local planning studies in the TPP (IEPR low-mid AAEE scenario). This methodology has been developed and approved by the CEC, CPUC and CAISO. The WECC busbar level customer class AAEE is allocated to the distribution bank and feeder level based on past adoption rates in the specific locations by customer class. In order to properly reflect the impact of future EE at the bank and feeder level, PG&E allocated out the customer segment level EE based on the load shape for that customer class at the bank and feeder level. The local load shapes are generated from available AMI data.

2. SDG&E Approach for 2017-18

SDG&E plans to continue using the AAEE forecasts in IEPR process to provide a system wide value. This will then be disaggregated on a basis of past adoption rates broken down to customer class segments on each feeder. The most recent adoption behavior will be given the most weight and linearly decrease with time. Each customer class segment on each feeder will be assigned a score based on the recent adoption which will then be applied to the system wide IEPR, mid-energy demand, low-AAEE value.

3. SCE Approach for 2017-18

For SCE, the system wide values are comprised of two components; EE Program savings and Codes and Standards (C&S) savings. SCE's EE Program savings are designed to meet or exceed goals set by the CPUC based on the EE Potential and Goals study and should be utilized for allocation. The C&S portion is directly obtained from both the CEC's Base Model as well as AAEE. Both EE Program savings and C&S savings will be allocated down to the circuit level based on historical energy consumption and the underlying customer type dispersion across the distribution circuits.

C. SRDR 2017-18 Implementation

For all IOUs: If SRDR assumptions are deemed to be appropriate based on prior approval of multi-use applications of SRDR for distribution system reliability and acceptance of the use of SRDR by distribution planning and operations for this purpose, then SRDR should be allocated to distribution feeder based on the actual location of the SRDR resource that is registered with the CAISO in the resource Masterfile.

D. LMDR 2017-18 Implementation

Based on each IOUs internal base load forecast methodology, there is a difference between the amount of LMDR which is included in the baseline forecast. PG&E's load forecast starts with the CEC's mid-basecase projection from the 2016 IEPR update consistent with the load growth assumptions approved for use in the 2017/2018 TPP. For that reason PG&E can directly allocate LMDR from the system level projections to the bank and feeder level. In contrast SCE and SDG&E use an in-house regression based model to produce the underlying load forecast and subsequently must determine how much LMDR is embedded in their baseline forecast in order to deduce what portion, if any, is incremental.

Each IOU's method will be further described below.

1. PG&E Approach for 2017-18:

Starting with the LMDR peak load impacts as estimated in the CEC's mid-baseline projection allocate out the estimated impacts of LMDR first to each SubLap/LCRA for use in transmission planning studies based on the most recent available DR Load Impacts Protocols report (published April 1st of every year). Then allocate out the LCRA level LMDR to bank and feeder level based on the proportion of each feeder's customers who are eligible to participate in each LMDR program. For example, residential TOU impacts for the Greater Bay Area LCRA estimated in the Load Impact Protocols filing would be allocated to banks and feeders in Menlo Park distribution planning area based on the ratio of residential load during peak TOU periods on those feeders to residential load during peak periods in the Greater Bay Area LCRA. Load impacts for commercial TOU, Peak Day Pricing and SmartRate would likewise be allocated from LCRA to bank and feeder using analogous methods. Once this is accomplished the feeder level LMDR is matched with a load shape in order to produce the hourly adoption projection at the feeder level that is needed for the distribution planning models. In order to properly reflect the impact of LMDR at the local bank and feeder level an LMDR load shape is applied to the allocated LMDR LCRA peak load impacts.

2. SDG&E Approach for 2017-18

Using historical adoption data within the service territory, customer propensity ratios will be established at the zip code level and applied to corresponding circuits. More recent local adoption rates will be giving more weight that older rates. Due to the relatively slow projected growth of Demand Response in the service territory, the focus will lie in realigning the circuit-level adoption as enrollment evolves.

3. SCE Approach for 2017-18

The process to estimate the propensity of program enrollment will begin with segmenting customers who are eligible to participate in a specific DR program. Eligible customers will be clustered into groups with similar characteristics, program preferences, etc. The model will consider with the effects of marketing through various channels and different incentive levels to inform disaggregation. The resulting propensity scores will be combined with the average customer ex ante load impacts to disaggregate the LMDR forecast.

E. Distributed Generation 2017-18 Implementation

IOUs generally employ a top-down methodology which allocates a selected system-level forecast for distributed generation (primarily PV) to the feeder level and applies an appropriate load/generation shape, as described below. The IOUs use varying techniques to allocate the system level forecast to feeders including historic adoption trends and customer propensity.

1. PG&E Approach for 2017-18

PG&E’s approach to developing scenarios for geospatial DG technology adoption consists of allocating the system level DG forecast scenarios to distribution feeders based on the probability of technology adoption of customers on each feeder. Customer probabilities of adoption are estimated using statistical methods developed using appropriate feature sets (including but not limited to homeownership, usage characteristics, and location). The allocation model uses these probabilities of adoption, together with estimates of technical potential and system sizes, to allocate the system forecast to each feeder. Once this is accomplished the feeder level adoption projection is matto properly reflect the bank and feeder level impact of future DG adoptions..

2. SDG&E Approach for 2017-18

SDG&E plans to continue using the distributed generation forecasts provided by IEPR process to provide system wide values for large scale DG, including conventional and PV, and small scale PV generation. The small-scale PV generation will be disaggregated on a basis of past adoption rates broken to the circuit level. The most recent adoption behavior will be given the most weight. Each circuit will also be given a maximum adoption value based on the number of meters on the circuit and the forecasted value will approach this maximum asymptotically.

3. SCE Approach for 2017-18

The overall projections of solar photovoltaic (PV) systems will be allocated by first splitting the overall system forecast projections between residential and commercial installations. SCE will allocate the residential and commercial market segments separately. The residential DG allocation is based on two main parts:

1. Generalized Bass Diffusion model, which accounts for the cost of solar PV systems. K-means clustering is used to sort the circuits based on historical rates of adoption and Bass Diffusion is then utilized to estimate allocation and future growth rates for each cluster.
2. Zero Net Energy mandate model, which uses the SCE forecast of new meters which is allocated based on customer segment information

For commercial customers, SCE will rely on historical adoption and economic potential for disaggregation. The commercial customers are grouped by historical usage and North American Industry Classification System (NAICS) code.[9] The system-wide commercial forecast will then be allocated down to the circuit level based on the underlying customer type dispersion across the distribution circuits.

F. Electric Vehicles 2017-18 Implementation

Although several data sources exist which delineate EV ownership by various regions (zip code, county etc.), because there is a disconnect between geography and electric system topology, mapping the locations of all existing EV's at the circuit level remains a challenge. Some additional challenges in the near term include understanding of load shapes and charging patterns for electric vehicles.

1. PG&E Approach for 2017-18

County level EV adoptions are allocated to the feeder level using a 3-step process. PG&E uses a multivariate regression performed on publicly available aggregated zip-code level EV data and Census Block Group level economic and demographic variables. We

[9] The North American Industry Classification System (NAICS) is the standard used by Federal statistical agencies to classify businesses on their primary economic activity. As an example, code 44511 represents supermarkets and other grocery stores.

then apply proportional allocations based upon the number of customers served by each feeder in the census block group. The final step is to allocate the county level 10 year EV count projections, such that the zip, census block group and feeder estimates do not exceed the county's projected yearly EV count, respectively. Once the allocation process is complete, PG&E then assigns an EV load shape to produce hourly profile projections that are need to properly reflect the impact of EV adoption at the bank and feeder level.

2. SDG&E Approach for 2017-18

The data available consists of those customer who have converted to EV rates and those publicly-oriented projects that SDG&E plans to construct. Known large scale projects will be applied to specific location with probability factor applied based on the nearness to the in-service date. Then the remainder of the growth forecast value will be calculated throughout the territory based on extrapolation of existing EV rate conversions, applied geospatially. If a growth forecast becomes available via the IEPR process, it will be used as to pin the total forecasted value based on past customer propensity model minus the known large-scale projects.

3. SCE Approach for 2017-18

The first step is to allocate existing EV's to the circuit based on known locations. Electric Vehicles which are incremental to the existing EV's will be allocated based on historical adoption, customer segment information and peak month energy consumption data. Once the allocation process is complete, SCE then assigns an EV load shape to produce an hourly profile projection that is needed for the distribution planning models. As SCE better refines the relationship between economic/demographic data and a customer's likelihood to utilize an electric vehicle, this model will be refined.

G. Energy Storage 2017-18 Implementation

Energy storage is particularly challenging to allocate to circuits because of the considerable uncertainty in how energy storage may be used in future applications and a significant lack of historical adoption. Therefore, the near term methodologies proposed by the IOUs in this area are subject to more volatility as forecasts and disaggregation will be heavily influenced by the observed patterns of adoption and other changes in policy moving forward.

1. PG&E Approach for 2017-18

PG&E's current approach is to closely monitor energy storage interconnection requests and incorporate county-specific interconnection information into the distribution planning assumptions. Counties in PG&E territory with no energy storage are assigned energy storage installations starting in 2017, scaled to population based on average MW of energy storage per population of other counties, and divided into residential and non-residential based on the average residential/non-residential ratio observed in historical data. Depending on the observed correlation between storage, PV and EV installation, more robust datasets for PV and EV adoption distribution will be used to refine allocation of storage adoption at the county level going forward.

2. SDG&E Approach for 2017-18

Using historical energy storage in the territory, a customer propensity model will be developed using recent adoption rates. The model will focus primarily on zip-code level granularity for the adoption trends. Additionally, using the observable correlation between energy storage and photovoltaic installation, the more robust dataset for PV adoption will be utilized to enhance the still-nascent energy storage dataset to assist in the forecast. If a growth forecast becomes available via the IEPR process, it will be used to pin the total forecast based on past energy storage and photovoltaic adoption rates.

3. SCE Approach for 2017-18

Allocation will be based on three factors: (1) the existing level of energy storage on a given feeder, (2) the amount of additional contracted generation expected for that feeder and (3) the penetration of solar PV on that given feeder. The solar PV penetration is included under the assumption that the primary driver for energy storage investments will be to allow these commercial customers to "firm" the output of their solar PV systems in order to minimize exposure to peak demand charges.[10] [11] [12] SCE has considered methods of allocation, however, at this time the operating characteristics for energy storage are largely unknown. SCE is currently evaluating the ability for energy storage to dependably serve load during peak load times. SCE will incorporate dependable energy storage into future planning cycles.

H. Future State Vision

The Joint IOU's long-term goal is to provide disaggregated DER forecasts to support the distribution planning objective of providing safe, reliable, affordable and clean energy services to customers. These forecasts should leverage available DER and customer data, as well as statistical techniques, to offer the maximum utility for distribution planning. However, different DERs are at different stages of market development, and thus have very different levels of data availability. This means that the statistically appropriate forecast methodology will vary by DER technology and will change over time as data availability increases. Additionally, as the IOUs gain experience in both developing disaggregated DER

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[10] http://www.baker-electric.com/projects-experience/project-profiles-battery-storage/case-study-smart-storage-at-baker-electric/

[11] http://www.princetonpower.com/pdfs/scripps_ranch_cs.pdf

[12] http://www.econotimes.com/Mission-Viejo-business-Franchise-Services-invests-in-solar-plus-energy-storage-to-drastically-reduce-utility-bills-and-eliminate-hefty-demand-charges-221561

forecasts and using them in distribution planning, the IOUs will continue to revisit the forecast methodologies to improve their ability to predict the amount of DERs that will materialize.

In order to achieve the goal of using distribution planning to provide safe, reliable, affordable and clean energy services to customers, the IOUs believe that the forecast methodology for each DER should be tailored to its unique characteristics and context in each IOU's distribution grid. Thus, rather than proposing a single methodology for DER forecasting, the Joint IOUs propose the following principles for disaggregated DER forecasting. These principles will guide the IOUs in evolving the DER forecast methodologies to be appropriate for each DER's level of data availability, market maturity, and impact on distribution planning:

- Utilize statistically appropriate, data-driven methodologies for each DER, customer segment, and level of disaggregation
- Develop approaches to manage uncertainty associated with granular allocation of DER
- Periodically re-assess the modeling approach for each DER as increased adoption leads to better data
- Share best practices and leverage learning process to strive for continuous improvement both in forecasting and in using the forecasts for distribution planning
    - Integrate data from DER industry partners to enhance forecasting accuracy

VII. Conclusion

This document presents the IOUs' proposed approach for DER and load forecasting. The IOUs expect to discuss and receive feedback on this document in the Working Group sessions, to help inform the revised IOU Assumptions and Framework document to be submitted in June.