BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Distributed Energy Resources.	R.14-10-003 (Filed October 2, 2014)

COMPETITIVE SOLICITATION FRAMEWORK WORKING GROUP FINAL REPORT FILED BY SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), PACIFIC GAS AND ELECTRIC COMPANY (U 39-M), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E), AND SOUTHERN CALIFORNIA GAS COMPANY (U 904-G)

JANET S. COMBS
CATHY A. KARLSTAD

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1096
Facsimile: (626) 302-6962
E-mail: Cathy.Karlstad@sce.com

Dated: **August 1, 2016**

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Pursuant to the Administrative Law Judge's Ruling Establishing a Working Group to Develop the Competitive Solicitation Framework, dated March 24, 2016 (Ruling), Southern California Edison Company files on behalf of the Working Group the attached "Competitive Solicitation Framework Working Group Final Report." This filing is made pursuant to a directive in the Ruling to Southern California Edison Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Gas Company.

Respectfully submitted,

JANET S. COMBS
CATHY A. KARLSTAD

/s/ Cathy A. Karlstad

By: Cathy A. Karlstad

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1096
Facsimile: (626) 302-6962
E-mail: Cathy.Karlstad@sce.com

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Competitive Solicitation Framework Working Group
Final Report

August 1, 2016

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Acronyms

AC: Alternating Current
ACR: Assigned Commissioner's Ruling
ADR: Automated Demand Response
ALJ: Administrative Law Judge
A/S: Ancillary Services
BPM: Business Practice Manual
BTM: Behind-the-Meter
BQDM: Brooklyn-Queens Demand Management
CAISO: California Independent System Operator
CCA: Community Choice Aggregator
CEC: California Energy Commission
CHP: Combined Heat and Power
CPUC or Commission: California Public Utilities Commission
CSFWG: Competitive Solicitation Framework Working Group
CVR: Conservation Voltage Reduction
DC: Direct Current
DER: Distributed Energy Resource
DERMS: Distributed Energy Resource Management Systems
DG: Distributed Generation
DLC: Direct Load Control
DPAG: Distribution Planning Advisory Group
DPP: Distribution Planning Process
DR: Demand Response
DRAM: Demand Response Auction Mechanism
DRAMP: Demand Response Aggregator Managed Portfolio
DRP: Distribution Resources Plan
ED: Energy Division
EE: Energy Efficiency
ERRA: Energy Resource Recovery Account
ES: Energy Storage
EV: Electric Vehicle
FLISR: Fault Location Isolation and Service
GHG: Greenhouse Gas
GRC: General Rate Case
ICA: Integration Capacity Analysis
IDER: Integrated Distributed Energy Resources
IE: Independent Evaluator
IFOM: In-Front-of-Meter
IOUs: Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Southern California Gas Company
IPE: Independent Professional Engineer
IRP: Integrated Resources Plan
LCBF: Least Cost, Best Fit
LCR: Local Capacity Requirements
LGP: Local Government Partnership
LMP: Locational Marginal Prices
LMR DR: Load Modifying Resource Demand Response
LNBA: Locational Net Benefit Analysis
LSE: Load-Serving Entity
LTPP: Long-Term Procurement Plan
MP: Market Participant
M&V: Measurement and Valuation
MUA: Multi-Use Applications
NDA: Non-Disclosure Agreement
NEM: Net Energy Metering
NMV: Net Market Value
NPV: Net Present Value
NQC: Net Qualifying Capacity
ORA: Office of Ratepayer Advocates
PG&E: Pacific Gas and Electric Company
PRG: Procurement Review Group
PRP: Preferred Resources Pilot
PV: Photovoltaic
RA: Resource Adequacy
REC: Renewable Energy Credit
RECC: Real Economic Carrying Charge
RICA: Renewable Integration Cost Adder
RFO: Request for Offers
RPS: Renewables Portfolio Standard
RTO: Regional Transmission Organization
SCADA: Supervisory Control and Data Acquisition
SCE: Southern California Edison Company
SDG&E: San Diego Gas & Electric Company
SoCalGas: Southern California Gas Company
T&D: Transmission and Distribution
TPA: Third Party Aggregators
TPP: Transmission Planning Process
VAR: Volt-Ampere Reactive
Working Group: Competitive Solicitation Framework Working Group

Introduction and Background

On February 26, 2016, the Assigned Commissioner and Administrative Law Judge (ALJ) jointly issued a Joint Assigned Commissioner and Administrative Law Judge Ruling and Amended Scoping Memo (Scoping Memo) for the Integrated Distributed Energy Resources (IDER) proceeding (R.14-10-003).[1] Among other changes, this Scoping Memo broadened the scope of the IDER proceeding to include a determination of how to acquire the resources required to fill the needs identified through the Distribution Resources Plan (DRP) proceeding (R.14-08-013 et al.). The Scoping Memo and subsequent Ruling discussed below included an initial focus on competitive solicitations and development of a competitive solicitation framework targeting the reliability needs within the areas identified by the Integration Capacity Analysis (ICA) and Locational Net Benefits Analysis (LNBA) performed in the DRP proceeding. In order to facilitate the development of a competitive solicitation framework, the Scoping Memo identified the need to establish a competitive solicitation framework working group (CSFWG or Working Group). The Scoping Memo also stated that a workshop would be held to discuss the lessons learned from past competitive solicitations. The workshop was held on March 28, 2016.

On March 24, 2016, the ALJ issued an Administrative Law Judge's Ruling Establishing a Working Group to Develop the Competitive Solicitation Framework (Ruling).[2] This Ruling provided details on the scope and schedule for the CSFWG. In particular, the Ruling identified seven elements of a competitive solicitation framework, and directed: a) the Working Group to develop a status report and a final report; b) that each report shall describe the activities of the Working Group and the progress of the Working Group in attaining each of the seven elements listed in this Ruling; and c) that each report shall identify consensus issues and disputed issues, positions of parties on disputed issues, and a recommended plan for addressing each disputed issue, *e.g.*, through further Working Group discussions, comments on the record, etc. These elements, listed below, were the focus of the CSFWG discussions.

A. Defining the services to be bought and sold within the identified areas. The definitions should include details on the expected reliability and other performance requirements, as well as any constraints, not previously determined in R.14-08-013, on how distributed energy resources (DERs) can meet the identified need.
B. Development of methodologies to count services provided and ensure no duplication with procurement in other proceedings, *i.e.*, ensure these resources are incremental to existing efforts and avoid double-counting of resources.
C. Development of solicitation rules or principles such as constraints on procurement, *e.g.*, floors and ceilings on volume procured, price paid, etc.
D. Development of solicitation oversight needs, *e.g.*, procurement plans, procurement review groups, etc.
E. Development of solicitation evaluation methodology to include the valuation of any deferred distribution system upgrade.
F. Development of solicitation pro forma contract(s).

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[1] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M158/K886/158886810.PDF.
[2] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M159/K671/159671058.PDF.

G. Development of outreach plans to ensure robust participation in the competitive solicitations.

Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), and Southern California Gas Company (SoCalGas) (jointly, the IOUs), as representatives of the CSFWG, were tasked with filing a status report by June 1, 2016, and a final report by August 1, 2016.

Membership for the CSFWG was solicited through the IDER proceeding service list, and a kick-off call was held on April 8, 2016. Once the group was established, four weekly in-person meetings were held to discuss the seven elements of a competitive solicitation framework identified in the Ruling. The seven elements were grouped together to allow for all topics to be covered across the span of the four meetings. The schedule and topics covered for each meeting are listed in Table 1.

Table 1: Initial Working Group Meetings and Topics

Meeting Date	Working Group Topic	Element from Ruling
4/14/16	Technical/Services	a. Defining the services to be bought and sold within the identified areas. The definitions should include details on the expected reliability and other performance requirements, as well as any constraints, not previously determined in R.14-08-013, on how DERs can meet the identified need.
4/22/16	Process & Rules	c. Development of solicitation rules or principles such as constraints on procurement, *e.g.,* floors and ceilings on volume procured, price paid, etc.
		d. Development of solicitation oversight needs, *e.g.,* procurement plans, procurement review groups, etc.
		g. Development of outreach plans to ensure robust participation in the competitive solicitations.
4/28/16	Valuation and Planning	b. Development of methodologies to count services provided and ensure no duplication with procurement in other proceedings, *i.e.,* ensure these resources are incremental to existing efforts and avoid double-counting of resources.
		e. Development of solicitation evaluation methodology to include the valuation of any deferred distribution system upgrade.
5/3/16	Contracts	f. Development of solicitation pro forma contract(s).

In addition to the four in-person meetings, two teleconference meetings were held to confirm consensus items, identify items for follow-up, identify items that are out-of-scope, and

to determine next steps for the CSFWG. These calls were held on May 11 and May 18, 2016. The results of the in-person and teleconference meetings were presented in the Competitive Solicitation Framework Working Group Status Report (Status Report) filed on June 1, 2016.

After the development of the Status Report, two more meetings were held with the full CSFWG; one focusing on reliability and performance requirements and one focusing on oversight. As part of these meetings, the CSFWG decided that the formation of sub-teams was the appropriate path forward. These sub-teams, listed below in Table 2, became the focus of the CSFWG, developing recommendations that were brought back to the full CSFWG for review and determination of whether there was consensus. The topics, deliverables, and membership of the various sub-teams were confirmed during the June 23, 2016 CSFWG meeting. The sub-teams were convened and developed recommendations during the weeks of June 27 and July 4, 2016. The sub-teams' recommendations were then circulated to the full CSFWG on July 11, 2016, posted at http://drpwg.org/sample-page/ider/. The full CSFWG was reconvened on July 14, 2016, at which time each sub-team presented their recommendations to the full CSFWG for review and consensus identification.

Table 2: Sub-Teams

Sub-Team	**Element**	**Previous CSFWG Meeting**
1a. Definition of Basic Distribution Services + Attributes **1b. Resource Performance + Measurement**	a. Defining services to be bought and sold within identified areas. The definitions should include details on expected reliability and other performance requirements, as well as constraints, not previously determined in R.14-08-013, on how DERs can meet identified need.	1st meeting
2a. Additional Services + Valuation **2b. Valuation Criteria**	e. Development of solicitation evaluation methodology to include valuation of any deferred distribution system upgrade.	1st + 3rd meetings
3a. Distribution Loading Order	N/A	1st meeting
3b. Double-Counting; Incrementality	a. Defining services to be bought and sold within identified areas. Definitions should include details on expected reliability and other performance requirements, as well as any constraints, not previously determined in R.14-08-013, on how DERs can meet identified need. b. Development of methodologies to count services provided and ensure no duplication with procurement in other proceedings, *i.e.*, ensure these resources are incremental to existing efforts and avoid double-counting of resources. c. Development of solicitation rules or principles such as constraints on procurement, *e.g.*, floors and ceilings on volume procured, price paid, etc.	1st + 3rd meetings
4a. Timeline **4b. Spectrum of Oversight**	c. Development of solicitation rules or principles such as constraints on procurement, *e.g.*, floors	2nd meeting

4c. Roles of DRP, DPP, and Linkages	and ceilings on volume procured, price paid, etc. d. Development of solicitation oversight needs, *e.g.*, procurement plans, procurement review groups, etc.	
5. Pro-Forma Contracts (including reliability + performance requirements)	f. Development of solicitation pro forma contract(s).	4th meeting
6. Customer Outreach	g. Development of outreach plans to ensure robust participation in the competitive solicitations.	2nd meeting
7. Non-IOU Load-Serving Entities (LSEs)	N/A	1st meeting

The following list of organizations, or in some instances individuals, participated in at least one Working Group meeting.

Advanced Microgrid Solutions
Alcantar & Kahl
Barkovich & Yap
Bloom Energy
California Energy Commission (CEC)
California Energy Efficiency Industry Council (CEEIC)
California Independent System Operator (CAISO)
California Large Energy Consumers Association (CLECA)
California Public Utilities Commission (CPUC or Commission)
Clean Coalition
Comverge
CPower
Earthjustice
EnergyHub
EnerNOC
Enphase
Global Energy Markets
Goodin, MacBride, Squeri & Day, LLP
ICF International (ICF)
Independent Energy Producers Association (IEPA)
John Nimmons & Associates, Inc.
Johnson Controls Inc.
Karey Christ-Janer
Marin Clean Energy
Natural Resources Defense Council (NRDC)
Nexant
NRG
Office of Ratepayer Advocates (ORA)
PG&E
Port of Long Beach
SDG&E
Sierra Club
SolarCity
Solar Energy Industries Association (SEIA)
SCE
SoCalGas
Stanford University
Stem
Strategy Integration
The Energy Coalition
Vote Solar
World Business Academy

Summary of Results

A summary of the status for each element included in the Scoping Memo and Ruling is provided in Table 3. The status of the CSFWG efforts were categorized into elements which reached preliminary consensus, non-consensus with clear recommendation(s), and non-consensus without clear recommendations. It is the expectation of the CSFWG that parties will be allowed to comment on the recommendations included in this report, and summarized in the table, to develop a record for CPUC consideration.

Table 3: Consensus Summary

Element	Consensus	Non-Consensus, Clear Recommendation(s)	Non-Consensus, Clear Recommendation(s) Need to be Developed
1. Services	X		
2. Double-Counting/Incrementality			X
3. Rules & Principles			X
4. Oversight		X	
5. Valuation	X (components)		X (transparency)
6. Pro Forma	X (types of changes)		X (technology neutral)
7. Outreach	X (market)	X (customer)	

Elements

This section provides the details of the discussion for each element identified in the Scoping Memo and Ruling as being within scope of the CSFWG. Each element includes the items identified as consensus in the Status Report (where applicable), the recommendations from the associated sub-team, identification of whether there was consensus, and any additional discussion.

A. Services

Summary of Progress

The CSFWG reached consensus on potential distribution services: energy, capacity, voltage, and incremental data. The sub-team on this topic also developed illustrative examples of needs and the associated attributes that would be procured. The need for contingency planning was identified, but not resolved.

Consensus Items from Status Report

1. *Potential distribution services that DERs may be able to provide to address a distribution grid need:* Energy (up/down), Capacity (up/down), and Voltage/Volt-Ampere Reactive (VAR) services (up/down) were identified as the foundational services, but as noted elsewhere, the sourcing process may be procuring a solution that is a high-value application of these basic services.

2. *Detailed attributes to these services:* Will depend on the specific needs of the system in a particular location, which will be identified and developed in the DRP proceeding.

3. *Data as a Service:* Third-party DER device providers proposed that data being gathered from DER devices, that is incremental to data required for safe and reliable operation of the distribution grid, has value and in some cases could be provided as a service. The group agreed, but did not determine in what cases this would apply.

Recommendation from Sub-Team 1 and 2.a

The Working Group has proposed a set of service definitions and attributes based on the electric utilities' needs as derived through their planning process along with DER market participants' input into possible solutions to the utilities' distribution system needs. The service definitions described encompass different types of services that DERs could provide and capture the corresponding specific attributes which are dependent on location, timing, level of service, and availability of the DER. These services and attributes for each DER will be measured during the commercial relationship of the utility and the DER provider by testing and visibility mechanisms to ensure that the reliability of the DER service for the customers is assured, and that a DER is readily available to provide distribution services with the same level of certainty as a "wires" solution, although the level of service may be measured and defined differently than a traditional wires solution. The recommendations of this sub-team were considered consensus at the final CSFWG meeting. The sub-team's recommendations are included in this section, with the illustrative examples included in Appendix 2.

Distribution Grid Needs

The electric utilities' distribution planning process evaluates and specifies projects to ensure the availability of sufficient capacity and operating flexibility for the distribution grid to maintain a reliable and safe electric system. Electric utility distribution planning engineers utilize: (1) forecasts of electric demand; (2) power-flow modeling tools to simulate electric grid performance under projected conditions to forecast distribution capacity and voltage requirements; and (3) engineering expertise to identify and develop distribution capacity and voltage management additions that meet forecast conditions that address identified distribution capacity and voltage requirements, including safety and reliability deficiencies.

The electric distribution system must be planned for transmission, substation and circuit (*e.g.*, feeder) capability that ensures:

A. Substation and distribution facilities are not loaded beyond safe operating limits;

B. Voltage supplied to the customers is within limits as required by CPUC Rule 2 and industry electric system reliability standards; and

C. Reliability for customers is assured and improved over time.

As a result of this planning process, electric utilities identify and implement least cost, best fit (LCBF) solutions for the distribution system to provide safe and reliable electric service for all customers. These distribution solutions may take the form of implementing a traditional utility "wires" or a "non-wires" solution, such as a DER portfolio, a portfolio that can be comprised of similar or various DER technologies operating in a coordinated manner, that can defer a traditional utility "wires" solution for a number of years.

For DERs to successfully provide distribution services, they must meet the same technical and operating standards as the rest of the distribution system such that when DERs are interconnected, they do not impact the safety and reliability of the distribution grid. In addition, DERs providing distribution services must also operate in a manner that aligns with the local distribution area's electrical loading attributes to ensure safe and reliable distribution service.

Solicitations developed by IOUs requesting DERs to provide distribution services will specify at a minimum the following primary types of guidance to bidders, which are further described in the following subsection:

i. **Services:** DERs will be solicited to provide some combination of distribution capacity, voltage, and reliability/resiliency services.

ii. **Attributes:** DERs will need to be able to deliver specified services reliably at very precise locations, at specific times, and in predictable amounts.

iii. **Performance Requirements:** DERs will be expected to integrate with system operational needs and deliver verifiable performance.

Principles for Defining Distribution Services and Associated Attributes

In developing the definition for distribution services and the associated attributes describing the characteristics of those services, a common set of principles was developed and agreed upon by the CSFWG. Specifically, the following four principles were shared with the CSFWG that formed the foundation and importance of defining the details around distribution services. These four principles were:

1. Location of where distribution service is provided

2. Timing of when distribution service is provided

3. Level of DER service provided

4. DER availability and assurance of ability to provide

Location of where Distribution Service is Provided

The distribution system will require locational specific distribution services to address a constraint on its system. For example, a distribution capacity deficiency on a substation transformer may be met with DERs interconnected off that particular substation transformer's low side connection or off one or multiple distribution feeders interconnected onto that substation transformer. However, a deficiency on a certain section of a distribution feeder will require that DERs be interconnected only on the overloaded section to ensure that overload issue is addressed.

Timing of When Distribution Service is Provided

The distribution system has varying needs that can occur at various times within a day, month, or season. For example, the electric demand loading profile of a distribution feeder may reveal that high loading may occur for a few hours in the evening during the summer months, while another distribution feeder may exhibit high loading for a few hours in the early afternoon during the summer months.

Level of DER Service Provided

The level, magnitude or size of DER service, output or response matters when ensuring the distribution system can continue to operate safely and reliably to serve customers. Not achieving the full response required from DERs providing distribution capacity or other services can result in a short fall of capacity on the distribution system. This shortfall can result in equipment overloads and/or inadequate voltage levels that affect electric service for end users and their equipment. Conversely, DER responses that result in higher than required DER output can lead to thermal overloads and/or voltage levels above acceptable service levels which can lead to equipment damage on the customer side of the meter.

DER Availability and Assurance of Ability to Provide

For DERs to successfully provide distribution services, they must meet the same expectations as the rest of the distribution system. These DERs must be readily available to provide distribution services with the same level of certainty as a "wires" solution can provide. The agreement between the DER and the IOU must include provisions to ensure that not only the DERs will be available, but that these DERs are capable of producing and then produce the desired level of output or provide the desired level of service at the right times and for the right time durations.

Distribution Services Definitions

Considering these principles, the CSFWG was able to reach consensus on three key distribution services that DERs can provide, which may result in deferral of distribution capital costs. Specifically, these three distribution services are: 1) Distribution Capacity, 2) Voltage Support, and 3) Reliability and Resiliency.

Distribution Capacity

Distribution Capacity services are defined as a load modifying or supply services that DERs provide via the dispatch of power output (megawatts, MW) for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure. These Distribution Capacity services can be provided by a single DER resource and/or an aggregated set of DER resources that reduce the net loading on a specific distribution infrastructure location coincident with the identified operational need in response to a control signal from the utility.

Examples of traditional "Wires" equipment that currently support providing this type of service include, but are not limited to are, transformers, overhead and underground line conductors, circuit breakers, and line and substation switches.

Voltage Support

Voltage support services are defined as a substation and/or feeder level dynamic voltage management services provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems. DERs providing these services will be delivering or absorbing real or reactive power (VAR) or a combination thereof to ensure the voltage is within Rule 2[3] limits.

Examples of traditional "Wires" equipment that currently support providing this type of service include, but not limited to, fixed or switchable capacitors, fixed or switchable variable voltage regulators, overhead and underground line conductors, substation load tap changers, and reactors.

Reliability (Back-Tie)

Reliability (back-tie) services are defined as load modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations. These Reliability back-tie services can be provided by a single DER resource and/or an aggregated set of DER resources that are able to reduce the net loading on specific distribution infrastructure coincident with the identified operational need in response to a control signal from the utility.

Examples of traditional "Wires" equipment that currently support providing this type of service include, but are not limited to are, circuit breakers and relays, reclosers and recloser controllers, switches, sectionalizers, fault interrupters, Supervisory Control and Data Acquisition (SCADA), and Fault Location, Isolation and Service Restoration (FLISR).

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[3] CPUC Rule 2 describes electric service requirements, which includes the acceptable secondary voltage ranges of electric service to electric customers.

Resiliency (Microgrid)

Resiliency (Microgrid) services are defined as load modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations. In addition, this service will also provide power to islanded end use customers when central power is not supplied and reduce duration of outages. These resiliency services can be provided by a single DER resource and/or an aggregated set of DER resources that are able to reduce the net loading on specific distribution infrastructure coincident with the identified operational need in response to a control signal from the utility. In a microgrid application it is necessary for a system to match generation to load while maintaining voltage, frequency, power factor and power quality within appropriate limits. This requires an isochronous supply resource.

Examples of traditional "Wires" equipment that currently support providing this type of service include, but are not limited to are, circuit breakers and relays, reclosers and recloser controllers, switches, sectionalizers, fault interrupters, SCADA, FLISR, and Distributed Energy Resource Management Systems (DERMS).

Distribution Services Attributes

Attributes of the needed distribution services further describe the required response from a DER. These distribution service attributes include: 1) locational specificity as to where on the distribution system that the desired DER response is needed, 2) level or magnitude of the DER response that is required, 3) timing and duration of when the DER response is desired, and 4) DER availability and assurances of the ability to provide the services.

Distribution Services Performance Requirements

To ensure that DERs are able to provide distribution services in a safe and reliable manner, a DER will be required to meet certain performance standards that can be measured by the utility. Depending on the location and attributes of the local distribution area where DERs are providing these distribution services and the type of DER, these performance requirements may vary. However, these DER performance requirements will include at a minimum the following:

- System Availability
- Data Availability
- Response Time Following a Utility Command Signal
- Quality of Response (*e.g.*, measurement if DER provided required output for specified duration and frequency as defined by agreement)

System Availability

For DERs to successfully provide distribution services, DERs must be readily available to provide distribution services with the same level of certainty as a "wires" solution can provide. The agreement between the DER provider and the IOU must include provisions to ensure that

not only will the DERs be available, but that these DERs are able to and actually produce and provide the desired level of output or service at the right times and for the right time durations. To ensure DER availability, the utility will require that the DER developer meet certain pre-commercial milestones during the DER development stage, as well as require periodic testing prior to and during the delivery term of the DER output to gain confidence that the desired output is available to provide distribution services.

These pre-commercial milestones will involve the DER provider submitting scheduled progress reports on the status of the construction of DERs and associated equipment that are needed to provide the contracted distribution services.

Periodic DER testing may be scheduled throughout the term of the DER distribution service agreement, which would include testing prior to approving the DERs for commercial service, as well as prior to the months leading up to when the distribution services from the DERs would be required.

Subject to the DERs performance with its pre-commercial milestones, as well as during its periodic testing and operation during a distribution services event, the utility will need to evaluate the DERs availability during these events as well as its overall performance. If the DERs performance is not satisfactory, the utility may be required to implement a contingency plan of deploying its alternative "wires" solution if the DERs are not able to demonstrate the availability or required levels of operational performance to provide these distribution services. Figure 1 illustrates and example of how the testing may be scheduled for DERs providing these distribution services.

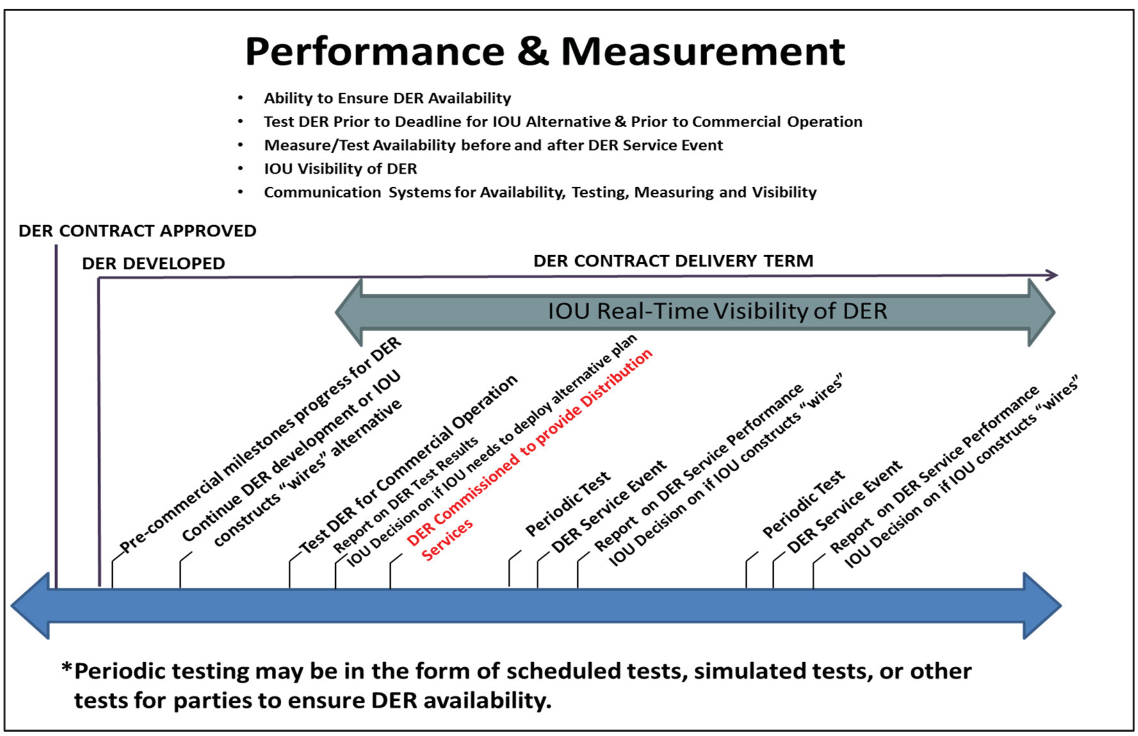

Figure 1: Illustration of Testing for DER Availability and Performance

Data Availability

The utility would require visibility into the availability and ability of the DER, which includes information around when the DER is partially or fully unavailable to deliver output, as well as the current operating state of each of the resources (*e.g.*, state of charge for energy storage resources) within the DER. This may require additional communication infrastructure to be deployed by the utility to obtain this operational visibility into the DER.

Operationally, the utility may need to build new capabilities in forecasting, monitoring, and grid resource management to enable higher penetration of DERs and provide grid services. Forecasting compresses to near real-time to support coordinated transmission and distribution grid planning, control system algorithms, and decision implementation. Advanced monitoring for real-time situational awareness, power quality awareness, distribution load flow analysis and accurate monitoring requires enormous levels of data collection from individual circuits and distributed energy resources at more frequent intervals than before. New predictive capabilities provide the utility with data-driven insights to understand the local impact of distributed energy resources.

Response Time following a Utility Command Signal

The utility will require a timely response following a utility command signal for DERs to provide the desired output to achieve safe and reliable service. Operational communication requirements are evolving based on a more highly distributed power system. The increasing need is for highly available, low latency[4] fiber networks to link substation and control center operations, as well as robust, secure wireless field area networks to support distribution automation, mobile field force automation, and DER integration leveraging electric utility's existing multi-tier smart metering communication system. The latency between utility command signals to actual operation of DERs will be a metric that will be included as one of the DER performance requirements that are providing distribution services.

Depending on the type of distribution service that the utility is procuring, the utility may require DERs to respond within a few seconds, or faster, for some services such as resiliency (microgrid) or voltage support services. Other services may provide a longer lead time following a utility command signal, such as for distribution capacity or reliability (back-tie) support, where the DER may be asked to respond within 30 minutes following an event to ensure that equipment loadings are reduced.

In addition, depending on the type of monitoring and control requirements that the utility may require for certain locations on the grid, these performance requirement may also include the measuring the utility's ability to control the DERs providing these services.

Quality of Response

The quality of the DER response will be measured to ensure the required output amount, duration and frequency of the DER response was within the desired levels to ensure safe and

[4] Latency refers to the time from the source sending a voice/video/data packet to the destination receiving it.

reliable electric distribution service. Some of the metrics the utilities may use to measure the quality of DER response include, but are not limited to:

- DER Readiness & Assurance – Measure the time between when a utility command signal is issued and when a DER response is provided following a utility command signal. Additional visibility and monitoring equipment may be required by the utility to measure and confirm that DERs are responding timely and with the desired amount of output specified.

- Distribution Services Effectiveness of DER Output – Measure the effectiveness of coordinated DER dispatch/scheduling to provide distribution services, such as mitigating projected equipment overloads on the distribution grid. Comparative analysis will be performed evaluating projected equipment loading levels against actual equipment loading levels. Specifically, this evaluation will compare equipment loadings "before" and "after" the sourced DERs are dispatched to understand the technical effectiveness of the sourced DERs. Example data that would be needed to develop metrics: Circuit simulation data, SCADA data, Smart meter data, DER operational data, etc.

- Distribution Services Effectiveness of DER Output Time Duration – Measure duration of time that DERs are able to provide required output. Identify if there are any variations in output during the duration of the desired time period that impact the safety and reliability of electric service for all end users. Example data that would be needed to develop metrics: SCADA data, Smart meter data, DER operational data, etc.

The question of whether fossil-fueled distributed generation resources are eligible to participate in a distributed resource solicitation was discussed in the Working Group. Parties supporting fossil fuel eligibility pointed to a February 5, 2015 Assigned Commissioner Ruling (ACR) in the DRP proceeding indicating fossil-fueled distributed generation resources could be eligible to participate in a distributed resource solicitation. Parties opposing the eligibility of fossil-fueled distributed generation resources noted that Public Utilities Code Section 769, the enabling legislation for distribution resource plans, specifically defines distributed resources as "distributed renewable generation" and therefore excludes conventional distributed generation under well-established principles of statutory interpretation and that the ACR in the DRP proceeding is inconsistent with the unambiguous statutory requirements of Public Utilities Code Section 769. Parties agreed that the issue of eligibility of fossil-fueled distributed generation resources is a legal question beyond the capacity of this Working Group and should be resolved in a decision by the full Commission.

Part of sub-team 2 discussed additional services that could be procured. The sub-team, and the CSFWG, did reach consensus that there could be data provided above and beyond a minimum requirement, which could be a service. Other than service 1 in Table 4, there was not consensus reached in the sub-team, nor in the CSFWG meeting. The recommendations are included for future consideration.

Table 4: Additional Services

#	Additional Service	Description/example	Discussion
1	Grid visibility and situational intelligence	Measured conditions at the grid edge available second-by-second	Consensus additional service when data is not otherwise required
2	Reactive power support	Provided needed reactive power	Non-consensus. Disagreement over whether there is value beyond voltage regulation.
4	Conservation Voltage Reduction (CVR) benefits	Improved energy savings in a utility's CVR program due to smart inverters	Non-consensus. Definition of service may need to be developed further.

This sub-team also discussed the topic of societal net benefits and reached consensus, in the context of a DER providing services vs. benefits, that societal benefits (and costs) are more properly classified as a qualitative net benefit that would be considered on a qualitative basis, as applicable, as part of the bid evaluation/selection process rather than being evaluated quantitatively as a procured and compensated service. The line item for societal net benefits in the valuation section is the result of that discussion.

Additional Discussion

During the final CSFWG meeting, as well as in written form after the meeting, various parties provided additional comments on this topic. The additional comments did not change the consensus on the recommendations, but are included for completeness.

- Contingency plans and whether or not DERs could, or should, be part of a contingency plans was included in the original recommendation, but additional discussion occurred. This discussion included the detailed topics below:
  - Timing of the contingency plan: operational vs. pre-operational
  - Process for selecting contingency DERs
  - The lack of spot markets for distribution deferral resources
  - Industry use cases and business models need to be factored in
  - Potential for changing distribution system needs
  - Utility to develop contingency plan or market to develop as part of bids?
- A recommendation to modify the language from "must meet the same technical and operating standards as the rest of the distribution system" to "must meet their performance requirements so that typical operational and reliability standards are maintained."
- A discussion of the term of the service as an attribute could be merited.

B. Double-Counting

Summary of Progress

The CSFWG discussed the topic of ensuring resources are incremental and not double-counted, but no consensus was reached. Five different frameworks to accomplish this were developed and are included in this report.

Recommendation from Sub-Team 3.b

In initial discussions, the CSFWG determined that two key issues associated with this procurement are whether these resources are incremental to existing efforts, and how to avoid double-counting of resources. This was the focus of sub-team 3.b and the recommendations of that sub-team are provided in this section. Five options were presented, and there was no consensus for a recommendation within the full CSFWG. There are some common themes across the five, described below.

The sub-team proposed three principles, listed below, to guide their discussion (though not all sub-team members support these principles as the appropriate starting place for this discussion). Despite not reaching consensus on these items, they are being included for future consideration.

1. An incremental DER will provide an attribute (aka service) that was not included in the planning assumptions used by the distribution planning engineer when determining if a traditional infrastructure investment is needed to ensure continued safe and reliable operation of the distribution grid.

2. Establishing reasonable planning assumptions is a critical first step towards identifying which DERs are able to provide incremental attributes. Appropriate growth scenarios and/or forecasts for analysis of DER deployment is identified to be addressed within Track 3 of the DRP proceeding.

3. Because of the complexity of this topic and the fact that the distribution location-specific planning assumptions are unknown at this time, the sub-team agreed on the goal of understanding the pros/cons of each identified method for assessing incrementality instead of trying to achieve consensus on one best solution.

The participants in the sub-team and CSFWG identified a number of different frameworks for ensuring resources are incremental. Each framework takes a different approach to address the question of incrementality.

Potential Framework Number 1

Potential Framework Number 1 was proposed by one CSFWG member and discussed at length during the sub-team meetings.

Step 1: IOU identifies a need for incremental attributes on a particular circuit (aka at a specific location) based on reasonable planning assumptions. See Figure 2 below. In this figure, a 24 hour load profile is shown, wherein the load is projected to exceed the

conductor's thermal rated capacity during the hours 3:00-8:00 pm and then again from 9:00-10:00 pm. The organic DER growth is illustrated as the difference between the dotted orange line and the dashed blue line (orange area under the curve). For this example, the incremental DERs are shown as the difference between the dashed blue line and the thermal capacity shown as a red line (the green area under the curve represents incremental DER needs). I n this example, if a competitive solicitation were to procure the DERs in the orange region, the need (*i.e.*, the blue area) would still remain, causing the thermal capacity to be exceeded.

Step 2: IOU issues a solicitation seeking DERs to provide the needed attributes. The solicitation includes material that will discuss the DER attributes included in the planning assumptions.

Step 3: Bidders provide offers for new DER(s) or new DER services to provide the attributes sought after in the solicitation. A pre-determined set of questions may guide the bidder's analysis of whether the offer was included in the planning assumptions or not. See Table 5 below (for example purposes only because planning assumptions are unknown at this time).

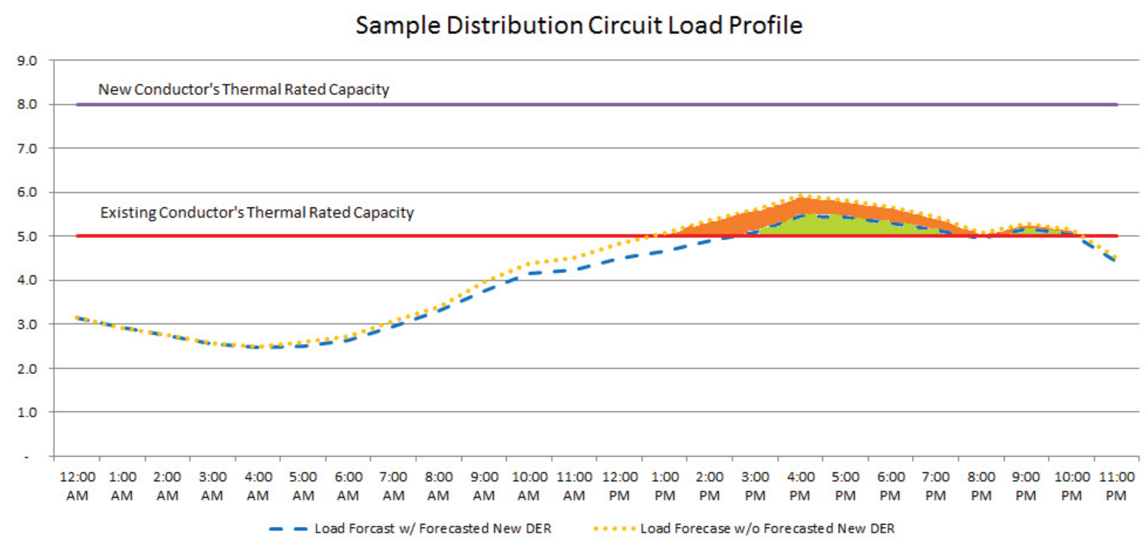

Figure 2: Illustration of Forecasted DERs (Orange) and Resultant Need (Green)

Below is as an example of the types of questions that might guide the determination of whether DER attributes included in an offer are incremental. These questions are based in part on the assumptions identified in Navigant's "Energy Efficiency Potential and Goals Study for 2015 and Beyond,"[5] and on input from the sub-team. Parties would need to develop a similar list of questions based on the actual planning assumptions that are used to determine the need being met by a particular solicitation. Some of these questions may or may not be relevant depending on the actual planning assumptions used in a particular distribution planning cycle, but are

[5] http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=4033.

intended to provide an example of the types of questions that might be helpful in determining whether a DER is providing incremental attributes.

Table 5: Framework 1 Incrementality Questions[6]

Energy Efficiency (EE)	**Demand Response (DR)**	**Photovoltaics (PV/)Wind**	**Energy Storage (ES)**	**Electric Vehicles (EV)**
Is your program part of an IOU's current EE program portfolio or similar to any program in IOU's current EE portfolio?	Is your program part of IOU's current DR program portfolio or similar to any program in IOU's current DR program portfolio?	Is your program or project a new technology? If not, does your program or project increase saturation and/or expand market potential for the existing technology?	Is your program or project a new technology? If not, does your program increase saturation and/or expand market potential for the existing technology?	Is your program part of IOU's Electric Vehicle-Grid Integration (VGI) program? If so, please explain how your program is incremental.
Is your program a new technology or measure? If not, does your program increase saturation and/or expand market potential for the existing technology or measure?	Is your program a new technology? If not, does your program increase saturation and/or expand market potential for the existing technology or measure?	Is your program or project targeting a hard-to-reach market which has not been addressed by existing programs?	Is your program or project targeting a hard-to-reach market which has not been addressed by existing programs?	Is your program a new technology? If not, does your program increase saturation and/or expand market potential for the existing technology or measure?
Is your program targeting a hard-to-reach market which has not been addressed by	Is your program targeting a hard-to-reach market which has not been addressed by	Does your program or project change how existing equipment is operated rather than provide new equipment?	Does your program or project change how existing equipment is operated rather than provide	Please list any federal or state EV grant, credit or incentive you have applied for and any grant, credit or

[6] Understanding that these are examples, one CSFWG member expressed some concern with the questions, particularly as they relate to photovoltaics and energy storage. A more appropriate question for those technologies may instead be, "Would this DER project be built or operated to meet the need of the solicitation if this solicitation had not been issued?" The questions relating to new technology and listing existing incentives are especially concerning as what seem like gating criteria.

Energy Efficiency (EE)	**Demand Response (DR)**	**Photovoltaics (PV/)Wind**	**Energy Storage (ES)**	**Electric Vehicles (EV)**
existing programs?	existing programs?		new equipment?	incentive you have received for your program.
Is your program targeting an area that has not been addressed by existing programs?	Is your program targeting an area that has not been addressed by existing programs?	Is your program/project targeting an area that has not been addressed by existing programs?	Is your program/project targeting an area that has not been addressed by existing programs?	Is your program/project targeting an area that has not been addressed by existing programs?
Is your program related to a measure defined in the Database for Energy Efficiency Resources (DEER) and Frozen Ex Ante (FEA) databases? If so, please explain how your program is incremental.	Have you ever submitted a DR application to an IOU? If so, was your application approved or denied?	Have you ever submitted a PV/wind interconnection application to an IOU? If so, was your application approved or denied?	Have you ever submitted an ES interconnection application to an IOU? If so, was your application approved or denied?	Have you ever entered into, or are you currently engaged in, a contractual relationship with an IOU for an EV program?
Does your program achieve savings above and beyond that which is required through federal and state Codes and Standards? If not, does your program target customers who probably would not have complied with code?	Have you ever entered into, or are you currently engaged in, a contractual relationship with an IOU for a DR resource?	Have you ever entered into, or are you currently engaged in, a contractual relationship with an IOU for a PV/wind resource?	Have you ever entered into, or are you currently engaged in, a contractual relationship with an IOU for an ES resource?	Does your program change how existing equipment is operated rather than provide new equipment?

Energy Efficiency (EE)	**Demand Response (DR)**	**Photovoltaics (PV/)Wind**	**Energy Storage (ES)**	**Electric Vehicles (EV)**
Does your program change how existing equipment is operated rather than replace existing equipment with more efficient equipment?	Please list any federal or state DR grant, credit or incentive you have applied for and any grant, credit or incentive you have received for your program.	Please list any federal or state PV/wind grant, credit or incentive you have applied for and any grant, credit or incentive you have received for your program.	Please list any federal or state ES grant, credit or incentive you have applied for and any grant, credit or incentive you have received for your program.	Does your program involve equipment installation, or operational and maintenance activities, above and beyond that which is considered industry standard practice? If not, please explain how your program is incremental.
Is your program a behavior-based initiative which provides information about energy use and conservation actions, rather than financial incentives, equipment, or services?	Is your program a behavior-based initiative which provides information about energy use and conservation actions, rather than financial incentives, equipment, or services?			
Does your program involve equipment installation, or operational and maintenance activities, above and beyond that which is considered industry	Does your program change how existing equipment is operated rather than replace existing equipment with more efficient equipment?			

Energy Efficiency (EE)	Demand Response (DR)	Photovoltaics (PV/)Wind	Energy Storage (ES)	Electric Vehicles (EV)
standard practice?				
Is your program a financing initiative? If so, is your program an on bill repayment initiative?	Does your program involve equipment installation, or operational and maintenance activities, above and beyond that which is considered industry standard practice?			
Have you ever submitted an EE application to an IOU? If so, was your application approved or denied?				
Have you ever entered into, or are you currently engaged in, a contractual relationship with an IOU for an EE resource?				
Please list any federal or state EE grant, credit or incentive you have applied for and any grant, credit or incentive you have received				

Energy Efficiency (EE)	**Demand Response (DR)**	**Photovoltaics (PV/)Wind**	**Energy Storage (ES)**	**Electric Vehicles (EV)**
for your program.				

Potential Framework Number 2[7]

A verbal overview of Potential Framework Number 2 was initially proposed by one CSFWG member during the second sub-team teleconference, with the following write-up provided after the sub-team meetings concluded.

Table 6 presents an additional way to consider determining incremental programs and projects in California. This generally represents that CSFWG member's understanding of the sub-team on incrementality/double-counting, but allows for a visual representation of the key considerations, namely: is there a new funding source for the program/project, how much has the proposed technology already been accepted in the market, and is there a specific local need (overloaded circuit and/or high node price points)?

Table 6: Determining Incrementalism for Programs and Projects in California

Factor	Non-Incremental Resource	Potentially Incremental Resource
Targeted Category	Funded by Existing EE Programs	Funding by Alternative Sources (*i.e.*, distribution, transmission, generation Requests for Offers (RFOs))
Existing Programs and/or Technologies	Not innately incremental	Yes, if it can be shown that existing programs/ technologies have had an insignificant impact on the market. (*i.e.*, <10% market penetration).
New Technologies	Not innately incremental	Yes, if not included in existing programs.[8]
Overloaded Circuits or High Node Prices	Not innately incremental	Yes, if localized effort significantly increases market penetration over system average. (*i.e.*,

[7] The sub-team did not have an opportunity to discuss Potential Framework Number 2 write-up as provided in this Final Report.

[8] Lifecycle savings value may be adjusted to reflect higher expected market penetration in the future.

Factor	Non-Incremental Resource	Potentially Incremental Resource
		20%-point increase in market penetration).

Potential Framework Number 3[9]

A verbal overview of Potential Framework Number 3 was initially proposed by one CSFWG member during the second sub-team teleconference, with the following write-up provided after the sub-team meetings concluded.

There clearly is some degree of "baseline" distributed resources that are going to be deployed in the face of market conditions, retail rates, and even statewide or utility service-area wide influences. The dilemma is how to determine what is "incremental" to planning assumptions when considering the potential for real solutions from DERs for a localized distribution grid need.

The concepts and questions presented here do not yet tackle the practical aspects of determining when and where a technology, project, or vendor is bringing "incremental" DERs to a specified distribution location and in a bidding framework, beyond the "planning assumptions" presumably made by a distribution planning engineer, in turn drawing upon the California Energy Commission's (CEC) forecast data for expected "additional" EE or PVs, or EVs embedded in a demand forecast.

The "screening questions" suggested in this work product for EE and DR-type DER solutions, seem non-parallel, or non-congruent with screening for less-program bound DERs such as PVs, EVs, and some kinds of storage (many are market driven, and whose initial or business as usual business models for deployment may be based on retail rate designs rather than programmatic "targets").

The dilemma may be captured through Figure 3 below. In Figure 3, the circle is intended to illustrate a single distribution planning area, *i.e.*, area of need, whereas the box illustrates the entire IOU territory. The dashed line indicates what portion of DERs is incremental and what was assumed.

[9] The sub-team did not have an opportunity to discuss Potential Framework Number 3 write-up as provided in this Final Report.

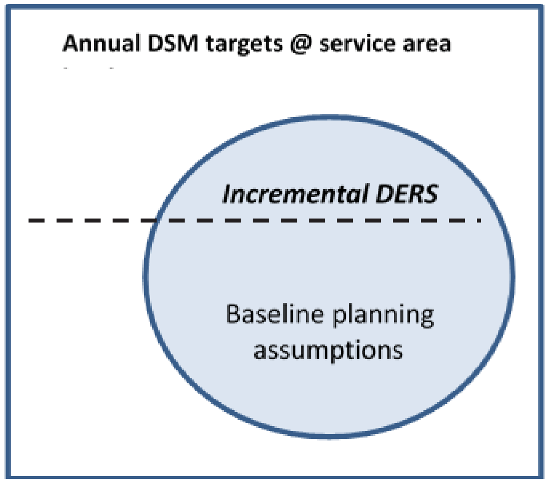

Figure 3: Illustration of System and Local Forecasts

The problem occurs because current EE service area-wide "programs" or technology deployments tend to have service area-wide annual targets, and are not geographically forecast or contractually assigned to specific distribution areas/zones. Moreover, they are currently deployed by multiple retailers, vendors, contractors, and providers without restriction or specification as to grid location.

Therefore, initially, the logical solution would be to assume a pro rata "baseline" allocation of all EE and DR programs' effects across the grid, and assign DER value only to an incremental magnitude of contractually committed DERs. This essentially would set a two-step attribution and potential pricing approach, with the first step commensurate with the pricing for incentives or performance under the statewide program, assuming pro rata impacts in the localized distribution area. Then there would be a contractual agreement to pay a competitively bid "DER value" for incremental outcomes specified in the bid and contract. Essentially, the bidder(s) would get paid the "going rate" for the baseline quantity and a "DER value" price for the increment beyond that quantity. This would be the case no matter the technology or service deployed.

Potential Framework Number 4[10]

Potential Framework Number 4 was proposed by one CSFWG member after the sub-team and full working group meetings concluded.

Based on the Working Group and sub-team discussions, the primary issues around incrementality/double-counting are two-fold:

[10] The sub-team did not have an opportunity to discuss Potential Framework Number 4 write-up as provided in this Final Report.

- How to source only the incremental DERs through a competitive solicitation when the DRP needs analysis has already assumed some potentially not well specified amount of "organic DER growth," and

- How to ensure that DERs that are bid into the solicitation have not already been procured or are expected to be procured through another sourcing channel – another solicitation, a customer program or a tariff.

The following suggestions were made for consideration and further discussion by CSFWG participants.

- The "DER growth scenario" that is assumed for the purpose of characterizing the need in the competitive solicitation should be as transparent as possible regarding whether the DERs are assumed to be sourced through another solicitation process, an existing customer program, a tariff mechanism or whether the DERs are assumed to be "naturally occurring." Naturally occurring DERs are DERs that occur without support from another solicitation, customer program or tariff.

- A streamlined "Tranche Analysis", along the lines shown in Table 7, combined with a well-specified DER growth scenario as suggested in the bullet above will significantly reduce both over-procurement and double payment for resources to meet the distribution need identified in the DRP.

- As we gain more experience with these issues and the application of these types of analysis within the competitive solicitation framework we fully expect these incrementality/double-counting analysis will evolve.

Table 7: DER Tranche Analysis

Tranche	Category	Description	Incremental	Procure
1	Not Already Sourced Through Another Channel	New technology or service that is not already being sourced or reasonably expected to be sourced through another solicitation, program or tariff that meets the identified distribution need. Example: Hybrid or all electric water heater	Yes	Yes, if least-cost/best-fit resource

Tranche	Category	Description	Incremental	Procure
		program to provide low cost residential ES/DR.		
2	Partially Sourced Through Another Channel	Existing technology or service that meets the identified distribution needs but at least some component of that technology or service is already begin sourced through another solicitation, program or tariff. Example: Installation smart inverters to existing rooftop solar system that do not have that technology. The existing PV system is being "sourced" through the Net Energy Metering (NEM) tariff. Only the smart inverter and the services it provides would be incremental. Example: Transforming an existing co-pay direct install EE program to a free direct install program to	Yes, but only the portion (if any) that is not currently being sourced or can reasonably be expected to be sourced through another solicitation, program or tariff with the same locational and temporal granularity and performance guarantees as the bid technology.	Yes, if least-cost/best-fit resource but only the incremental portion that meets the identified distribution need that is not already being sourced through another solicitation, program or tariff. Option to procure both the incremental and non-incremental portion if the non-incremental portion can be procured at a lower cost than is being paid or is expected to be paid through existing or reasonably expected future solicitations, programs or tariffs.

Tranche	Category	Description	Incremental	Procure
		increase uptake in a targeted area. Only the extra costs and extra uptake would be incremental.		
3	Wholly Sourced Through Another Channel	Everything not covered by Tranche 1 or 2, above. Example: Vendor bids in a residential AC direct load control bid that is equivalent to our existing residential direct load control offering but more expensive.	No, technology is already being sourced or is reasonably expected to be sourced through another solicitation, program or tariff with the same locational and temporal granularity and performance guarantees as the bid technology.	Option to procure if the distribution service can be procured at a lower cost than is being paid or is expected to be paid through existing or reasonably expected future solicitations, programs or tariffs.

Potential Framework Number 5[11]

Potential Framework Number 5 was proposed by one CSFWG member after the sub-team and full CSFWG meetings concluded.

This framework includes the following criteria for incrementality, which can be reevaluated at a later date once we have additional experience to draw from. Keeping these criteria simple, actionable, and encouraging of market innovation will be vital to learning from this process and developing competitive solicitations as a useful tool over time.

If the DERs offered provide the attributes defined in the solicitation request with the appropriate performance requirements, then they will count as additional in these cases:

A. When the <u>attributes</u> of DER resources have not been "sourced" through other mechanisms (*e.g.*, tariffs, programs, other competitive solicitations) they will be considered incremental. For example, if an EE project is not funded through programs (and not counted toward utility goals) it will be eligible to bid. In addition, existing resources can bid in attributes that were not paid for through other sourcing mechanisms.

[11] The sub-team did not have an opportunity to discuss Potential Framework Number 5 write-up as provided in this Final Report.

For example, rooftop PV may be supported by the NEM tariff or other incentives, but if their smart inverter capabilities were not "sourced" as part of that tariff they can be bid in to a competitive solicitation and receive an additional payment for the additional attribute offered. Or if additional PV is built above and beyond what was forecast by the distribution planner.

B. When the attributes of DER resources have been sourced at least partially using other mechanisms (*e.g.*, tariffs, programs, other competitive solicitations) at least a portion of those resources (to be determined) may be considered incremental if the bidder is able to demonstrate increased market participation due to the combined incentives. There are a number of ways this could work, for example the Brooklyn-Queens Demand Management example of combined incentives discussed at the July 14 CSFWG meeting, or a bidder is able to provide uptake that exceeds the expected market penetration that has been forecasted. The "burden of proof" for incrementality would be higher here than for A, and may require a set of examples where combining sourcing mechanism may be acceptable, as well as a case-by-case review in some situations at least in the beginning.

Additional Discussion

During the final CSFWG meeting, as well as in written form after the meeting, various parties provided additional comments on this topic. These are provided below:

- Incrementality may need to consider the time of day that a DER provides its attributes.

- Potential for arbitrage: If a particular DER can get a higher revenue stream through an RFO than through a DER-specific program incentive or tariff, a vendor may choose to offer its DER's attributes through an RFO. This could result in the IOU paying more for a DER attribute via a winning RFO bid than it would have paid via the incentive/tariff program, which ultimately translates to higher customer rates. Conversely, a DER could be operated differently than the status quo to meet the needs of an RFO instead of or in addition to operating it through a specific program or tariff, which would be incremental.

    a. Counterpoint: While it may be true, in some cases, that the revenue stream awarded for a particular DER through the RFO mechanism may be higher than what a utility payment would have been through an existing incentive/tariff program there may be specific contract delivery and contract requirements in the RFO mechanism that require different pricing. It should be noted that this is not an "apples to apples" comparison.

- A DER developer that is participating in an existing IOU-sponsored incentive program may be able to adjust the operational characteristics or program design (location, target customers, etc.) associated with their DER marketing strategy so that at least a portion of the DER's attributes are incremental to the planning assumptions. This is illustrated in Figure 4.

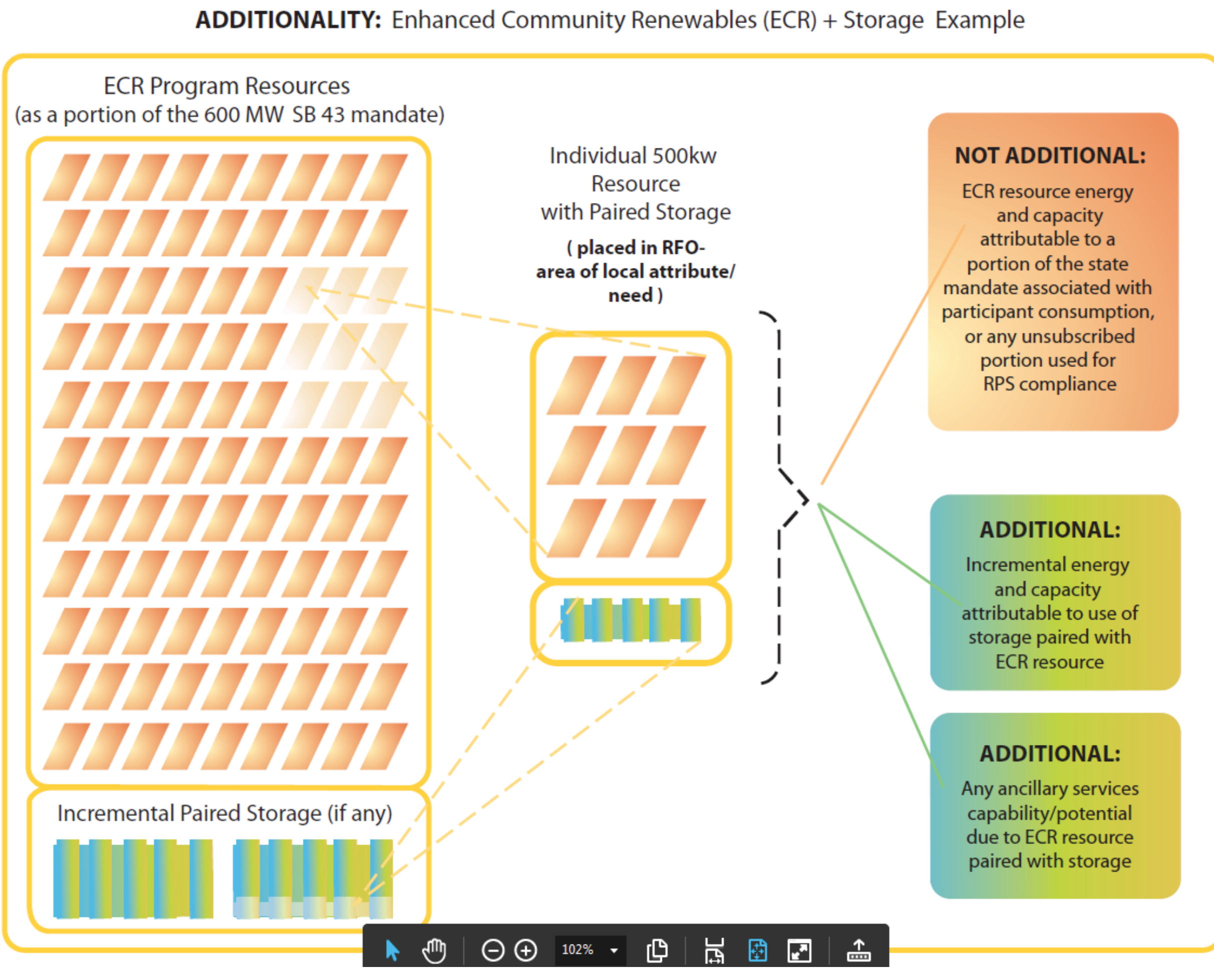

Figure 4: Illustration of Resources Providing Additional Services

- There is a debate regarding whether EE/DR offered in a competitive solicitation bid are offering a different set of attributes, *e.g.*, controls, communications, feedback, etc., than are offered in the regular EE/DR programs. They may be paid to provide certain performances but they do not need to commit to performances.

- One CSFWG member offered the following comment: We appreciate the value of the forecast and the good work of the agencies and contractors in its development. It is used as a guide for the program development in the Rolling Portfolio and will continue to be for the foreseeable future. However, the value of utilizing it as the basis for other procurement decisions is not apparent and may actually undermine EE as a procurement resource. If a utility were to work their way down the list of questions for EE that might guide the determination of whether DER attributes included in an offer are incremental (as described in Potential Framework Number 1) by the time they get to the bottom of that long list, we cannot see how there will be any eligible EE measures left for the utility to consider regardless of the stranded opportunities that we know are available in the marketplace.

Relying on whether something has previously been counted in the CEC forecast to determine whether EE can be procured at the distribution level to be delivered to meet a different grid need, ignores the reality that the savings are there to be captured and delivered.

The utilities are not funding existing programs enough in the Rolling Portfolio to access all technical potential. And the rules that the Rolling Portfolio is subject to are not consistent with what is needed for EE procurement as a grid and distribution resource.

The only limitation on EE bid into an RFO should be whether the proposal directly competes with another program already targeted by a program administrator in the region encompassing the RFO (*e.g.*, the EE bid for retro-commissioning of restaurants and restaurants are already included in a portfolio of a program administrator).

The work of the sub-team does not fully reflect the challenges of applying the concepts of incrementalism and double-counting in an RFO setting. The complexity of applying the concept is daunting. We have planning and implementation on the EE program side (the Rolling Portfolio) which is on a completely different timeline than that which the IOUs are proceeding on for distribution needs and yet on a still different schedule from the planning and development of the forecast.

Application of the incrementality concept and double-counting as presented in the sub-team will interfere with the goal of having the market deploy the least cost, lowest carbon, most technically appropriate resources. Finally, this approach disadvantages EE against other DERs and generation resources.

- One CSFWG member offered the following comment: We do not support the guiding principles. Basing what counts as incremental and what does not on "reasonable planning assumptions" that currently are not clearly defined and are likely to change due to recent policies such as Senate Bill 350 is a recipe for uncertainty and complication in the early days of experimenting with competitive solicitations for distribution investment deferral – when instead we should be focused on spurring market innovation and evolving this tool as we learn over the next several years. After some experience with these solicitations and further development of these planning assumptions, we would support reconsidering these guiding principles, but at this time we believe it will be counterproductive and unworkable to use this framing as a basis for identifying incrementality. We note in particular that EE is disadvantaged by this framing – the "peanut butter spread" method for applying EE at the distribution level is imprecise and will leave significant additional resources on the table. It is also important to recognized that the EE that would provide the attributes requested with the appropriate performance requirements for investment deferral is not the same as the EE currently procured through programs – which is largely procured without regard to location, timing, or the performance requirements necessary to depend on it as an *investment deferral* resource.

C. Rules and Oversight

Summary of Progress

The CSFWG combined the topics of solicitations rules/principles and oversight into one discussion topic. In initial discussions, the CSFWG was able to reach consensus on 12 principles that should apply. In subsequent discussions, the CSFWG, and the sub-team associated with this topic, were not able to reach consensus on the details of the rules and oversight. The sub-team was able to develop a few concise recommendations, which are included below.

Consensus Items from Status Report

The CSFWG identified twelve principles in the existing procurement process that may apply within the DER competitive solicitation framework: (1) Meet the identified need on a least cost, best fit basis; (2) utilize a competitive process with broad markets; (3) technology neutral, *i.e.*, solicitation does not preclude any technology – must meet the need; (4) transparency as allowed within the boundaries of confidentiality;[12] (5) identify a need without prejudging the technology of the solution; (6) do not limit the amount of anyone type of DER technology type, *i.e.*, be allowed to maximize the use of the most cost effective solution; (7) a streamlined process; (8) a fair and consistent process; (9) focus on the identified needs; (10) sufficient assurances of performance; (11) allow flexibility in the number and types of bids (at least initially) to allow the market to be creative in solutions; and (12) lessons learned feedback loop.

Recommendation from Sub-Team 4[13]

The sub-team focused their discussions on four topics:

1. Distribution Planning Advisory Group (DPAG)
2. Expanded Procurement Review Group (PRG) activities to incorporate DER deferral projects
3. Independent Professional Engineer (IPE)
4. Distribution deferral project need authorization and bid approval process

The sub-team was unable to reach consensus in their discussions. When presented to the CSFWG, these was also no consensus on these recommendations. The recommendations are provided, with the level of consensus at the sub-team level identified. Additionally, ORA's comments submitted on July 18, 2016 are included as Appendix 6, along with a flow chart outlining the solicitation framework process.

1. Distribution Planning Advisory Group (DPAG): (Some Consensus)

The sub-team recommends creating a DPAG, which provides advice to the IOUs on the following:

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[12] Two types of transparency were identified: (1) transparency to ensure that rules and principles are being followed, and (2) transparency in that the process is well understood.

[13] Additional, more detailed materials developed by this sub-team are included in Appendix 6.

(1) *Process for IOU consideration of proposed electric distribution capacity deferral projects consistent with the IOUs' safety, reliability and affordability obligations*, including use of approved ICA and LNBA with respect to how they inform the IOUs' electric DPP.

(2) *Routine electric distribution planning activities that relate to DERs* such as:

a. Ensuring identification of Distribution Capacity and Voltage Management Requirements that can be deferred by deployment of DERs – DER Deferral Project Process Review

b. Ensuring identification of Operations and Maintenance Activities that can be deferred by deployment of DERs – DER Deferral Project Process Review

c. Ensuring identification of Circuit Reliability Activities that can be deferred by deployment of DERs – DER Deferral Project Process Review

The routine electric distribution activities that relate to DERs should be aligned with the basic Distribution Services that have been developed and vetted by stakeholders, which are further described within the Distribution Services, Attributes and Performance Requirements section of this report.

The sub-team failed to reach consensus on:

- A schedule for the timing (as-needed, monthly, quarterly, semiannually, annual) and mode (in-person or teleconference) of DPAG meetings, and
- Whether additional electric distribution planning activities that relate to DERs should be subject to the DPAG, such as advice on the results of DER sourcing activities and the approval of DER project costs and commercial terms and conditions.
- [It is likely that further discussions may provide additional guidance on these aspects as part of the scope of the Commission's DRP proceeding.]
- The ability of market participants (MPs) to participate in some way within the DPAG. The IOUs raised market manipulation and confidentiality concerns related to MP participation. Other parties expressed interest in MP participation in the DPAG related to some or all of the DPAG activities discussed above.

2. Expanded PRG activities to incorporate DER deferral projects: (Divided)

Some sub-team members recommend that bid review for compliance with technical specifications for distribution capacity deferral projects should be delegated to the existing energy resource PRG group, which could employ an Independent Professional Engineer (discussed in detail below) to give PRG members sufficient confidence to determine a bid's technical capability to meet a distribution grid deferral project's needs.

One member believes a new distribution-specific PRG is needed to bring an appropriate level of distribution expertise to the oversight process.

Other sub-team members recommend reviewing bids in the DPAG group where non-IOU parties are more likely to send representatives with sufficient technical expertise to evaluate the bid's ability to meet distribution deferral project technical requirements.

One member believes the DPAG should include market participants, and thus it would be inappropriate for such a group to review bids.

Other sub-team members state that the review of specific electric distribution services contracts that defer distribution capacity is not within the scope of the CSFWG or the existing PRG, but instead is subject to the Commission's DRP proceeding and the testing and demonstration through the proposed demonstration projects pending in that proceeding.

3. Independent Professional Engineer (IPE): (Mostly Consensus)

The sub-team recommends adoption of an IPE to independently evaluate DPPs, providing input to the DPAG.

An IPE would generally be required to possess the following credentials: (1) degree in engineering and specializing in power, (2) California Licensed Professional Engineer (PE), (3) familiarity with the distribution grid, and (4) familiarity with technical specifications of various types of DERs.

An IPE pool consisting of at least two IPEs per IOU would be chosen by a competitive process. IPEs would not overlap within IOU IPE pools. The IPE can be a consultant or employed solely for this purpose.

One party believes a pool of IPEs, not limited to two, is more appropriate to capture the deep experience that may be required with regard to specific forms of DERs that might be deployed.

Sub-team members agree that IPEs must be free from conflicts of interest.

To avoid a conflict of interest, or the appearance of a conflict of interest, some parties also recommend the Commission's Energy Division (ED) contract with the IPE directly or that ED manage the contract directly as a reimbursable contract authorized by Commission order in the IDER, with appropriate cost recovery.

Other parties recommend the IOUs manage the IPE contract with costs reimbursed through appropriate ratemaking as is currently the process for Independent Evaluators (IEs) in the procurement process.

Sub-team members support the following work product for IPEs:

(1) Reports on DER Deferral Process

Example IPE Report Template

1. Describe in detail the role of the IPE throughout the review of the IOUs' process for need determination and evaluation of non-wires DER projects that seek to defer distribution capacity investments.

2. Is the IOU's methodology for the DER deferral project evaluation and selection designed fairly?

3. Describe the DER deferral process with particularity. The IPE report should indicate, to the extent applicable, how and where the DER deferral process relates to the IOU's electric distribution capacity planning process.

(2) Presentation to DPAG on IOU processes for distribution deferral need authorization

(3) Presentation to PRG on processes for IOU evaluation of non-wires DER deferral projects

Some parties recommend the IPE help track distribution infrastructure deferred through DER in a report submitted contiguously with the IOU's General Rate Case (GRC). Other parties do not support IPE preparation of this GRC-related report.

Additionally, some parties recommend creating a standard pro forma contract and a standard conflict of interest form for IPEs. Other parties suggest this is unnecessary.

4. Distribution deferral project need authorization and contract approval process: (Additional Work Recommended)

The Commission authorization and approval process elicited a robust discussion from select stakeholders but input was limited. This suggests that further development of informational material and time for party consideration are warranted for this important topic.

- During the sub-team discussion, several parties expressed a desire to expedite distribution deferral project review.
- Some participating sub-team members discussed a preference for categorizing distribution deferral projects as either near-term or long-term, depending on the DER deferral project's required operational date.
- One party expressed concern with multiple procurement mechanisms potentially disadvantaging certain DER types or portfolios.
- Another party expressed concerns that possible expedient reliance on individual DERs' procurement, rather than optimized portfolios, could fail to serve the intent of Public Utilities Code Section 769 to maximize net benefits for consumers.
- Another party recommended that the specific activities and scope of the DPAG be subject to further review and discussion in connection with the IOUs' DRPs in the DRP proceeding, in order to avoid creating delays and duplicative review and approval processes for the IOUs' non-wires distribution capacity projects.

Deferral projects with long-term planning horizons:

- Some sub-team members suggested a process for approval of long-term deferral project need authorization using a Tier 3 advice letter submitted as identified through the annual Distribution Procurement Plan (described below in the near-term planning horizon section). An application or advice letter could serve as a vehicle for contract authorization.
- Other sub-team members stated that the process for Commission approval of DER distribution capacity deferral projects is not within the scope of the CSFWG, but instead is within the scope of the DRP proceeding and other Commission proceedings for approval of electric distribution contracts and services, such as GRCs.
- The sub-team reached no consensus on the mechanism for contract approval subsequent to solicitation. Discussions did highlight that, depending on time horizon, different mechanisms may be needed and used.

Deferral projects with near-term planning horizons:

Some participating sub-team members generally supported the concept of exempting projects with a near-term project horizon from DPAG advisory review, though there is no specific agreement on how to draw the line between short-term and longer-term deferral projects. Other sub-team members stated that DER deferral project exemption proposals are premature and outside the scope of the CSFWG. Similar in concept to Bundled Procurement Plans currently used, the DER deferral short-term procurement plan would discuss DER deferral more generally and create upfront standards for DER procurement for distribution deferral. IOUs would submit the DER deferral procurement plan as an application, or in an on-going proceeding, for Commission review. Subsequent need authorization and contract bid approval would proceed with less Commission scrutiny such as through Tier 1 advice letters because the DER deferral procurement plan with upfront standards would already be approved by the Commission.

Parties expressed concerns regarding the ability of the current CSFWG to implement a DER deferral procurement plan mechanism at this time, as the mechanism depends on the creation of up-front standards which are not yet developed or vetted. Additionally, parties expressed concern that the current scope of the CSFWG may limit development of the DER deferral procurement plan as it precludes discussion of the relative merits of using Tier 1 advice letters through upfront-standards or through tariffs. Moreover, the relative merit of contracting through solicitations versus bilateral contracting is out of scope for this Working Group. Further development of the DER deferral procurement plan for projects with near-term planning horizons may benefit from further discussion in subsequent forums with a wider scope, such as the DRP proceeding.

Additional Discussion

It was noted during the CSFWG meeting that this sub-team focused on one portion of the spectrum of oversight and that a broader look at all the steps involved in a competitive solicitation should be included in the final report. Figure 5 was offered by one party as a

potential process. This proposal was not discussed by the CSFWG, nor the sub-team, but is included as an illustrative example of the overall process.

<table>
<tr><td>1. Deferral Project Identification</td><td>• Distribution Planning Advisory Group (DPAG) - Identifies distribution projects which can be deferred or eliminated by distributed energy resource (DER) procurement through an investor Owned Utility (IOU) solicitation mechanism.
• Independent Professional Engineer (IPE) - Evaluates the distribution grid project and approves of the DER attributes the IOU proposes will defer the project as reasonable.</td></tr>
<tr><td>2. Commission Need Authorization</td><td>• Tier 3 Advice Letter (AL)
    • A confidential attachment to the AL stating the DER deferral value of the “wires solution.”
    • Reference the applicable funding in the IOU’s General Rate Case (GRC) filing.
    • IPE certification that DER attributes and deferral value are reasonable.
• DER Procurement Plan – Developed in future phases of integrated Distributed Energy Resource (IDER) and incorporated in the DRP.</td></tr>
<tr><td>3. Solicitation</td><td>• Procurement Review Group (PRG)/ Independent Evaluator (IE)
    • RFO Launch: Bidders Conference, bid submission, bid review and screening, contract negotiation, portfolio review).
• Portfolio selected using adapted Least-Cost Best-Fit Valuation: “Total wires solution value” measured against “Total DER value for DER deferral” plus “Total other DER value”.
• Portfolio Review and Approval
    • IE oversight and consent of adapted Least-Cost Best-Fit evaluation results.
    • IPE oversight and consent of DER portfolio attributes’ collective ability to meet distribution deferral need and sufficiency of physical assurance.</td></tr>
<tr><td>4. Commission Approval</td><td>• Tier 3 Advice Letter pending the following requirements
    • "Wires solution" value > DER distribution deferral value OR "Wires solution" Value > Total value of Bid Portfolio
    • Cost Effectiveness verified by IE
    • DER portfolio attributes verified to meet "wires solution" by IPE
    • If any bids include gas-fired generation resources, there must be an affirmative showing that greenhouse gas emissions are reduced over the total life of the resource.
    • Approval of the solicitation bids does not raise policy questions.
• Application.</td></tr>
<tr><td>5. Cost Recovery</td><td>Energy Resources Recovery Account (ERRA) and Distribution Revenue Adjustment Mechanism (DRAM) - IOUs recover the cost of Bids plus the IOU incentive value less the DER Deferral Value through ERRA and DRAM.</td></tr>
</table>

Figure 5: Potential Solicitation Regulatory Process

Additionally, one participant suggested additional DPAG activities in comments. These ideas are not yet vetted by the sub-team but are offered here for further consideration.

(1) Use DPAG to evaluate current and projected DER performance capabilities, costs and innovative DER portfolios and solutions.

(2) Review potential additional grid services for prospective DER solutions. Potentially the services identified as additional services in the Services section of this report.

The topic of time required for each procurement process and oversight process was identified in discussions for this group, but was not fully developed.

D. Valuation

Summary of Progress

The CSFWG identified potential valuation components that could be used for future solicitations. The group was able to reach consensus that this is a viable starting point, but did not reach consensus on how the valuation process would be implemented, including selecting which valuation components would apply and the level of transparency in making that decision.

Recommendation from Sub-Team 2.b

The sub-team for this topic developed both a descriptive narrative and a tabular version of the valuation components that could be used. The narrative is included in the body of this report, whereas the table is included in Appendix 4.

Evaluation Process Overview

The electric utilities employ Least Cost, Best Fit (LCBF) principles in evaluation process of their existing solicitations such as Renewables Portfolio Standard (RPS), Combined Heat and Power (CHP), and SCE's Local Capacity Requirements (LCR) RFOs, and All Source RFOs for RA and energy. In accordance with D.04-12-048, LCBF methodologies takes into account the qualitative and quantitative attributes associated with bids to obtain the best value and most cost effective solutions for the electric customers.

The results from an evaluation will inform selection of Offers with which IOU will enter into negotiations. An evaluation methodology is developed and implemented under the oversight of the Independent Evaluator (IE), the Procurement Review Group (PRG), and Energy Division (ED) staff.

In general, the electric utilities' evaluation process consists of three steps:

- Initial screen
- Quantitative valuation
- Qualitative evaluation including selection constraints

Initial Screen

Once bids are received for a solicitation, an initial review is performed for the completeness and conformity of the offers with the solicitation protocol. The review parameters include conforming delivery point, conforming commercial on-line date, conforming term, conforming operating requirements, minimum/maximum project size, any interconnection requirements. If sellers lack any of the requirements, electric utilities allow a reasonable cure period and work directly with the sellers to remedy those deficiencies. Once the cure period is over, the data of all the conforming bids is gathered and made ready for further steps of evaluation.

Quantitative Valuation

For quantitative valuation, Net Present Value (NPV) calculations are performed for each bid. The NPV analysis entails (1) projecting various benefits and costs streams over the life of the bid proposal, (2) applying time value of the money, and (3) estimating total net present value as present value of benefits minus present value of costs.

The electric utilities develop their market price forecasts using proprietary models for ascribing value to various attributes like RA capacity, electrical energy, ancillary services, RPS credits, and GHG allowances. The quantity of these attributes are projected based on bid specifications, guidance from CPUC/CAISO rules, dispatch models or generation profiles. For load reducers, the quantity of these attributes is estimated on the reduced requirement basis.

Qualitative evaluation including selection constraints

The attributes that cannot be reasonably quantified are characterized as qualitative. These qualitative attributes include portfolio diversity, seller concentration, overall utility's portfolio position and need, site diversity, interconnection status. The qualitative considerations are reviewed along with quantitative results during selection process. The selection method can vary from simple rank ordering based on evaluation metrics to complex optimization. The optimization model is warranted when there is specific set of constraints to meet portfolio requirement, and/or there are mutual inclusivity or exclusivity conditions offered by the bidders. Setting qualitative factors as selection constraints is another of way of implicitly attributing quantitative value to these factors. The optimization is generally done on the iterative basis to review various cost-effective solutions along with the other qualitative factors that could not be considered as selection constraints.

Principles for Developing Solicitation Methodology for Competitive Solicitation Framework

In developing the solicitation evaluation methodology for DER procurement, CSFWG had consensus on using LCBF framework. For valuation of deferred distribution upgrade, the group proposed to base it on the approach being developed as part of DRP's LNBA methodology for location-specific deferral value. In addition, the CSFWG agreed upon the following set of principles:

1. *Consider the potential services beyond what is asked in the solicitation and other conceivable benefits/costs provided by DERs as qualitative factors*

The additional value provided by DERs at secondary level include enhanced grid services provided by advanced smart inverter, potential market price suppression due to reduced need, potential equipment life extension/reduction, and CVR. Such type of attributes cannot be reasonably quantified today, but can be used as bids differentiator through qualitative factors when applicable.

2. *Continue to refine the evaluation methodology as new market rules and potential values/costs develop, and integrate "lessons learned"*

DERs to defer distribution need is a new market we are embarking into, it will, in turn, potentially give way to new products, services and rules. The CSFWG identified the need to continually refine the evaluation methodology to reflect the new market developments to ensure accurate and fair valuation. The "lessons learned" should also be integrated in the evaluation process as our understanding of both positive and adverse impact of DER adoption on the electric system advances.

3. *Avoid double-counting of benefits and costs*

As we continue to augment the traditional list of values provided by a resource of RA, energy and A/S, there is a need to ensure that benefits and costs are being accounted for accurately and any double-counting issues should be thoroughly discussed and avoided.

Evaluation Methodology

The CSFWG discussed the below set of quantitative and qualitative factors.

1. *Quantitative Factors*

Quantitative factors include Net Market Value (NMV). NMV intends to represent the value of an Offer from the market perspective. The NMV captures the market value provided by an Offer of Energy, A/S, and Capacity and compares it to the Offer's cost. NMV is calculated for each Offer as follows:

NMV (levelized $/kW-year) = Benefits - Costs

Where Benefits =

RA (Capacity) Value

Energy Value

Ancillary Services Value

RPS Benefit

Reduced GHG Emissions Benefit

Renewable Integration Cost/Reduced Cost Benefit

Distribution Deferral Value

Transmission Deferral Value

And Costs =

Contract Payments Costs (including Fixed and Variable Costs)

RA Value Benefit

The RA (including system, local and flexible) amount attributed to each resource is established under the guidance of the current net qualifying capacity counting rules of the CPUC. As new rules are implemented, the methodologies to determine RA capacity for the associated resources are replaced to reflect new guidance. If a resource's operational capabilities generally fall under a category described by the CPUC for RA counting rules, the rules are applied directly. When no such category is identified, electric utilities may use program/technology specific studies/proceedings to estimate the impact of resource on peak load or assess the contribution to peak load through their own analysis.

The resources that act as load reducers may receive adjustments to their RA quantity benefits to reflect avoided T&D losses and RA reserve margin requirements.

The RA price forecast is developed from multiple sources and assumptions such as market transacted data from utilities' own previous solicitations, local requirements, long-term capacity value, cost of generation studies, and planning reserve margin assessment. There is inherent uncertainty in the RA price forecasts, therefore there is no guarantee that the ascribed RA value to a resource during the time of solicitation will be realized in the future.

Energy Value Benefit

The energy amount attributed to must-take and baseload resources is based on the bid's expected generation delivery profile. For dispatchable resources, operations of the resource are projected using the economic dispatch principle based on bid's operating characteristics, operating costs and market services offered.

The resources that act as load reducers may receive adjustments to their energy quantity benefits to reflect avoided losses.

The energy price forecast is generally established using forward market data and fundamental model prices. The location-specific adjustment are done to reflect associated congestion value forecasts. As discussed for RA price forecast, there is inherent uncertainty in the energy price forecasts, therefore there is no guarantee that the ascribed energy value to a resource during the time of solicitation will be realized in the future.

Ancillary Services (A/S) Value Benefit

The A/S amount is projected based on first determining if a resource is capable of providing A/S. If the resource can provide A/S, then similar methodologies as energy amount forecast are used to determine A/S amount to be attributed to the resource.

The A/S price forecast could be based on historical market data, statistical model or fundamental model. As discussed above for RA and energy price forecast, there is inherent uncertainty in the A/S price forecasts, therefore there is no guarantee that the ascribed A/S value to a resource during the time of solicitation will be realized in the future.

RPS Benefit

The eligible renewable DERs that count towards utilities' RPS compliance requirement get RPS benefit. Their RPS benefit quantity is calculated from their generation delivery profile. The load reducing DERs also get RPS benefit as they result in reduction in utility's RPS compliance requirement. The reduced RPS compliance requirement is calculated based on total reduced bundled load projection from the resource and RPS standard targets.

The electric utilities forecast Renewable Energy Credit (REC) value from their own RPS solicitations data, third party vendors' subscribed data and public market reports.

Reduced GHG Emissions Benefit

The load reducing DERs or renewable DGs get the benefit of not have any combustion-related GHG compliance obligation and corresponding costs. There is not separate quantification of this benefit as DERs receive the value of avoiding GHG emissions via the value of reduced generation need energy costs. The emission costs are embedded into LMP prices.

Renewable Integration Cost/Reduced Cost Benefit

The renewable resources integration requires flexible resources that the utility and/or the CAISO can control to manage and firm-up intermittent output. For the DG resources where renewable integration cost is applicable, Renewable Integration Cost Adder (RICA) methodology from RPS proceeding is generally employed.

Certain DERs can reduce the cost of integrating intermittent renewable generation by providing the operational flexibility that the system needs. By providing such flexibility, the system operation costs are reduced which otherwise have been incurred in acquiring flexible resources. However, to the extent this benefit is captured in flexible RA or ancillary services value, it is appropriate to not double-count this benefit.

Distribution Deferral Value

As identified in DRP's LNBA methodology, deferred distribution components would include

a. Sub-transmission, Substation and Feeder Capital and Operating Expenditures

b. Distribution Voltage and Power Quality Capital and Operating Expenditures

c. Distribution Reliability and Resiliency Capital and Operating Expenditures

The CSFWG has proposed to develop deferral values using Real Economic Carrying Charge (RECC) method based on the approach being developed in the DRP.

The benefit of distribution deferral will be evaluated for DERs that are located on identified substations and/or feeders. Such benefit will be assessed based on the deferred cost of the least expensive traditional solution meeting the identified operational need on that distribution location, *i.e.*, the project that would most likely be built in the DERs' absence. The main factors in the analysis for each alternative include the installed cost, the operating and maintenance cost, project life, return on investment, and discount rate.

Transmission Deferral Value

There are various public processes that determine the required transmission projects in the CAISO controlled grid, and the utilities also conduct their own transmission reliability assessment in parallel to CAISO's Transmission Planning Process. Using the cost of traditional grid investment and by identifying specific system characteristics (or needs) driving the need for the transmission projects, a deferral value or avoided cost may be calculated. The factors like interrelationship between transmission system planning and distribution system planning, coincident peak between DER and transmission need will be taken into account to determine any potential contribution of DERs in deferring transmission capital and operating expenditure.

Contract Payments Costs

The contract costs could be composed of capacity payments and/or energy payments, *i.e.*, fixed costs and variable costs. The energy payments could be associated with generation as all-in cost for DG type of resources, or variable costs for DR/ES type of resources.

2. Qualitative Factors

Qualitative factors include: "Project Viability," "Voltage and Other Power Quality Services," "Equipment Life Extension," "Societal Net Benefits" and "Other Factors."

Project Viability

The project viability assessment includes factors such as developer experience, O&M experience (proven track record), commercial technology, reasonableness of delivery date, and interconnection progress.

Voltage and Other Power Quality Services

The voltage and other power quality services stream that are not identified as DER portfolio need during solicitation, but deemed to be providing value to the system are also considered while selecting bids.

Equipment Life Extension

If certain DER bids are deemed to have impact on extending/reducing the distribution equipment life, the attribute would be considered as part of qualitative consideration while selection, as secondary benefit or cost.

Societal Net Benefits

Where identified, societal benefits and/or costs include public benefits and/or costs that do not have any nexus to utility rates. The societal net benefits attribute is planned to be leveraged from various other proceedings such as the DRP's LNBA methodology, and the IDER's demand side cost effectiveness. Rather than perform duplicative efforts within this Working Group, it is best for discussions regarding societal net benefits to take place as part of the IDER proceeding's efforts to address the Energy Division Staff's identified Phase 3 efforts to remedy the shortcomings in the current cost-effectiveness framework, as was proposed in the Cost Effectiveness Working Group's Final Report. It is appropriate to include any societal net benefit that can clearly be linked to the deployment of the proposed product.

Other Factors

Other factors include considerations like supplier diversity, counterparty concentration, site diversity, technology/end-use diversity to help market transformation

3. Other Discussion Points

DER counting rules

Similar to RA counting rules, the counting rules for projected reactive power deliveries and other services will need to be developed for different DERs.

Headroom for DER portfolio size

There will be a headroom needed for solicited DER portfolio size relative to the identified distribution capacity need due to:

The risk of contracts fall-out

The cost effectiveness of DERs relative to the distribution asset will be done at a portfolio level. If the contracts within the portfolio fall-out, then that poses the risk of new portfolio being cost effective at the later time. Some headroom will need to be built during initial portfolio design based on contracts success rate expectations.

Additional Discussion

During the final CSFWG meeting, as well as in written form after the meeting, various parties provided additional comments on this topic. The additional comments did not change the consensus on the recommendation, but are included for completeness.

- There was no consensus on the transparency of the process. MPs would like to understand the details of the evaluation criteria (even including the value of the deferred investment), and IOUs feel strongly that this must be kept confidential.
  - The timing and form of this transparency was discussed in some detail, but no consensus was reached.
- Additional valuation cost components were suggested:
  - Testing costs
  - Avoided operations & maintenance
  - Cost associated with utility purchasing DER
- A desire to better understand the process to compare the bids to the value of the traditional solution was expressed.
- A desire to better develop and articulate the relationship between ICA and LNBA and the valuation process was expressed.
- Parties suggested a principle to not have valuation, or any part of the procurement process, create a barrier to realizing additional value streams.
- A two-step valuation process was proposed, which is detailed in Appendix 4.

E. Pro Forma

Summary of Progress

The CSFWG was able to reach consensus on the types of changes that would be required to modify existing contracts, or term sheets, for distribution deferral purposes. As part of this topic, the CSFWG also discussed the topic of a technology neutral pro forma, but was not able to reach consensus on the need for the contract or the process to develop it.

Recommendation from Sub-Team 5

Through the discussions of this sub-team, two areas of recommendations were identified: modifications to reflect solicitations aimed at distribution deferral projects and improvements to existing pro formas.

A set of pro forma contracts was offered up as a reference point for this Working Group's discussions to focus on (accessible through https://sceprprfo.accionpower.com/_scedgpr_1501/documents.asp?Col=DateDown&strFolder=a.%20RFO%20Documents/iii.%20Pro%20Forma%20Purchase%20and%20Sale%20Agreements%20[PSAs]/&filedown=&HideFiles=). These contracts were used as examples for the sub-team to better understand past practices. Terms and conditions specific to the solicitation for a distribution deferral need will need to be developed. The changes/recommendations identified by this sub-team are not necessarily specific to these pro forma contracts, but rather are meant to provide guidance to the development of any future contract, regardless of starting point. These sample pro forma contracts include one hybrid technology (storage plus generation in front of the meter) contract, which is currently undergoing substantial changes.

Distribution Deferral Changes

The potential changes are captured in Table 8. The areas of the sample pro forma contracts that would be modified to address each of these areas is included in Appendix 4. There was consensus from the group that these are the types of changes that would need to be made for a competitive solicitation targeting a distribution deferral need. Parties were split on the level of detail in this table being adequate to fully understand the future modifications.

Table 8: Potential Pro Forma Distribution Deferral Changes

Area	Description/Thinking	Pre-Operational	Operational
Performance based payment structure during the distribution deferral period for solar resources.	This could take the form of a fixed payment related to performance during this period or an adjustment to energy payments which creates the same effect.	N	Y
There would be an increase in the number of pre-operational milestones, as well as consequences for not meeting these milestones.	a) IOU's approach could likely be that if the milestone was missed, but could be achieved in a short time and the service provider showed how this would not impact the on-line date, then the development security could increase, but there would likely not be a termination right. b) If the milestone could not be achieved soon and this would impact the on-line date, then a termination right would occur.	Y	N
Development security in the agreement	Need to be increased due to the critical reliance on the DER product to provide the ability to defer the need to build the distribution system upgrade. The level of development security may vary based on the need being filled.	Y	N
Performance assurance in the agreement	Need to be increased due to the critical reliance on the DER product to provide the ability to defer the need to build the distribution system upgrade.	N	Y
The agreement would have to be modified to accommodate the voltage support product	a) Some DERs (PV and ES) can provide voltage support up to a certain volume without impacting kWh output. Above that level, output must be reduced. b) Other DERs have to reduce output as soon as they supply voltage support.	N	Y

Improvements to Existing Pro Formas

The following challenges were identified by an industry member of the sub-team and were presented to this sub-team and the full CSFWG group for discussion. No consensus was reached on these issues, and some were identified as not related to pro forma contracts. These are included in this section, since they were developed in this sub-team.

Industry Challenges in past DER competitive solicitations

1. Lack of sufficient information available to bidders in advance.
   - Led to failure to procure the minimum capacity for preferred resources.
   - Procurement plan, resource performance requirements, selection criterion not developed through public, transparent process.
   - Yielded process with multiple opaque determinants that made participation difficult.
2. No identification of a trigger or explanation of how the utility would dispatch the resource.
   - Impossible to sign up customers with a blind trigger and no market experience as to how frequently or under what conditions the resources will be dispatched and yet resource is responsible for market performance of the resource and penalties from the CAISO.
   - Utility has full discretion on when the resource will be dispatched and DR provider does not know until 20 minutes in advance.
3. Utility changed the notification period from one hour to 20 minutes with no ability to negotiate and based solely on the direction of CAISO.
   - Section 1.6 of LCR RFO Pro Forma.
   - Significant change with insufficient process.
4. Sellers were responsible for all the telemetry and integration costs, which were unknown at the time of the RFO.
   - Very challenging to negotiate a contract and be on the hook for things that are not understood, not defined, unknown, or subject to change during the negotiation.
5. To the extent that the utility incurred CAISO charges, the utility could pass those charges through to the seller without identifying whether buyer or seller caused the penalty.

6. Sellers had to ensure resources would meet RA even though the RA rules were under development at the time of the RFO.

Two solutions were offered up by the sub-team, but there was not a consensus on either solution. These proposals are included below, denoted by the level of support.

Non-consensus majority:

A transparent, collaborative negotiation with buyers and sellers at the table would result in a more workable contract as opposed to developing a "take it or leave it" contract for new product pro forma contracts.

Define the following in advance of conducting an auction/issuing an RFO:

- Resource attributes
- Locational requirements
- Telemetry and Integration requirements and costs
- Triggers, if not bid in directly by DR provider. DRAM allows DR providers to submit bids and be dispatched based upon whether the bid clears in the wholesale market. This is an advantage as there are no surprises. If a bid is selected in Day-Ahead market clearing process, DR provider knows it has to dispatch resource the following day.

Non-consensus minority:

1. A standard contract should be developed through a process at the Commission. DRAM was cited as a good example.

2. A technology agnostic pro forma should be developed.

Additional Discussion

The DRAM example was commented upon by various members of the sub-team as not being applicable. The DRAM contract was for a product that was much more standard (RA) than the products associated with a distribution deferral.

During the CSFWG meeting, there was a discussion of the integration of DERs and whether or not individual offers needed to be integrated or if a portfolio of offers could be considered integrated.

- This discussion lead to the non-consensus minority recommendation to develop a technology agnostic pro forma contract.
- A barrier to the integration of technologies was suggested to be the lack of existing measurement and verification approaches for technology agnostic offers.

  - This barrier was noted to be a result of not only the differences in DER technologies, but also due to differences in existing DER policies (namely DSM program policies). The result of these two factors leading to different M&V approaches being used in past solicitations.
- There also was a suggestion that the IOU solicitation materials should encourage DER portfolios, and that there be strong DPAG and DPRG oversight to ensure transparency in selecting the winning portfolios or combinations of individual DERs (if the utilities structure the portfolios themselves).

After the meeting, a few additional considerations for the distribution deferral changes were offered up by CSFWG participants. These are included below:

- Pre-operational milestones could include development milestones and testing milestones. See also performance requirements and measurements in the Services element section.
- For development security/performance assurances, there is a need to consider costs to the IOU for DER development delays and ultimately potential seller failure to implement DER.
- Increases to performance assurance for the following reasons should be considered:
  - Potential damages faced by IOU if DER does not perform or other mechanisms for IOU to recover such damages from seller, *e.g.*, indemnity.
  - Potential damages for lost service.
  - Potential damages to IOU equipment or infrastructure.
  - Impacts affecting the IOU's ability to timely meet the distribution constraint if a DER fails to come online or to perform to expectation.
- In addition to increases in performance assurance, the contracts would need to consider changes to insurance requirements for DERs and the distribution system.
- An additional category of "requirements for the DER to comply with particular IOU standards" was suggested. The details would need to be developed, but would likely include technical, interconnection, and safety standards.

During the discussion at the final CSFWG meeting, there was a significant discussion on the process around bidding and the process around contracting. The following process was written and is provided as an overview of the process typically used.

Solicitation is launched and includes:

1. Defined attributes being sought

    a. Quantity of capacity, energy and voltage support resources

    b. Minimum locational requirements

    c. Other locational preferences

    d. Required on-line date for resources

2. Eligible resources
3. Pro forma contracts or term sheets
4. Bidders template to be filled out providing the details of the offer

By the bid date, bidders:

1. Fill out template
2. Complete mark-up of pro forma contract or terms sheets

After bids are received:

1. Utility reviews bids to ensure that the product being offered is clear
    a. Attributes offered and their location
    b. Quantity of attributes offered
    c. On-line date of attributes offered
    d. Any constraints to utilizing the resource
        i. Hours per day/time of day
        ii. Usage per period (day/month/year)
    e. Confirm that some attributes offered conform with the attributes being sought
2. Valuation of each offer to enable short list selection of resources
3. Determination as to whether the resources offered can meet the near-term need

After short listing:

1. Negotiate terms and conditions with selected parties

Final bids:

1. Final price based upon the product, volume and terms in the negotiated contracts
2. Final valuation to select the optimal portfolio to provide the required attributes
3. Execute selected contracts

F. Outreach

Summary of Progress

This topic was split into two categories of outreach: market and customer. The CSFWG was able to reach consensus on the market outreach, identifying that existing market outreach practices meet the needs of the market. The CSFWG was unable to reach consensus on the topic of customer outreach. Three layers of customer outreach, including customer acquisition, were identified and included in this report.

Consensus Items from Status Report

The CSFWG agreed that existing market outreach is a good starting point for market outreach. The CSFWG also agreed that market outreach during the regulatory design phase was important. A number of stakeholders mentioned that it would be useful to add customer outreach as part of the discussion.

Recommendation from Sub-Team 6

The earlier discussions of the CSFWG determined that there is a need to be transparent regarding the support IOUs will provide in terms of general customer awareness in the targeted areas, as well as any post-contracting support the IOUs will provide in the customer acquisition process for behind-the-meter DERs. The level of customer awareness and customer acquisition support that IOUs will provide may materially impact vendor bids into the solicitation; therefore, it is important for the solicitation documents to contain this information.

The sub-team members on customer engagement explored these issues and the recommendations below that represent suggestions from either multiple or individual sub-team members. Three illustrative proposals for customer outreach were also developed by either multiple or individual members of this group and are included in this report as Appendix 5.

There was consensus from sub-team 6 and the larger CSFWG participants that a utility should include information describing a baseline level of customer engagement support within the solicitation documents. This description would outline current Commission rules and IOU standard practices for both pre-contracting and post-contracting acquisition of customer specific data in the targeted locations. This description would include elements of Proposals A and/or B in Appendix 5.

<u>*Utility Customer Engagement prior to contracting with an RFO winning bidder:*</u>

There was consensus expressed regarding the following elements of customer engagement support from the utility that would be available to the winning bidder before contracting with a winning RFO bidder:

- The RFO software will include information regarding the specific geographic area where resources must be deployed in order to provide the distribution services that are being contracted for in the solicitation. The RFO software will also include information on the customer composition in the area covered by the RFO to the extent

that this information does not violate Commission customer privacy rules (this was an element of Proposal A in Appendix 5).

- The RFO software will include information regarding how vendors can request customer specific information under current Commission customer privacy rules. Access to data used in the RFO associated with these first two bullets generally requires an interested RFO bidder to acquire a logon from the utility and to execute a Non-Disclosure Agreement (NDA).

- The IOUs will develop and maintain a customer facing web presentment during the RFO period in order to increase customer awareness in the areas covered by the RFO and to inform customers that they may be contacted by vendors and what the purpose of those contacts. This is an element of Proposal B in Appendix 5.

Utility Customer Engagement after contracting with an RFO winning bidder:

There was also consensus expressed regarding the following elements of customer engagement support by the utility that would be available after contracting with the winning bidder:

- Information regarding the level of enhanced post-contracting support that the utility is willing to offer to the winning vendor(s) should be included in the RFO process, as well as the criteria and cost (if any) of utilizing that offered enhanced post-contracting support.

One of the proposals (Proposal C in Appendix 5) developed by members of this sub-team focused on the level of support utilities could offer to aid an RFO contracted vendors' pursuit to acquire customers to participate in the vendor's offered solution. Sub-team and full team consensus was reached that a RFO contracted vendor would likely benefit from utility provided post-contract signing customer outreach, but consensus on any details of such outreach was not achieved, in part because aspects of this proposal conflict with existing business practices of each of the utilities, and the focus of the CSFWG did not include, nor was sufficient time allocated, to discuss new business models. Certain aspects of this proposal are described below.

Sub-team and full Working Group consensus:

- There was general support for some level of enhanced post-contracting customer support as contained in Proposal C. However, there was no consensus around, in particular, what the menu of options should be and how the cost of providing those enhanced options should be recovered. Notwithstanding these areas where there was no consensus reached, there was consensus reached regarding the need to include the level of support the IOU will provide and the terms and conditions of accessing that support in the RFO software/documents.

Suggestions by sub-team member(s) that did not receive sub-team or Working Group consensus:

- After the RFO period, the IOUs will reposition the RFO customer facing web presentment to reflect the results of the RFO and call out in some fashion the vendors who may be contacting them and what services those vendors have been contracted to supply under the RFO.

- Items to include in a utility offered post-contract signed customer outreach services and how the cost associated with providing those offered services should be recovered. Options discussed include:

  - Use of IOU corporate logo on vendor's marketing materials in the RFO area: There was no consensus reached on whether there was a need for standardized language around use of the IOU corporate logo across the IOUs or whether there would be a fee charged for use of the corporate logo by vendors for this purpose.

  - Development of qualified leads for winning vendors and/or joint meetings customer meetings with vendor and IOU Customer Relationship Managers: As with the use of the corporate logo by winning bidders, there was no consensus reached regarding standardization of terms and conditions for accessing these services across the IOUs or whether these services would be provided at a fee.

  - Additional enhanced customer acquisition support: There were additional CSFWG participant ideas around potential additional support beyond the support that IOUs have provided for "implementation partners" EE as discussed above; however, there was no consensus reached on any of those suggestions.

Additional Discussion

No additional discussion was offered for this topic.

Non-Element Discussions

In the initial CSFWG meetings leading up to the Status Report, a number of other topics were identified as topics for the CSFWG to discuss. These topics were also the focus of sub-team discussions and recommendations were provided by those sub-teams. This section covers those sub-teams, and their recommendations, which did not directly support one of the Scoping Memo and Ruling elements.

A. Distribution Loading Order

Summary of Progress

The CSFWG discussed the topic of applying the Energy Action Plan's Loading Order to solicitations for distribution deferrals. The CSFWG was able to reach consensus that it should not apply.

Recommendation from Sub-Team 3.a

With regards to the competitive solicitation framework and the procurement of distributed resources under the DRP, sub-team 3A reached a consensus that the existing state Loading Order[14] did not seem applicable (at least at this time). Rather, the sub-team consensus was that the appropriate model would be to use Public Utilities Code Section 769 as the guide for the competitive solicitation, unencumbered by the Loading Order, coupled with a "net benefits test" to determine which bids should be selected in the competitive DER solicitations. In the future, for example when distributed resources are competitively procured in the context of all-source solicitations or when DER resources are evaluated against non-distributed resources, then the role of the Loading Order may need to be addressed.

Additional Discussion

A suggestion from the CSFWG was incorporated into the recommendation to clarify the scope of the discussions to be applicable to only the Energy Action Plan's Loading Order concept, and not apply to other "distribution loading order" concepts that exist.

B. Non-IOU LSEs

Summary of Progress

The CSFWG had previously identified the need to discuss the interaction of the solicitations being contemplated with non-IOU LSEs. A sub-team was formed to discuss this topic, but was not able to reach consensus. The topic of Community Choice Aggregators (CCAs) participating in solicitations was near consensus, but the topic of IOU-CCA partnerships was not near consensus.

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[14] The discussions of this sub-team were solely focused on whether or not the Loading Order, as defined by the 2003 Energy Action Plan, should apply to procurement focused on distribution deferral needs. The recommendations only apply to that specific policy.

Recommendation from Sub-Team 7

This sub-team was formed with the intention of addressing potential market challenges which are unique to the creation of robust DER markets within CCAs' territories. There was no consensus on this sub-team's recommendations. This sub-team developed two sets of recommendations: (1) ability of CCAs to participate in competitive solicitations, and (2) formation of partnerships between IOUs and CCAs. Both recommendations were a minority non-consensus, as described below in the additional discussion section.

Recommendation 1: CCAs Participating in Competitive Solicitations

CCAs are equally eligible to provide non-wire DER services as other market participants. Should a CCA decide to participate in a competitive solicitation process, a CCA would have the ability to do so and be subject to the eligibility criteria for other participants. Such criteria are developed on a case-by-case scenario, and the process is subject to oversight mechanisms developed by a separate sub-team that is focused on oversight. Participation in the competitive solicitation does not preclude a CCA from administering other CPUC-approved programs.

Various, specific, issues were identified associated with this recommendation. These are included in Appendix 7.

Recommendation 2: Formation of New Partnerships

Incremental Improvement Proposal 1: Overcoming past obstacles; building off recent successful negotiations

IOUs and CCAs have developed procedures to address implementation issues as they arise. Should implementation issues arise in the competitive solicitation framework, including matters related to CCA Code of Conduct, double-counting, and oversight, these issues should be resolved on a case-by-case basis relying on existing Commission decisions and resolutions, as well as recommendations developed by the CSFWG.

In addition, Marin Clean Energy (MCE) and Sonoma Clean Power (SCP) have entered into settlement with PG&E on the Charge Smart and Save Program, PG&E's electric vehicle infrastructure and education program. This settlement, once approved by the CPUC, should provide a positive example for partnership, allowing PG&E and the CCAs to identify implementation challenges and resolve these issues through existing communication channels between these entities.

There was robust support for this "business as usual" approach, yet consensus was not expressly reached.

"Enhanced" Proposal 2: Developing a partnership model for optimization and coordination

Public Utilities Code Section 769 establishes that the electrical corporations' DRPs should "propose cost-effective methods of effectively coordinating existing commission-

approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources."

In the sub-team's work, and further contained in public information, it has been established that certain existing and developing CCAs wish to enhance local reliability and resiliency in addition to addressing the local community's GHG goals. For example, one of the avenues proposed is to create new, targeted CCA IDER programs, yet to be developed, possibly as CCA IDER Program Administrators.

There are significant, inherent public benefits which can be realized by CCAs or Local Government Partnerships (LGP), including the potential for strong community interest/involvement in programs due to shared customer values, plus potential for enhanced customer value through targeted projects at critical infrastructure and integration of land use and demographic data. Conversely, IOU value-enhancement includes "legitimizing," *e.g.*, through co-branding of products or programs through strong name recognition and the potential for collaboration in locally-targeted programs, including sharing of certain data, marketing and outreach. It remains an open question how the market would function in some scenarios.

There are apparent challenges which CCAs may currently face when implementing local IDER programs. Among these challenges are the potential for developing local programs directed at solving a distribution system need, while the IOU is simultaneously developing an RFO to address the same need. Without adequate understanding of the activities of the other party, a "too many cooks spoil the broth" outcome may occur, resulting in wasted resources and decreased cost-effectiveness.

Another challenge for CCAs is to capture the realized benefit of a local IDER program through Evaluation, Measurement &Verification activities: A locally-targeted set of DERs may not carry verifiable benefit simply because the CCA has no way of accurately measuring the effectiveness of the effort under the "business as usual" framework.

In this new energy future, who will be ultimately responsible for ensuring the customers have access to reliable and affordable power (CCAs or IOUs or others)? How do we delineate the roles and responsibilities of distribution, supply, demand and overall coordination? In this context, which entities will be bidders, and which will develop programs and RFOS?

To address these and other issues, "Enhanced" Proposal 2 is issued for consideration:

The Commission should authorize CCAs and IOUs, should they so wish, to voluntarily form an umbrella partnering entity, unique to each composite aggregation, for purposes of optimizing mutual benefit and achievement of efficiencies in implementing state and commission policies relating to GHG goals, robust proliferation of DER markets, and the implementation of certain other policy objectives of Public Utilities Code Sections 769 and 381.1, as well as Senate Bill 350, for the purposes of coordinating efforts including but not limited to Integrated Resource Planning, resiliency efforts and EE goals.

The partnership agreement for this entity would contain terms intended to maximize public benefit from the strengths of both entities, or at a minimum, to ensure IOU and CCA

programs are not functioning at cross-purposes. Such partnerships could be formed with local governments at any level, similar to an LGP, but with expanded and independent duties.

The benefits to participating IOUs may be captured in enhanced incentive levels collected through a specific CCA customer tariff, to be negotiated between entities in advance, intended to be cost-effective to customers overall.

For existing or newly-formed CCAs choosing not to form such IOU partnerships, should reporting metrics show performance relating to state objectives including DER proliferation in CCA territories to be sub-optimal in ex-post evaluations, the Commission could consider mandating the formation of a partnership in such cases.

This "Enhanced" Proposal 2 was seen as somewhat controversial in the sub-team discussion, partly due to lack of specific partnering structure detail. However, as written, specific terms would be negotiated uniquely to each partnership. While consensus was not reached, there was some support for an optimization structure such as this proposal.

Additional Discussion

The majority of CSFWG participants did not object to Recommendation 1. However, consensus was unable to be achieved due to concerns with the potential for CCAs to have access to information, due to their role as a program administrator, which other market participants would not have.

The majority of CSFWG participants felt that the Recommendation 2 was out of scope for this effort and should not be included. A minority of CSFWG participants felt that, although potentially out of scope, that the issues surrounding Recommendation 2 were significant enough to include the recommendation in the report.

Appendix 1: Other Items from Status Report

Preliminary Consensus Items

1. **Scope of the Working Group:** The CSFWG will develop a framework for one type of sourcing mechanism – competitive solicitations. Mechanisms or issues that pertain to non-bid procurement are considered out-of-scope. It was important for the group to recognize that a solicitation typically entails competitive bids, so anything that pertains to non-bid procurement is outside the scope of the Working Group.

2. **Direct Customer Participation in a Distribution Need:** The concept of meeting a need identified by a customer was discussed during a CSFWG meeting. The Working Group agreed that this topic is not in scope for the CSFWG, but may be more appropriate for the DRP.

3. **The role of bilateral contracts:** Bilateral contracts are out-of-scope, but should be considered as part of broader scope of the IDER proceeding as it considers other sourcing/deployment options.

Preliminary Items Requiring Additional Discussion

1. **Role of the DRP, DPP, and the Working Group:** The IOUs' annual Distribution Planning Process (DPP), which incorporates aspects of the DRP such as Integration Capacity Analysis (ICA) and Locational Net Benefit Analysis (LNBA), will determine distribution needs and the timing of solicitations. A full understanding of how these work areas interact will require a greater level of detail. Additionally, it will be important to consider the role of "review groups," e.g., Procurement Review Group (PRG) or Distribution Planning Review Group (DPRG), in both the planning and procurement processes.

2. **Services beyond what the IOUs state is needed:** The discussion noted that the need identified through the DRP or DPP may not be inclusive of all potential services a DER solution could provide. The CSFWG discussed ways for these additional services to be considered, but did not reach a consensus. This could include data.

3. **Distribution Loading Order:** The CSFWG discussed whether or not a loading order for procurement of DERs should apply to these competitive solicitations. The CSFWG agreed that this item needs to be included in discussions moving forward.

4. **Role of CCAs and/or other non-IOU LSEs within a local competitive solicitation framework:** The CSFWG agreed that this is a consideration that ultimately should be addressed and proposes that this be included in future work of this or successor proceedings.

5. **Resource eligibility of products: Inclusive of fossil fuel-fired resources?** The CSFWG did not reach consensus on this topic, but feel that it should be considered moving forward. The Assigned Commissioner's Advisor remarked that this topic was initially addressed in the DRP Scoping Memo, permitting these resources, so long as they reduce

greenhouse gas emissions. He also stated the CSFWG could revisit, if needed, but it should not be a focus for the group. As the details of a solicitation are worked through, including what resources can meet the needs, this topic may be readdressed.

6. **Spectrum of Oversight Topics:** The CSFWG agreed that depending on the circumstances, different levels of oversight may be required. However, this will require more discussion to understand how the oversight is applied. Key topics to be addressed included:

    a. Independent Evaluator: Selection and approval process of an Independent Evaluator.
    b. Type of PRG consultation requirements (e.g., defining market and non-participants, members of group, procurement scale, timing and level of consultation), and reasonableness of this function relative to the cost, skills required, and scale of distribution alternative DER possibilities.
    c. Distinguishing between contract approval and funding approval.

7. **Time required for solicitation needs to be considered:** The lead time and implementation time for solicitations can impact the decision to use a solicitation or not (i.e., sourcing also plays a role in deferral viability). This needs to be explored in more detail. Potential ranges, as well as solutions (e.g., bundling needs into larger solicitations) need to be captured. This item was also identified during the rules and principles discussion and may fit better within that element.

8. **Incrementality, Double-counting:** The need to ensure that all DERs solicited are accounted for accurately and avoid "double-counting and payment" was discussed. This is something that past competitive solicitations, e.g., SCE's LCR RFO, have encountered and needs to be considered for these solicitations. CSFWG members were not able to identify solutions to this issue, so it should be discussed further. The future CSFWG discussions should discuss when this applies, as well as ways to solve this potential issue.

9. **Valuation Criteria:** DER competitive solicitation should seek balance between quantitative and qualitative evaluation criteria included. DERs can provide value in addition to what is being procured and the additional value should be used in the evaluation of which DER option meets the LCBF framework in as transparent of a manner as reasonable. The CSFWG will need to work through examples to advance discussion.

10. **Reliability and Performance Requirement Issues:** The CSFWG agreed that this topic needs to be discussed further, and that an example could support those discussions. A few key topics for future discussion:
    a. DER solutions will need to assure performance and support reliable operation of the grid.
    b. Procuring DER solutions may involve some transfer of risk to the DER service provider.
    c. DER service providers may desire flexibility of solution to manage risk.
    d. Different DER solutions may address risk to varying degrees based upon the characteristics of each DER.

11. **Local Reliability and Cost Effectiveness with Multiple LSEs:** This topic is one for the CSFWG to consider. It was noted that this is likely not an immediate concern.

12. **Level of detail in the definition of service to be sourced:** How a need is translated to a service definition should be explored further. Concerns were stated with how this will be done. The general concepts were discussed in CSFWG meeting #1, but how to apply those concepts was not flushed out.

13. **Critical areas of pro forma contract to be developed:** Three components of the pro forma contract were identified as needing to be tailored for DER deployment to meet distribution grid needs: risk allocation; measurement and verification (M&V); and how to describe the need, including a discussion of portfolio and non-portfolio solutions.

14. **Using examples to guide discussion:** The CSFWG discussed how to develop a general framework, such as common terms, then use examples to create enough detail to show how the framework could be used for future solicitations.

Appendix 2: Services Details

Examples of Distribution Services, Attributes and Performance Requirements
To better articulate the concepts for distribution services, attributes and performance requirements, the following hypothetical examples have been developed to further describe these items. Specifically, examples for services, attributes and performance requirements have been developed for the following:

A. Distribution Capacity Services
B. Voltage Support Services
C. Reliability (Back-Tie Capacity) Services
D. Resiliency (Microgrid) Services

Example A: Distribution Capacity Services

Background:
Electric Distribution Planning analysis has identified that a distribution substation transformer is projected to overload in year 2019 during summer peak demand conditions. Specifically, this distribution substation transformer is projected to serve a peak demand of 13.2 MW, which exceeds this transformer's thermal capacity rating of 11.88 MW by 11%. Hence, this transformer is projected to overload by 11% under these peak demand conditions. Furthermore, additional Distribution Planning analysis has projected that this overload may reach up to 22% by year 2020 for summer peak demand conditions. The following schematic illustrates this example.

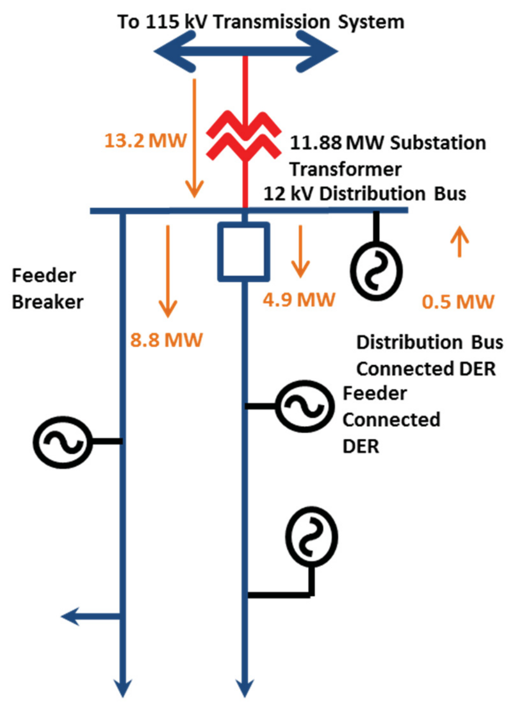

Figure 1: Example of Projected Substation Transformer Overload

Distribution Capacity Service Requirements and Associated Attributes
To ensure safe and reliable electric service, additional distribution capacity is required for this transformer. This additional capacity can be achieved through a traditional "wires" alternative, which in

this case would be the addition of a new substation transformer, or via a DER alternative that effectively reduces this transformer's net loading to be within its thermal rating. The associated attributes for DERs to provide distribution capacity services for this location can be described using the four Distribution Services principles described earlier, which were:

1. Location of where distribution service is provided by DERs
2. Timing of when distribution service is provided
3. Magnitude of DER Output
4. DER Availability and Assurance of Ability to Provide

Location of Where Distribution Service is Provided by DERs

For this example, to address the projected overload of this transformer, DERs would need to be located and interconnected off the electrical system "downstream" of the overloaded transformer. This is depicted as the area in the blue shade in Figure 3. Essentially, for DERs to be effective in reducing loading on this transformer, they would have to be interconnected within this location.

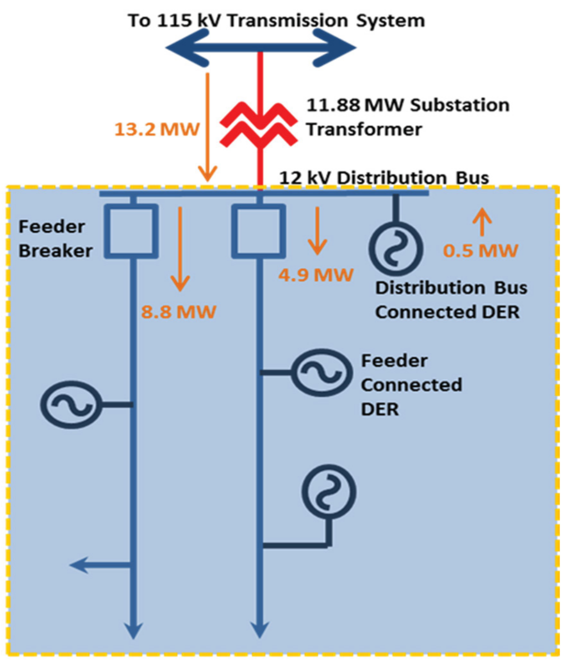

Figure 2: Example A - Location Shaded in Blue Depicts where DERs are to be located

Timing of when Distribution Service is Provided

Through additional Distribution Planning analysis, the projected overload condition in 2019 is forecast to occur during the summer months of August through September. Furthermore, additional analysis around the timing of this overload reveals that it is projected during the hours of 15:00 to 20:00 for weekdays and weekends during those months.

The following chart illustrates the projected demand loading of this transformer for the summer months of August to September.

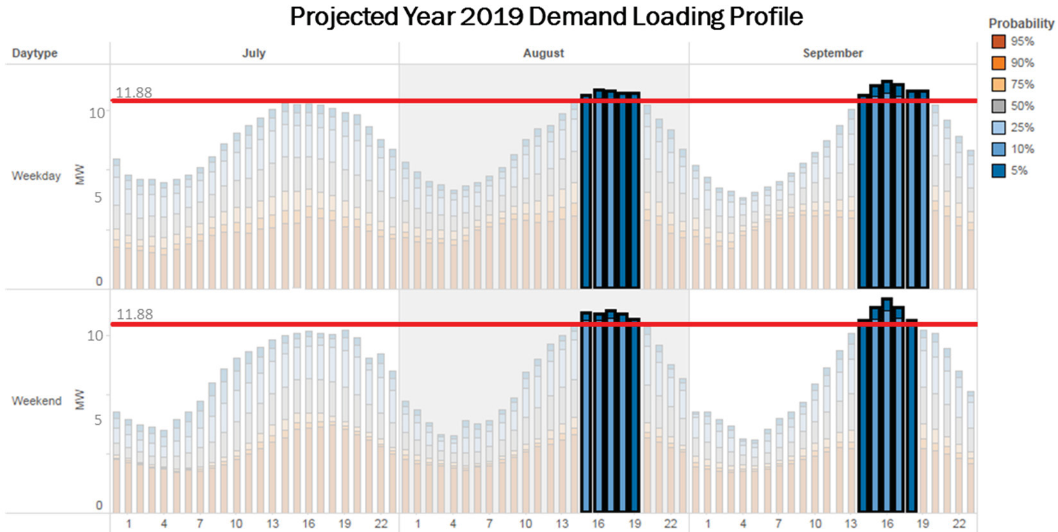

Figure 3: Example A: Projected Substation Transformer Loading during Summer Months of July - September

Level of DER Services Provided

For this example, the amount of DER response that is required is 1.4 MW during the time frame specified. The following table summarizes the attributes sought from DERs to successfully provide distribution capacity services for this transformer. Specifically, this table includes the required amount of DER response (MW and MVArs) and associated timing and frequency.

Table 1: Distribution Capacity Service Attributes

DER Attributes to Procure	YEAR				
	2017	2018	2019	2020	2021
Distribution Capacity Need (MW)	-	-	1.4	2.6	3.6
Distribution Capacity Need (MVAR)	-	-	-	-	-
Months when needed	-	-	Aug-Sept	Aug-Sept	July-Sept
Days when needed	-	-	All	All	All
Time when needed	-	-	15:00-20:00	14:00-20:00	14:00-20:30
Duration (hours/day)	-	-	5	6	6.5
Frequency of Need (days/month)			1	3	5

For this example, the amount of DER response increases from 1.4 MW to 2.6 MW by year 2020. Furthermore, as demand continues to grow, by year 2021 the amount of DER response increases to 3.6 MW with the time frame and duration of DER response also expanding.

In addition to the level of DER response that is to be provided, the utility may require that the level of DER response be provided within a certain time frame. For this distribution capacity services example, under projected 2019 conditions, the utility may require that within 30 minutes following a utility command signal to the DERs, the DERs are to reach the desired full output of 1.4 MW for a duration of 5 hours per event.

DER Availability and Assurance of the Ability to Provide
For DERs to successfully provide distribution capacity services, DERs will need to ensure their availability to timely and reliably respond to utility control signals for providing the necessary output. As discussed previously, the utility may require that DERs demonstrate performance and measurement requirements around availability and assurance during various phases of the DER contract delivery term. These performance and measurement requirements include meeting pre-commercial milestones, satisfactory results with DER commissioning, satisfactory periodic distribution service testing, and satisfactory distribution service performance for an event. For this example, the following figure illustrates how the various tests that the utilities may require demonstrating DER availability and assurance.

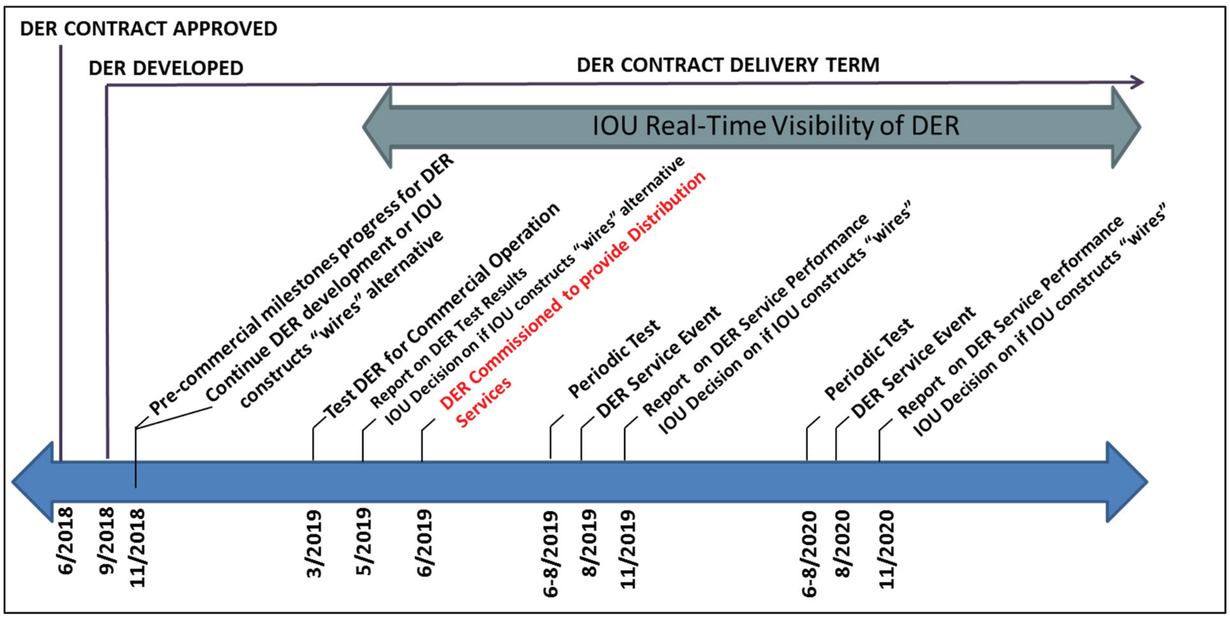

Figure 4: Example A -Schedule of DER Availability and Assurance Requirements

For this example, the distribution capacity service need date is for July 2019. The DERs are to be commissioned in June, a month prior the July date to allow for any potential slippages. Prior to the DER distribution services commissioning date, the DERs are to be tested to ensure DERs are responding to utility test control signals timely and at the required amount and for the desired durations. The utility will to assess the results of the DER testing and determine if a contingency plan would be needed prior to the July 2019 date. If a contingency plan is required due to the results of the DER performance, the utility may develop alternate plans, such as requiring temporary mobile generation to provide the distribution services until the utility can develop the "wires" solution or have the DER developer correct their DER performance deficiencies.

Example B: Voltage Support Service

Background
Electric Distribution Planning utilizes modeling tools to perform power-flow studies of the distribution system simulating electric grid performance. The loading values inputted for each distribution feeder are based off of forecasted values. The 2016 results from the power flow identified a feeder with steady-state

voltage below the CPUC Rule 2 limit at specific sections on a highly residential feeder. Furthermore, recorded data for this feeder revealed a power factor below industry electric system reliability standards. The area in question is also forecasted to incur future residential development in the next several years increasing the demand and reducing the voltage further. The following schematic identifies the distribution feeder forecasted to have voltage violations during peak conditions.

Figure 5: Example of a Distribution Feeder with Voltage Limit Violations

Voltage Support Service and Associated Attributes

To ensure safe and reliable electric service as well as maintaining compliance with CPUC Rule 2 voltage limits, additional reactive resources are required. A traditional "wires" solution to provide additional reactive resources is installing a switch capacitor on the feeder or installing a voltage regulator. Another alternative is interconnecting DERs to provide reactive resources effectively acting as a capacitor either when requested by the utility or provided with a required operating profile. The DER reactive resource could be from an individual resource and/or aggregated resources capable of dynamically and demonstrably providing reactive power. The associated attributes for DERs to provide reactive power for the feeder can be described using the four Distribution Services described above.

Location of Where Distribution Service is Provided

For this example and similar to the Example A, to address the voltage violation DERs would be required to locate and interconnect to the electric system upstream of the voltage violation occurrence identified by the utility. The location for the voltage violation is depicted as the area in blue within the following figure. For DERs to be effective in providing additional reactive resources, interconnection in the area in blue is required.

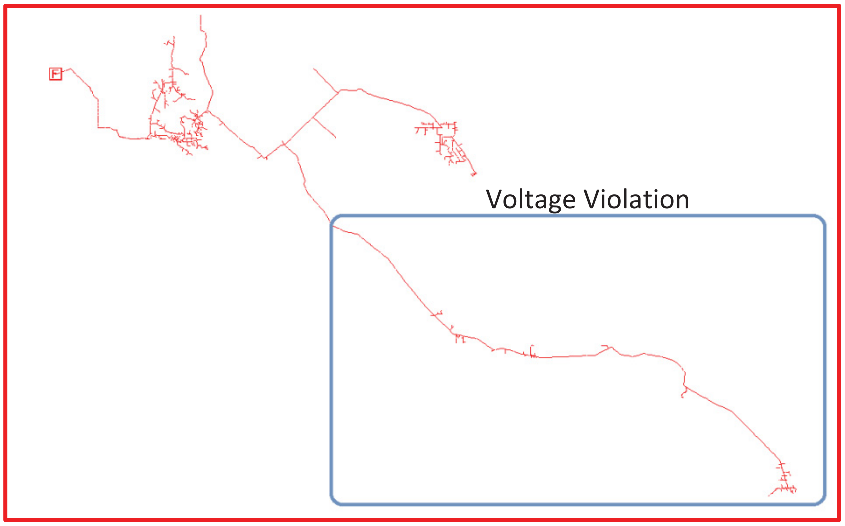

Figure 6: Example B - Location within Blue square Depicts where DERs are to be located

Timing of When Distribution Service is Provided

During the Distribution Planning analysis, results from the power-flow model inputting adverse forecast values projected a reactive resource deficiency during peak conditions starting in year 2017. The peak conditions are expected to occur during the summer months of August through September. Additional analysis reveals an operation of DERs providing additional reactive resources are required to occur during the hours of 13:00 to 20:00 for weekdays and weekends during those months. Due to projected demand growth over the next several years, this reactive resource deficiency is expecting to increase over time. Furthermore, the associated time and time duration of the need will also change, which will be further described in the following sections.

Level of DER Service Provided

For this example, the amount of DER response required during the specific time frame is 0.6 MVArs. The following table summarizes the attributes from DERs to successfully provide an additional reactive resource. Specifically, this table includes the required amount of DER response and associated timing as well as frequency.

Table 2 Distribution Voltage Support Attributes

DER Attributes to Procure	YEAR			
	2017	**2018**	**2019**	**2020**
Distribution Capacity Need (MW)	-	-	-	-
Distribution Capacity Need (MVAR)	0.6	0.65	0.7	0.7
Months when needed	Aug - Sept	Aug - Sept	Aug - Sept	Aug - Sept
Days when needed	All	All	All	All
Time when needed	13:00-20:00	12:30-20:00	12:00-20:30	12:00-20:00
Duration (hour/day)	7	7.5	8	8
Frequency of Need (days/month)	2	4	6	6

As stated previously, the feeder is expecting to see growth in the next several years; as a result the reactive power deficiency and associated time are increased in the table from 0.6 Megavolt-amperes reactive (MVArs) to 0.70 MVArs.

In addition to the level of DER response that is to be provided, the utility may require that the level of DER response be provided within a certain time frame. For this voltage support services example, under projected 2019 conditions, the utility may require that within a few seconds or faster (e.g. 6 cycles or 1/10 of a second) following a utility command signal, the DERs are to reach the desired full output of 0.7 MVArs (or 700 kVArs) for a duration of 7.5 hours per event to provide the required voltage support service to ensure customer equipment is not damaged.

DER Availability and Assurance of the Ability to Provide

For DERs to successfully provide distribution capacity services, DERs will need to ensure their availability to timely and reliably respond to utility control signals for providing the necessary output. As discussed previously, the utility may require that DERs demonstrate performance and measurement requirements around availability and assurance during various phases of the DER contract delivery term. These performance and measurement requirements include meeting pre-commercial milestones, satisfactory results with DER commissioning, satisfactory periodic distribution service testing, satisfactory distribution service performance for an event. Similar to the distribution capacity services example, the following figure illustrates the various tests that the utilities may require demonstrating DER availability and assurance for this voltage support example.

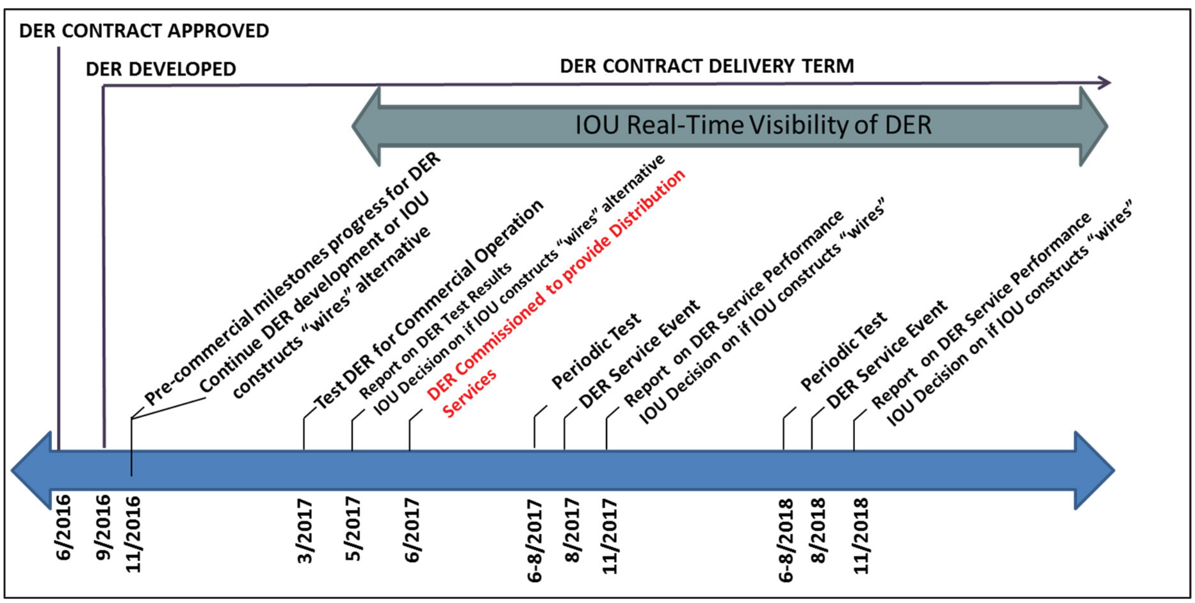

Figure 7: Example B - Schedule of DER Availability and Assurance Requirements

Example C: Reliability Services – Back-Tie

Background:

Electric Distribution Planning analysis has identified that a distribution feeder is projected to overload by year 2018 under emergency conditions when providing back-tie capacity support to an adjacent distribution feeder that has an experienced an outage. Specifically, the distribution feeder back-tie is not sized appropriately to transfer peak demand from the de-energized distribution feeder to an adjacent distribution feeder. The following figure illustrates this example.

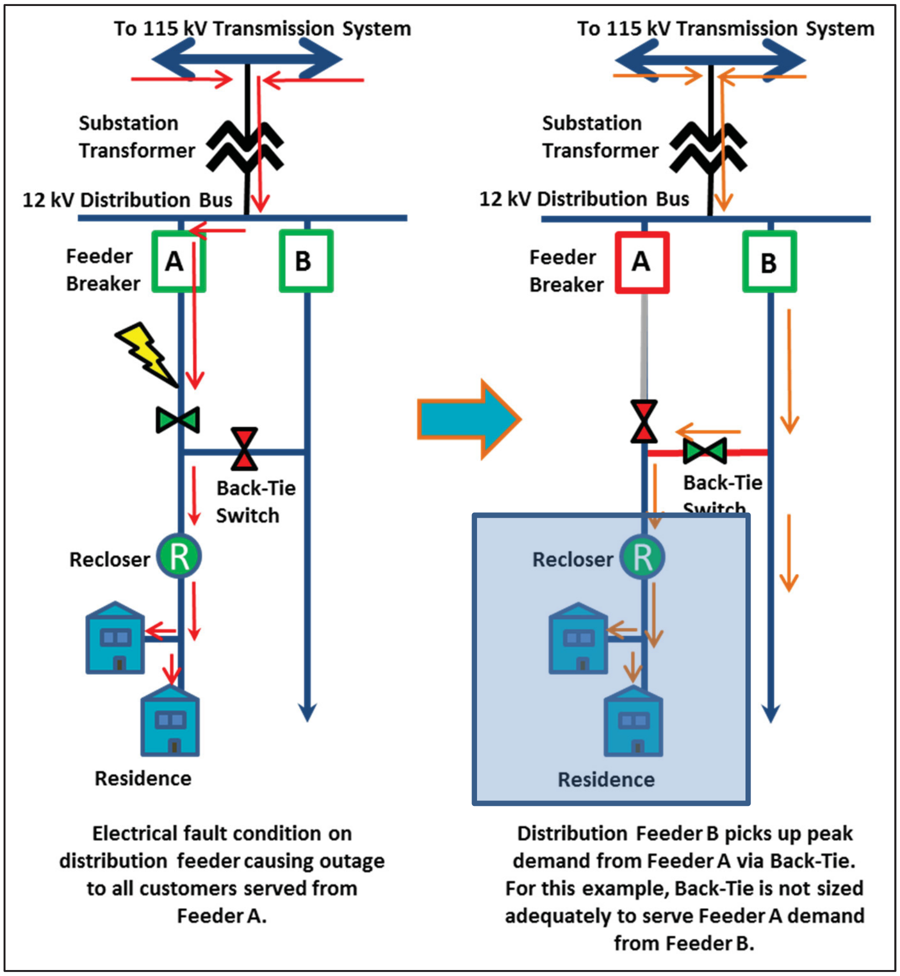

Figure 8: Example C: Back-Tie Capacity

For this example, the capacity of the distribution back-tie is projected to be deficient by 100 kW by year 2018, which is projected to increase to a 500 kW deficiency by year 2020 due to projected demand growth.

Reliability Service: Back-Tie Capacity and Associated Attributes

To ensure safe and reliable electric service as well as maintaining compliance with the CPUC Rule 2 voltage limits, additional DER resources may provide additional reliability via incremental back-tie capacity support following distribution feeder outage conditions. A traditional "wires" solution to provide this additional reliability service is to reinforce this back-tie with higher rated infrastructure,

which could include larger size electrical line conductors and higher rated back-tie switches. Another alternative is interconnecting and operating DERs to provide resources to restore service to customers either when requested by the utility or provided when a forced outage occurs and incremental back-tie support is needed to serve electric customers from an adjacent feeder. The DER resources could be from an individual resource and/or aggregated resources capable of dynamically and demonstrably providing the electrical services to customers. The associated attributes for DERs to provide resources for the back-tie support can be described using the four Distribution Services principles described above.

Location of Where Distribution Service is Provided
For this example, DERs would be required to locate and interconnect to the electric system downstream of the isolating switch, which is shown in the area shaded in blue within the previous figure. For DERs to be effective in providing this reliability service, interconnection in the area in blue is required.

Timing of when Distribution Service is Provided
Since this service is in response to planned or forced feeder outages, the operation of DERs providing this service needs to occur immediately after the outage during electric utility restoration efforts. While there may be some statistical likelihood that the outages will occur during certain periods of time, an outage may occur at any time and the resources must therefore also be available at any time.

Magnitude of DER Output
For this example, the magnitude of DER output will be needed to ensure electric service can be restored timely, safely, and reliably to serve end-users. Not achieving the desired output required from DERs would delay partial or full restoration of electric service for customers on a de-energized feeder due to not having adequate back-tie capacity support.

For this example, the amount of DER response required during the specific time frame is 0.1 MW for the years 2018 and 2019, which increases to 0.5 MW by 2020 due to projected load growth. The following table summarizes the attributes from DERs to successfully provide this service. Specifically, this table includes the required amount of DER response and associated timing as well as frequency. Note that the actual duration and frequency will be determined based upon historical and forecasted outage events.

Table 3: Reliability: Back-Tie Support Attributes

DER Attributes to Procure	YEAR				
	2017	2018	2019	2020	2021
Distribution Capacity Need (MW)	-	0.1	0.1	0.5	0.5
Distribution Capacity Need (MVAR)	-	-	-	-	-
Months when needed	-	All	All	All	All
Days when needed	-	All	All	All	All
Time when needed	-	All	All	All	All
Duration (hours/day)	-	4	4	4	4
Frequency of need (days/month)	-	-	-	-	-

DER Availability and Assurance of Ability to Provide
The reliability expectations for DER availability and assurance providing back-tie support are going to require a high degree of confidence between the utility and DER provider. As discussed earlier, since this service is in response to planned or forced feeder outages, the operation of DERs providing this service needs to occur during the outage. While there may be some statistical likelihood that the outages will

occur during certain periods of time, an outage may occur at any time and the resources must therefore also be available at any time.

Similar to the previous examples discussed earlier, the reliability – back tie services example will follow a similar availability and assurances schedule.

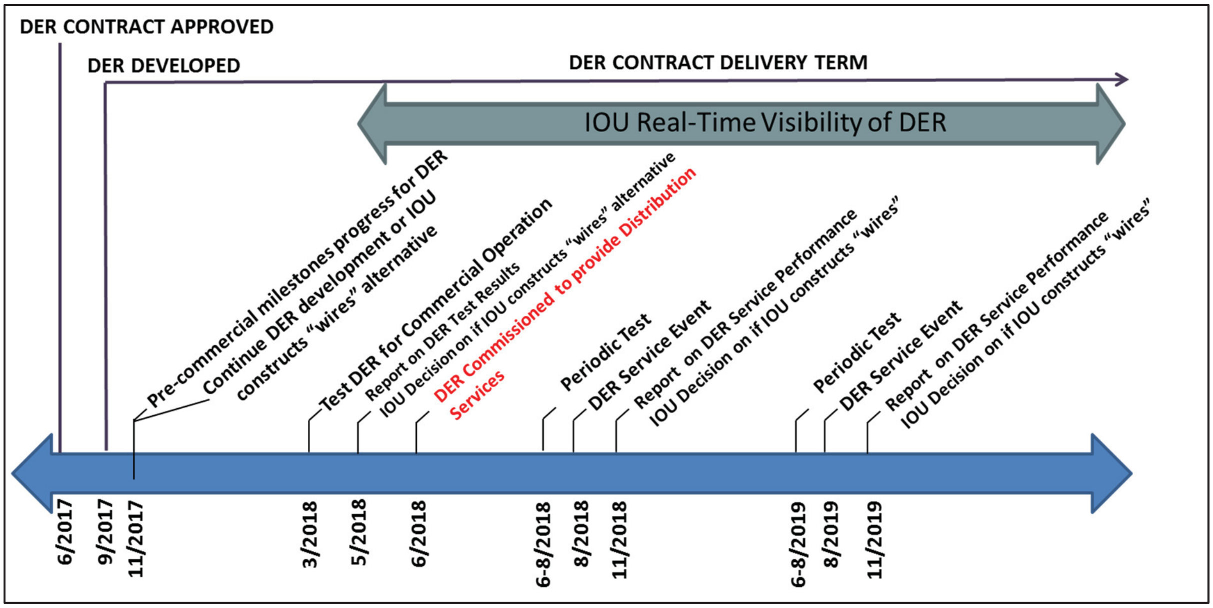

Figure 9: Example C - Schedule of DER Availability and Assurance Requirements

Example D: Reliability Services – Resiliency (Microgrid)

Background

Electric Distribution Planning utilizes modeling tools to perform power-flow studies of the distribution system simulating electric grid performance. The loading values inputted for each distribution feeder are based off of forecasted values. Under normal operating scenarios customers are provided electric service that meets Rule 2 levels of service, voltage range of 105% to 95% of nominal 120 V, with frequency typically in the range of 60 +- 0.1 Hz. When a forced or a planned outage occurs, customers will experience a loss of electrical service. If the outage occurs upstream of a sectionalizing device and there is a downstream open circuit tie as discussed in Reliability: Backup Capability, then the upstream device is opened, the downstream ties switch is closed and service is restored to customers on the non-faulted areas of the feeder. An alternative means to restore service is to create a microgrid. The following figure shows a distribution feeder with a local microgrid off a feeder branch that has the capability to restore electrical service to customers in the event of an outage to the feeder that is upstream of microgrid.

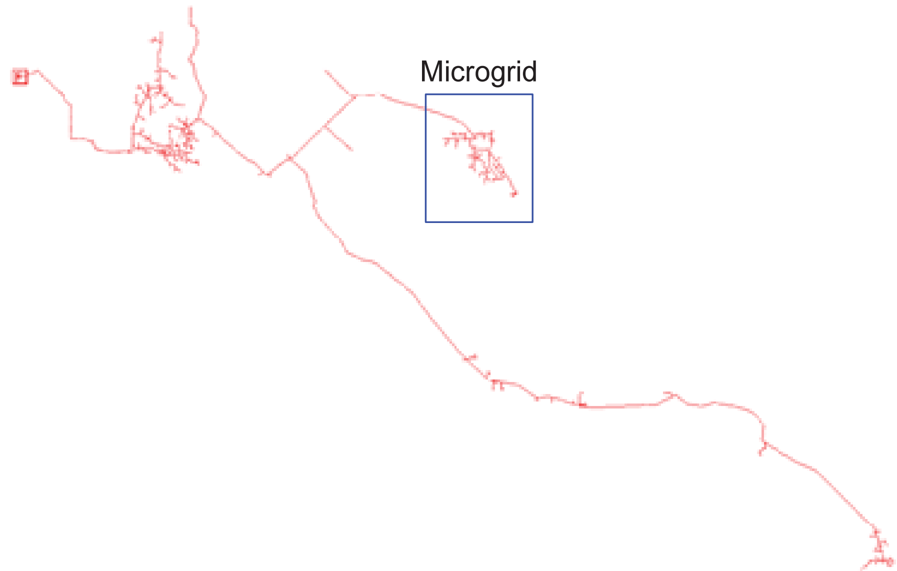

Figure 10: Example of a Distribution Feeder with a Microgrid

Reliability Service: Resiliency (Microgrid) and Associated Attributes
To ensure safe and reliable electric service as well as maintaining compliance with the mandated CPUC Rule 2 voltage limits, additional DER resources may provide resiliency (microgrid) solutions. A traditional "wires" solution to provide resiliency is to provide an alternative feed to the customers who would be impacted by an outage. Another alternative is interconnecting DERs to provide resources to restore service to customers either when requested by the utility or provided when a forced outage occurs on the feeder upstream of the microgrid. The DER resources could be from an individual resource and/or aggregated resources capable of dynamically and demonstrably providing the electrical services to customers. The generation resources must be capable of operating in isochronous mode and must have associated controls to match generation to load while maintaining voltage, frequency, and power factor and power quality within appropriate limits. The associated attributes for DERs to provide resources for the microgrid can be described using the four Distribution Services principles described above.

Location of Where Distribution Service is Provided
For this example and similar to the Example A, to restore electrical service DERs would be required to locate and interconnect to the electric system downstream of the isolating switch that disconnects the microgrid from the rest of the utility system. The location for the microgrid is shown as the area in blue within the previous figure. For DERs to be effective in providing reliability service: resiliency, interconnection in the area in blue is required.

Timing of when Distribution Service is Provided
Since this service is in response to planned or forced feeder outages, the operation of DERs providing this service needs to occur during the outage. While there may be some statistical likelihood that the outages will occur during certain periods of time, an outage may occur at any time and the resources must therefore also be available at any time.

Level of DER Service
Similar to Example A, the amount of DER response plays a significant role when ensuring the distribution system can continue to operate safely and reliably to serve end-users. Not achieving the desired output required from DERs would result in the microgrid collapsing and leaving the customers without service. The absence can lead to damaging end users equipment and affecting their usage of the electric system. For this example, the amount of DER response required during the specific time frame is 3 MW and 1 MVArs. The following table summarizes the attributes from DERs to successfully provide this service. Specifically, this table includes the required amount of DER response and associated timing as well as frequency. Note that the actual duration and frequency will be determined based upon historical and forecasted outage events.

Table 4: Resiliency Microgrid Support Attributes

DER Attributes to Procure	YEAR			
	2017	2018	2019	2020
Distribution Capacity Need (MW)	3	3	3.5	3.5
Distribution Capacity Need (MVAR)	1	1	1	1
Months when needed	All	All	All	All
Days when needed	All	All	All	All
Time when needed	All	All	All	All
Duration (hour/day)	4	4	5	5
Frequency of Need (days/month)	1	1	2	2

As discussed in the previous section, an outage may occur at any time and the resources must therefore also be available at any time. The response of the DERs in a microgrid may need to be able to respond instantaneously to ensure customer reliability and electric service is not impacted. Furthermore, as load growth may continue for certain areas served by a microgrid, the microgrid would also need to consider how this growth translates to microgrid response time and for the duration of these microgrid services. Potentially, the duration of these services may increase over time.

DER Availability and Assurance of Ability to Provide
The reliability/resiliency expectations for DER availability and assurance to provide a microgrid service are going to require a high degree of confidence between the utility and DER provider. As discussed earlier, since this service is in response to planned or forced feeder outages, the operation of DERs providing this service needs to occur during the outage. While there may be some statistical likelihood that the outages will occur during certain periods of time, an outage may occur at any time and the resources must therefore also be available at any time.

Similar to the previous examples discussed earlier, the reliability – microgrid services example will follow a similar but extended availability and assurances testing schedule.

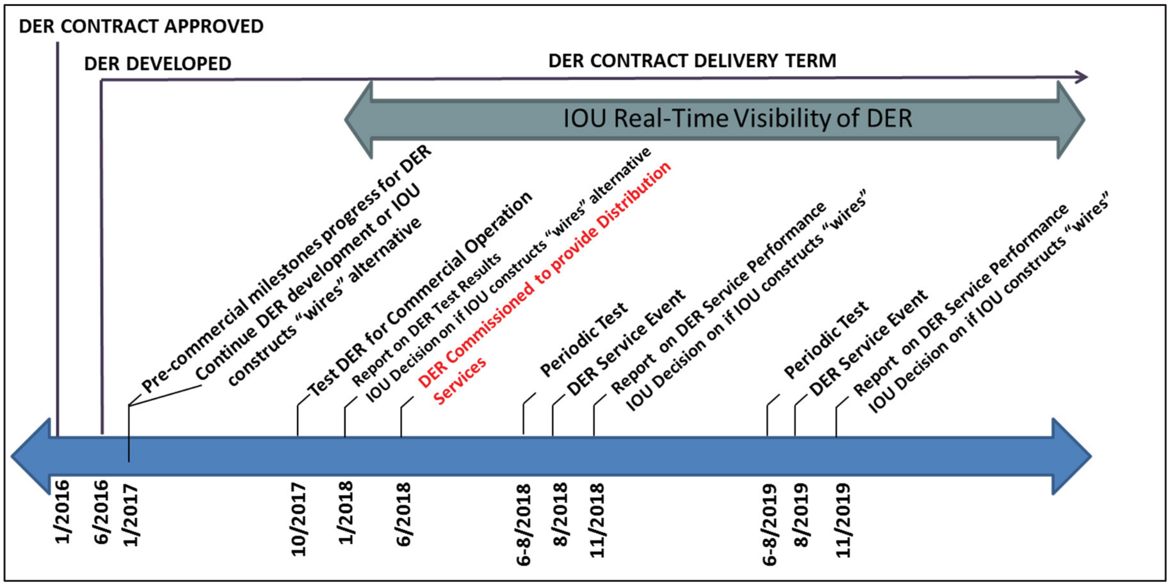

Figure 11: Example D - Schedule of DER Availability and Assurance Requirements

Appendix 3: Evaluation Methodology Details

Table 1 was developed to accompany the narrative included in the body of the report. This table includes the same valuation components described earlier, with additional categorization.

Table 1: Valuation Components

Valuation Component	Qualitative/Quantitative	Benefit/ Cost	Notes	Illustrative Applicability to Potential DERs
Resource Adequacy (RA) value benefit or reduced RA requirements benefit	Quantitative	Benefit	a. System, b. Local, c. Flexible -Modified by line losses based on DER specific location on a feeder and the time of the day profile -Modified for RA reserve margin	DG, EE, DR, ES, EV
Energy value benefit or reduced energy need benefit	Quantitative	Benefit	Use Locational Marginal Prices (LMPs) and modify by line losses for a particular location	DG, EE, DR, ES, EV
Ancillary Service (A/S) value benefit or reduced A/S need benefit	Quantitative	Benefit	TBD	TBD
Renewables Portfolio Standard (RPS) benefit or reduced RPS requirement benefit	Quantitative	Benefit		DG, EE, DR
Reduced greenhouse gas (GHG) emission	Quantitative	Benefit	Emission cost is incorporated in LMP prices	DG, EE, DR, ES, EV
Renewable Integration Cost	Quantitative	Cost	Based on CPUC methodology from RPS proceeding	DG

Avoided Sub-Transmission / Substation / Feeder Capital and Operating Expenditure	Quantitative	Benefit	Methodology being developed as part of DRP proceeding	DG, EE, DR, ES, EV
Avoided Distribution Voltage / Power Quality Capital and Operating Expenditure	Quantitative	Benefit	Methodology being developed as part of DRP proceeding	DG, EE, DR, ES, EV
Avoided Distribution Reliability and Resiliency Capital and Operating Expenditure	Quantitative	Benefit	Methodology being developed as part of DRP proceeding	DG, EE, DR, ES, EV
Avoided Transmission Capital and Operating Expenditure	Quantitative	Benefit	Methodology being developed as part of DRP proceeding	DG, EE, DR, ES, EV
Contract Payments Cost	Quantitative	Cost	Based on the contract payment structure, variable charge, and capacity prices, expected generation and contract term	DG, EE, DR, ES, EV
Societal Net Benefits	Qualitative	Benefit and Cost	DRP, DR proceeding, IDER Cost Effectiveness Phase 3 all sources for details	DG, EE, DR, ES, EV
Public safety avoided costs	Qualitative	Benefit		DG, EE, DR, ES, EV
Project Viability	Qualitative	NA	Developer Experience O&M Experience (Proven Track Record) Commercial Technology Resource Sufficiency Reasonableness of Delivery Date	DG, EE, DR, ES, EV
Creditworthiness	Qualitative	NA		DG, EE, DR, ES, EV

Supplier Diversity	Qualitative	NA		DG, EE, DR, ES, EV
Counterparty concentration	Qualitative	NA		DG, EE, DR, ES, EV
Technology diversity	Qualitative	NA		DG, EE, DR, ES, EV
Conformance to Pro forma terms and conditions	Qualitative	NA		DG, EE, DR, ES, EV
Identified need and overall portfolio position considerations	Qualitative	NA		DG, EE, DR, ES, EV
Site Diversity	Qualitative	NA		DG, EE, DR, ES, EV
Services: Conservation Voltage Reduction	Qualitative	NA		TBD
Services: Reactive Power Support	Qualitative	NA		TBD
Services: Frequency Regulation	Qualitative	NA		TBD
Services: Other Power Quality Services	Qualitative	NA		TBD
Equipment Life Extension	Qualitative	NA		TBD

Illustrative calculations are provided for applying valuation components and determining investment deferral benefit are included below.

Achieving similar performance characteristics as distribution asset
Illustrative example of quantitative and qualitative considerations
Electric Distribution Planning analysis has identified a distribution upgrade due to overload and voltage violations at on XYZ circuit during summer peak condition. An alternative to traditional "wires" solution could be DER portfolio with the operating attributes identified in Table 1.

Table 1: Operating Attributes

Distribution capacity need	3 MW
Voltage support service need	0.7 MVAR
Months when needed	Aug – Sep
Time when needed	13:00 - 20:00
Duration	4 hours
Location	60% in area A and 40% in area B of XYZ circuit

For the determination of optimal DER portfolio, the illustrative evaluation steps consist of

1. First, the valuation using quantitative factors is performed to get the least cost bids.
2. Next, the parameters of DERs portfolio requirement like location, timing, and voltage support capacity are set as selection constraint in optimization. The optimization model selects the bids that satisfy the constraints at least cost.
3. If a DER provides other power quality services beyond what is being procured through the solicitation like Conservation Voltage Reduction, the further review is done. It is assessed how much incremental cost is being incurred for the additional service and determined if that DER provides better value for the customers.
4. In addition, other qualitative factors are considered such as project viability, counterparty concentration etc. when reviewing several portfolios.

Illustrative calculation of distribution investment deferral benefit

The formula for calculating an investment deferral benefit—for a single period and infinite stream—as used by PG&E is as follows:

$$TD[Proj][y] = \frac{TDCapital[y][inv] * Inflation[inv] * RRScaler[y][inv] * \left(1 - \left(\frac{1 + i[inv]}{1 + r}\right)^{\Delta t}\right)}{(1 + r)^{(y - StartYr)}}$$

The following is an illustrative example of a \$5 million investment that is deferred for ten years. Assume the traditional investment has a thirty year life. The present value of the deferral benefit for a single period is \$2,278,821 and the present value of an infinite steam of such traditional investments is \$3,145,593.

	Single Period	**Infinite Steam**

TD[Proj][y]=	Value of investment deferral project in year y.	$2,278,821	$ 3,145,593
TD[Proj]=	Transmission or distribution project		
[y]=	The year the investment is committed.	2017	
TDCapital[y][inv]=	Capital cost of the investment in year y.	$5,000,000	
[inv]=	The investment deferral project, i.e., the investment is part of the T&D project		
Inflation[inv]=	(1+i[inv])^(y-BaseYear[inv]). Convert investment to nominal dollars in the in-service year.	1.00	
i[inv]=	Inflation rate for the investment, e.g., the general inflation rate.	2.5%	
r=	Discount rate.	7%	
BaseYear[inv]=	Year basis for cost estimate for the investment.	2017	
RRScaler[y][inv]=	Revenue requirement scaling factor to convert direct capital costs to revenue requirement levels.	1.49	
□*t=*	The lifetime of the investment.	10.0	
StartYr=	First year of the economic analysis.	2015	
	formula result within parentheses=	0.3493	
n =	periodicity of investment (for PV of infinite stream) in years		30

The following formula is used to convert the present value of the deferral value of a single period traditional investment into a deferral value for an infinite steam of traditional investments.

Where PV of infinite stream (PV_∞) is defined below; r is the discount rate and i is the inflation rate. The present value should be a beginning of year, if EOY gross-up by (1 + discount rate) to BOY. The present value of an infinite stream for a project is calculated according to the formula:

$$PV_\infty = PV_1 * \left[\frac{1}{1 - \left(\frac{1+i}{1+r} \right)^n} \right]$$

Appendix 4: Oversight

Recommendation for Commission Distributed Energy Resources (DER) Deferral Project Process

The following provides s initial recommendation for the Commission oversight process for the working group's consideration according to steps A through D, where:

A = Distribution planning needs assessment and DER deferral project identification
B = Commission authorization for distribution project sourcing through DERs
C = Solicitation of DERs
D = Commission Review of Solicitation Results

The oversight process adopts the constructs of the DPAG and the IPE proposed through the work of the oversight subgroup through its consensus proposal.

A. Distribution Planning Advisory Group (DPAG)

ORA supports identification of distribution planning projects for distributed energy resources (DER) deferral through a distribution planning advisory group, as discussed in the consensus report above.

B. Commission need determination through Tier 3 Advice Letter or Procurement Plan

The developer of this material supports Commission adoption of a framework distribution deferral projects with a long-term planning horizon through the use of a Tier 3 advice letter and development of a DER procurement plan through additional work to create up-front standards which will streamline procurement and shorten the DER procurement timeline. Based on current discussions through the working group, ORA concurs with the consensus report that a DER procurement plan is not ready for Commission adoption at this time. Therefore, ORA makes no specific recommendations related to the adoption of a DER procurement plan at this time.

They also recommend IOUs submit Tier 3 advice letters for distribution deferral projects identified in the DPAG, either individually or grouped into similar attributes. The Tier 3 advice letter should provide the following as a confidential attachment: (1) the value of the DER deferral project (2) Independent Professional Engineer's (IPE's) approval of the DER deferral value's reasonableness and (3) references to corresponding sections in the IOU's GRC. The

Commission's assessment for deferral value reasonableness will be based, in part, on distribution asset value assessed in IOU's General Rate Case (GRC).

C. Adapted Least-Cost Best-Fit Methodology Valuation

The electric utilities currently employ Least Cost, Best Fit (LCBF) principles in the evaluation process of their existing solicitations such as Renewable Portfolio Standard (RPS), combined heat and power (CHP), SCE's Local Capacity Requirement (LCR), and All Source request for offers (RFO) for resource Adequacy (RA) and energy. In accordance with D.04-12-048, the LCBF methodology takes into account the qualitative and quantitative attributes associated with bids to obtain the best value and most cost effective solutions for the electric customers.

Distribution deferral projects present the Commission with the novel challenge of determining need and authorizing procurement for projects which the Commission already authorized through the General Rate Case (GRC) as a planned distribution grid upgrade project. While bids in traditional solicitations compete solely against other bids in the solicitation, bids in a distribution deferral solicitation must always compete with the traditional wires solution. In order to meet the requirement of Public Utilities Code section 769 to "cost-effectively" integrate DER into the distribution planning process, DER deferral projects should be evaluated under the following two-step process.[15]

The first step to the DER deferral evaluation requires the IOUs to assess the total value of the "wires solution" against the "non-wires alternative" or "DER solution." DER pre-commercial testing, project management, operations and maintenance (O&M) costs of maintaining the DER and other administrative costs are all additional costs IOUs incur due to DER deferral and must be weighed against the total costs of the DER deferral in order to fully evaluate the cost-effectiveness of the distribution deferral project. While the aforementioned costs are traditionally accounted for implicitly within the contract, the valuation must be explicit for purposes of DER deferral valuation as these costs may be significant compared to the cost of the DER bid into the solicitation.

In the second step of the DER deferral evaluation, the IOU quantifies the additional value of the DER. Since certain DER are likely to provide both DER deferral and additional grid services value, the incremental value of the distribution deferral and the additional services value should be calculated separately for each resource, with shared costs prorated against the relative value of the DER deferral and the additional value.

When the value of the solicitation shows that the total DER deferral notional value in step one is cost-effective compared to the total notional value of the wires solution, then IOUs would have

[15] Under P.U. Code § 769 (3), IOUs must "Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources."

confidence that the solicitation portfolio should be proposed versus the wires solution. In the event that the DER deferral value was not cost-effective compared to the wires solution, IOUs could assess whether the total portfolio value of the solution was cost-effective. If the project is neither cost-effective for the DER deferral value nor for the total portfolio value of the solution, then the IOU would proceed with the wires-solution through traditional distribution planning processes.

Additionally, if the bid portfolio contained gas-fired generation resources, IOUs would also calculate the greenhouse gas emissions over the lifetime of the resource. While Public Utilities Code section 769 prohibited gas-fired generation DER from competing in distribution deferral procurements, the Commission's DRP guidance made an exception for gas-fired generation resources which reduced greenhouse gas emissions over the lifetime of the resource. Therefore, the IOUs' valuations must also include the a calculation showing the greenhouse gas emissions over the lifetime of the resource, which may be the total greenhouse gas emissions used across the entire microgrid in the event the gas-fired generation serves as a microgrid backup.

The two-step process is necessary to track cost recovery of the DER deferral investments and avoid double payment of distribution services, first through the GRC and again through the Energy Resources Recovery Account (ERRA). Proper tracking is also necessary to account for the potential that DER deferral projects may not successfully relieve the need for a distribution grid upgrade and have to be recovered through both ERRA and the GRC, particularly in the early stages of distribution deferral implementation. The results from an evaluation will inform selection of Offers with which IOU will enter into negotiations. An evaluation methodology is developed and implemented under the oversight of the Independent Evaluator (IE), and Independent Professional Engineer (IPE), the Procurement Review Group (PRG), and Energy Division (ED) staff.

D. *Commission Approval of Solicitation Results through a Tier 3 Advice Letter or Application*

The party who developed this material recommends Commission approval of DER deferral bids using Tier 3 advice letters According to General Order 96-B, Industry Rule 5.3(4) when DER deferral project bids meet the following requirements:

(1) the distribution deferral value is less than the DER distribution deferral value in step 1 of the Adapted LCBF methodology OR the total value of the distribution deferral is less than the total value of the Adapted LCBF methodology;

(2) The value in step 1 is verified and approved by the IPE;

(3) The total cost of the solicitation is reconciled with costs already authorized in the GRC using the following mechanism: The total cost of the DER deferral project will be credited against the total cost of the revenue requirement of the total solicitation. Since ERRA is an annual cost recovery application, it will be easier to account for the changing

value of DER deferrals through ERRA or the DRAM than adjustment through the GRC forecast.

(4) If any bids include gas-fired generation resources, there must be an affirmative showing that greenhouse gas emissions are reduced over the total life of the resource.[16]

(5) Approval of the solicitation bids does not raise important policy questions brought by parties.

If the above conditions are not met, the party recommends approval through an Application. The party's recommendations are conditioned on the Commission's adoption of the adapted LCBF methodology proposed in section C.

Appendix 5: Application of Pro Forma Contract Changes to Sample Pro Formas

Area	Primary Sections of DG IFOM Pro Forma	Primary Sections of DG BTM Pro Forma	Primary Sections of DR ES Pro Forma
Performance based payment structure during the distribution deferral period for solar resources.	-Exhibit E, Section 1.02 (Product Payment Calculations after Commercial Operation Date) Add new payment/ payment adjustment related to performance during targeted distribution deferral period -Exhibit J (Time of Delivery Periods and product Payment Allocation Factors)	-Section 3.1 (Product Payment Calculations) Add new payment/ payment adjustment related to performance during targeted distribution deferral period -Exhibit C (Time of Delivery Periods and Product Payment Allocation Factors)	-Section 7.2(b) (Delivered Capacity Payment) and Section 7.3(b) (Delivered Energy Payment) Add or modify payment/ payment adjustment related to performance during targeted distribution deferral period
There would be an increase in the number of pre-operational milestones as well as consequences for not meeting these milestones.	-Section 3.06(d) (Failure to Meet the Commercial Operation Deadline) -Section 3.16 (Progress Reporting Toward Meeting Milestone Schedule) -Exhibit G (Seller's Milestone Schedule and Material Permits) -Section 3.06(a) (Development Security Amount) Adjustment to Development Security for deviation from milestone schedule that would not impact on-line date -Section 6.01(b) (Seller Events of Default) Add new Event of Default for deviation from milestone schedule that would impact on-line date	-Section 5.2 (Seller Representations, Warranties and Covenants) New covenant to provide milestone progress reporting based on DG IFOM Pro Forma Section 3.16 of the New milestone schedule -4.1(a) (Delivery Date Security Amount) Adjustment to Delivery Date Security for deviation from milestone schedule that would not impact on-line date -6.1(b) (Seller Events of Default) Add new Event of Default for deviation from milestone schedule that would impact on-line date -Exhibit G (New exhibit identifying milestone schedule based on DG IFOM Pro Forma Exhibit G)	-Section 5.1 (Milestone Schedule) -Exhibit D (Milestone Schedule) -Section 9.2(a) (Credit Requirement after Effective Date) Adjustment to Delivery Date Security for deviation from milestone schedule that would not impact on-line date -Section 11.1 (Seller Events of Default) Add new Event of Default for deviation from milestone schedule that would impact on-line date
Development security in the agreement	-Section 3.06(a) (Development Security Amount)	-Section 4.1(a) (Delivery Date Security Amount)	-Section 9.2(a) (Credit Requirement after Effective Date)

Area	Primary Sections of DG IFOM Pro Forma	Primary Sections of DG BTM Pro Forma	Primary Sections of DR ES Pro Forma
Performance assurance in the agreement	-Section 1.07 (Performance Assurance Amount)	-Section 4.2(a) (Performance Assurance Amount)	-Section 9.2(c) (Credit Requirements during Delivery Period)
The agreement would have to be modified to accommodate the voltage support product	-Section 3.01 (Conveyance of Entire Output, Conveyance of Green Attributes, Capacity Attributes and Resource Adequacy Benefits) -Section 3.31 (New section detailing obligations related to voltage support to be added) -Exhibit A, Definition of "Product" -Exhibit E, Section 1.02 (Product Payment Calculations after Commercial Operation Date) Add new payment/ payment adjustment related to voltage support performance	Not applicable	Not applicable

Appendix 6: Customer Outreach Options

Proposals: The following proposals by member(s) of the sub-team outline the range of discussed possible options. Sub-team member(s) also discussed the viability of combinations of Proposals A, B and C.

Proposal A: Sub-team and WG consensus	Pros	Cons
Proposal A – Based on Demand Response Auction Mechanism (DRAM) and Demand Response Aggregator Managed Portfolio (DR AMP) solicitation model: The IOUs, in the solicitation documents, only provide information regarding the current CPUC approved methods for vendors to access customer information. Note: It is expected in the "needs identification and description" portion of the solicitation documents that the geographic area of the need is specified and at least some additional location specific information is provided regarding the customer composition in the local area and other information regarding the timing, frequency, depth and duration of need, etc. The avenue for bidders to access this location specific information would likely be through IOU RFO software which typically requires a Non-Disclosure Agreement (NDA) be signed before access is granted. The types of data that can be accessed and rules for accessing the data should be clearly stated in the RFO documentation.	Transparent and easy to understand and factor into bids by vendors. Privacy rules have been well litigated and settled; this process is working in the view of the IOUs. Has been recently used in the DRAM solicitations and is consistent with current CPUC rules regarding customer data confidentiality. Other useful views of the customer are available from third party marketing research companies and this data is often presented in bids and informs the marketing plans provided to the IOUs by bidders. Encourages vendors to develop data analytic approaches that do not require utilities to share customer specific information that the CPUC has deemed to be confidential. There is positive RFO/IOU experience with this option. May reduce contract administration costs and limit the risk of contract disputes by limiting the IOU's role in the customer acquisition process.	Could limit the pool of bidders to only those vendors who have developed sophisticated customer acquisition and data analytics platforms.

Proposal B: Sub-team and WG consensus	Pros	Cons
Proposal B – Based on SCE LCR RFO and SCE Preferred Resources Pilot (PRP) solicitation model: *The IOUs to a provide a specified level of general customer awareness support services both during the RFO solicitation period and post-contracting during the vendor's customer acquisition period.* *Note* Information shared by the utilities will be neutral and treat all contracted parties equally so all contracted parties are on equal footing to meet contractual obligation *Examples of services could include:* *1.) Creation and maintenance of a customer facing webpage dedicated to the local DER solicitations.* *2.) Commitment to facilitate local "town hall" meetings in the targeted areas to address customer questions about the local DER solicitations.*	Transparent and easy to understand and factor into bids by vendors. Has been recently used in the SCE LCR and SCE PRP solicitations and is consistent with current CPUC rules regarding customer data confidentiality. Also used at SDG&E: all RFO info is on the SDG&E RFO website, and shared at bidders conferences, with less specific needs described, which are open to the public with registration. Encourages vendors to develop data analytic approaches that do not require utilities to share customer specific information that the CPUC has deemed to be confidential.	Could have additional costs to the IOU associated with it that are passed on to utility customers. Could limit the pool of bidders to only those vendors who have developed sophisticated customer acquisition and data analytics platforms that do not require use of customer specific data the CPUC has deemed to be confidential. There is no hard data on the impacts of town meetings or web information on customer engagement that results in recruitment of customers. In fact, could the IOU involvement have negative impact? Could lead to contract administration disputes. For example a vendor could claim that the IOU's webpage design was inadequate which led to the vendor not being able to meet their obligations, etc. If done in partnership with the IOU, the vendors might be limited to talk only about the project in question or the DERs they recruit for in the short term, which might limit future customer engagement.

Proposal C: Sub-team and WG non-consensus	Pros	Cons
<u>Proposal C –Based on SDG&E Enhanced Community Renewables and PG&E Third Party and Government Partnership EE contracts:</u> The IOUs would include in the solicitation documents **post-contracting** enhanced customer acquisition support services. Services for customer engagement support will vary depending on what the vendor is under contract to do for the IOU, as defined by the IOU, and/or as offered by the vendor in the bid. Examples of services could include: 1.) Use of IOUs corporate logo on vendor marketing materials 2.) List of qualified leads specific to the vendor's technology and/or market segment in the local area. In terms of the Competitive Solicitation Framework the details for the enhanced support options and the criteria and cost for vendors to access these options would best be delivered via one of the planned vendor conferences.	There are well established avenues for IOU data sharing post-contract under NDA, including customer data, current customer enrollment, etc. depending on the services contracted. Could increase the pool of bidders into the RFO to include smaller or more recent entrants who have not developed sophisticated data analytics or customer acquisition platforms.	Has not been tested in a robust competitive solicitation environment as envisioned by the CSFWG. Could have additional costs to the IOU associated with it that are passed on to utility customers or would impact the cost effectiveness of the DER. May discourage vendors from developing advanced data analytics and customer acquisition platforms that do not require utilities to share customer information the CPUC has deemed to be confidential. May lead to difficulty in assessing bids as vendors may want to include being able to access these enhanced services post-contracting as a contingence to their bid.

Appendix 7: Non-IOU LSEs Details

Recommendation 1: CCAs Participating in Competitive Solicitations

Certain contracting and other issues arise which carry a high likelihood for requiring resolution, identified below. (One participant felt these should be addressed in other, related proceedings.) Problematic issues for potential resolution include:

- Customer attrition or migration (switching service between LSEs) effects on the viability of contracted DERs to meet grid needs.
- IOUs' lack of visibility into CCAs' planned programs, resulting in IOUs' lack of detailed projections of growth of load/demand when designing RFOs.
- Potential lack of consistent pro forma contract terms for aggregated DER procurement, whether by a CCA, or third party aggregators (TPAs) forming bids in CCA territories deriving from both LSE types, including any cost differences in contracts.
- Challenges to effective deferral of distribution system needs with non-uniform access to customer marketing and customer load profile and local system data.
- Possible limitations due to CCA Code of Conduct requirements for IOUs to interact with customers or prospective customers in CCA-interested areas to solicit anticipated DER program participation.
- Resource aggregation challenges due to CCA automatic opt-ins at inception.
- Limitations on viability of resource financing due to resource/contracting issues.
- Difficulties/complexities in implementing Integrated Resource Plans in overlapping grid areas, potential for increased reliability problems or stranded costs.
- Potential for customer confusion or dissatisfaction due to varying compensation structures for DER market participation, depending on bid structure to be determined.
- Under-utilization of LSEs' (of both types) inherent marketing power without coordination.