Appendix A

Workpaper Supporting ORA's Proposed

Budget Caps

For

PG&E Demo C-E Projects

Appendix A – Public Redacted

ORA's Recommended Budget for PG&E Demonstration Projects C, D and E

IOU	Demo Project	Demo Project Finding Request	Deferred Capital Cost	GRC/Other Funding	ORA Proposed Budget
PG&E	C	$1.75M Utility + $ DER	[redacted]	[redacted]	[redacted]
PG&E	D	$2.1M Utility+ $ DER	[redacted]	[redacted]	[redacted]
PG&E	E	$4.2M Utility + $ DER	[redacted]	[redacted]	NA

ORA Proposed Demonstration Project Budget = (Non-Procurement Costs + (Deferral Value of Distribution Asset x 1.10 Contingency)) – (Funding from GRC, EPIC or other sources))

Project C Budget Cap = $1.75M + ($[redacted] X 1.10) – $[redacted] = $[redacted]

Project D Budget Cap = $2.1M + ($[redacted] X 1.10) - $[redacted] = [redacted]

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[1] PGE's confidential response to ORA's Data Request 9 Q1. The deferred capital cost shown is for the [redacted]r bank at the Esquon substation [redacted] and replace Bank 2 at the Sycamore Creek substation [redacted] See Attachment 1 to ORA's July 29 Reply Comments.

[redacted]

Project E Budget Cap = ORA opposes this project and does not recommend a budget cap.

Notes:

1. ORA’s recommended budget does not include costs for the proportional costs of DER procurement for value streams other than distribution asset deferral, which PG&E can recover through the Energy Resources Recovery Account (ERRA).
2. In future procurement, the value of non-procurement related costs should also be included in the valuation of DER alternatives in comparison to distribution asset (“Wires-Solution”) project implementation.

Appendix B

Workpaper Supporting ORA's Proposed
Budget Caps
For
SCE Demo C-E Projects

Appendix B – Public Redacted

ORA's Recommended Budget Caps for SCE Demonstration Projects C, D and E

IOU	Demo Project	Demo Project Finding Request	Deferred Capital Cost	GRC/Other Funding	ORA Proposed Budget
SCE	C	$9.3M + potential $ DER	[redacted]	NA	[redacted]
SCE	D	$23.65 M + potential $ DER[2]	NA	$23.65 M (EPIC)	
SCE	E	$10.2M + potential $ DER	NA	NA	NA

ORA Proposed Demonstration Project Budget = (Non-Procurement Costs + (Deferral Value of Distribution Asset x 1.10 Contingency)) – (Funding from GRC, EPIC or ources))

SCE Demo C Budget Cap = $9.3 M + ([redacted] X 1.10) – $0 = [redacted]

SCE Demo D Budget Cap = $23.65 M + ($0 M X 1.10) - $23.6

SCE Demo E Budget Cap = ORA opposes this project and does not recommend a budget cap.

Notes:

1. ORA's recommended budget does not include costs for the proportional costs of DER procurement for value streams other than distribution asset deferral, which PG&E can recover through the Energy Resources Recovery Account (ERRA).
2. In future procurement, the value of non-procurement related costs should also be included in the valuation of DER alternatives in comparison to distribution asset ("Wires-Solution") project implementation.
3. "NA" indicates data is not available.

[1] SCE Confidential response to ORA data request A.15-07-002 ORA-SCE-002-Q1a (Costs related to three 12kV circuits upgrades). Included as Attachment 3 to ORA's July 29 Reply Comments.

[2] SCE estimates that this project will cost $23.65 million, but this will be funded by the EPIC IGP project. SCE indicates that DER procurement may be required, but is unlikely to be needed. See SCE July 22 Opening Comments, pp. 8-9.

Appendix C

Workpaper Supporting ORA's Proposed

Budget Caps

For

SDG&E Demo C-E Projects

Appendix C

ORA's Recommended Budget Caps for SDG&E Demonstration Projects C, D and E Projects

IOU	Demo Project	Demo Project Finding Request	Deferred Capital Cost	GRC/Other Funding	ORA Proposed Budget
SDG&E	C	$6.4M total + $DER	New Feeder at Circuit 470 (No Costs Provided)	NA	TBD
SDG&E	D	$9M Utility + $ DER	NA	NA	NA
SDG&E	E	$500K plus potential microgrid modifications	NA	EPIC engineering $, est $250k	$250K

ORA Proposed Demonstration Project Budget = (Non-Procurement Costs + (Deferral Value of Distribution Asset x 1.10 Contingency)) – (Funding from GRC, EPIC or other sources))

SDG&E Demo C Budget Cap = $6.4M + ($TBD M x 1.10) – $0 = $TBD

SDG&E Demo C Budget Cap = ORA opposes this project and does not recommend a budget cap.

SDG&E Demo C Budget Cap = $500K + ($0 M x 1.10) – $250K = $250K

Notes:

1. ORA's recommended budget does not include costs for the proportional costs of DER procurement for value streams other than distribution asset deferral, which PG&E can recover through the Energy Resources Recovery Account (ERRA).
2. In future procurement, the value of non-procurement related costs should also be included in the valuation of DER alternatives in comparison to distribution asset ("Wires-Solution") project implementation.
3. "NA" indicates that data is not available.

Appendix D

Excerpts from

Competitive Solicitation Framework Working Group

(CSFWG)

Final Report

August 1, 2016

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)

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Dated: **August 1, 2016**

Competitive Solicitation Framework Working Group Final Report

August 1, 2016

Table of Contents

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.

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.

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 E

Straw Proposal for a Procurement Process
ORA Presentation at the
August 4, 2016 Workshop in the
Integrated Distributed Energy Resources (R.14-10-003)
Proceeding

ORA
OFFICE OF RATEPAYER ADVOCATES

ORA Straw Proposal for a Procurement Process

August 4, 2016 Workshop

Integrated Distributed Energy Resources (R.14-10-003)

Presented By: Zita Kline and Dan Buch

August 4, 2016

Steps of Solicitation Mechanism

1. Deferral project identification
2. Commission need authorization
3. Solicitation
4. Commission approval
5. Cost Recovery

Step 1. Deferral Project Identification

- **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.

Step 2. Commission Need Authorization

- **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.

Step 3. Solicitation

- **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.

Step 3. Valuation examples

Equation 1 - Capital Investment Revenue Requirement (RR)

RR_1 = (cost($) x IOU-specific Rate of Return (ROR)($)) + Expenses + Taxes + Depreciation = ~ 3.5 %

Equation 2 - Florio 3.5 % incentive, assumes 3.5% is ~ equivalent to RR_1

RR_2 = (Total cost of DER) *3.5%

	Need Authorization	Bids		Additional Cost - Florio Incentive	Least Cost Best Fit Valuation	LCBF Ranking Least-Cost Best Fit Ranking
Project #	Total Wires Avoided Cost	Other Avoided Cost	Total DER Cost			
A	$10M Cost $ .35M RR_1	None	$6M Cost	$.21M RR_2	$10.35M > $6.21M Cost effective for ratepayers	2
B	$10M Cost $.35M RR_1	$6M Avoided Cost of Energy	$14M Cost	$.49M RR_2	$10.35M > $8.49M Cost effective for ratepayers	3
C	$10M Cost $.35M RR_1	$9M Avoided Cost of Energy	$14M Cost	$.49M RR_2	$10.35M > $5.49M Cost effective for ratepayers	1
D	$10M Cost $.35M RR_1	None	$14M Cost	$.49M RR_2	$10.35M < $14.49M No DER deferral	Not Cost-effective.

Step 4. Commission Approval

- **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.**

Step 5. Cost Recovery

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.

– DRAM to recover difference to recover between benefit (avoided wires) and apportioned DER costs.
– ERRA to recover difference of benefit the avoided generation and apportioned DER costs.
– The method for apportioning costs still need to be determined.
– Requires implementation on a going-forward basis to avoid retroactive ratemaking concerns.

Contact

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Appendix F

DER Procurement Framework (DPF), excerpts
SCE Presentation at the
August 4, 2016 Workshop in the
Integrated Distributed Energy Resources (R.14-10-003)
Proceeding

SOUTHERN CALIFORNIA
EDISON®
An EDISON INTERNATIONAL® Company

Distributed Energy Resources Procurement Framework (DPF)

Proposed Concept

August 4, 2016

Cost Recovery Process

- IOU submits DER transactions for Commission's review of DPF compliance via advice letter filings (every six months)
- DER costs would be recovered through the IOU's base rate adjustment mechanisms, such as SCE's Base Revenue Requirement Balancing Account (BRRBA) and/or Energy Resource Recovery Account (ERRA)
  - If transaction is found out of compliance with DPF, then the IOU has an obligation to justify the transaction's reasonableness
- DER costs will be allocated to customers based on the underlying trigger for the need
  - Cost of DER services to defer distribution upgrades would be allocated to all distribution customers
  - Value of services consumed by bundled customers would be credited towards total cost, and recovered separately from bundled customers

Appendix G

PACIFIC GAS AND ELECTRIC COMPANY
Electric Distribution Resources Plan Application 2015
Application 15-07-006
Data Response

PG&E Data Request No.:	ORA_010-Q01		
PG&E File Name:	EDRP-2015_DR_ORA_010-Q01		
Request Date:	August 15, 2016	Requester DR No.:	010
Date Sent:	August 19, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Satvir Nagra	Requester:	Zita Kline

QUESTION 1

Provide a schematic diagram of the Huron substation which indicates the current configuration, including transformer bank numbers, distribution bus/buses, and attached feeder numbers.

ANSWER 1

The schematic diagram of the Huron substation attached EDRP-2015_DR_ORA_010-Q01Atch01-CONF of this data response is critical energy infrastructure and trade secret information and is being provided under Public Utilities Code Section 583.

PACIFIC GAS AND ELECTRIC COMPANY
Electric Distribution Resources Plan Application 2015
Application 15-07-006
Data Response

PG&E Data Request No.:	ORA_010-Q02		
PG&E File Name:	EDRP-2015_DR_ORA_010-Q02		
Request Date:	August 15, 2016	Requester DR No.:	010
Date Sent:	August 19, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Satvir Nagra	Requester:	Zita Kline

QUESTION 2

Provide a narrative summary and dates of key milestones for upgrades to the Huron substation completed since 2010, and those forecast through 2020.

ANSWER 2

Below are the completed distribution upgrades at Huron Substation, and the projects forecast in PG&E's 2017 GRC application:

2/8/2012 – MWC 10 – Huron 1107 and 1109 12 kV circuit breakers and required bus installed for Wholesale PV Generation Project.

2/8/2012 – MWC 10 – Current transformer summation scheme on Huron Bank #1 Load Tap Changer installed for Wholesale PV Generation Project12/16/2013 – MWC 09 – Install SCADA at Huron Substation

5/28/2014 – MWC 46 – Install temporary 70/12 kV, 16 MVA bank at Huron Substation

3/11/2015 – MWC 46 – Remove temporary 70/12 kV, 16 MVA bank at Huron Substation

12/01/2016 – MWC 59 – Replace Huron Bank #1 EI meter

2019 – MWC 46 – Increase bank capacity at Huron Substation

12/16/2019 – MWC 48 – Replace station battery at Huron Substation

PACIFIC GAS AND ELECTRIC COMPANY
Electric Distribution Resources Plan Application 2015
Application 15-07-006
Data Response

PG&E Data Request No.:	ORA_010-Q03		
PG&E File Name:	EDRP-2015_DR_ORA_010-Q03		
Request Date:	August 15, 2016	Requester DR No.:	010
Date Sent:	August 19, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Satvir Nagra	Requester:	Zita Kline

QUESTION 3

Provide a narrative summary and dates of key milestones for upgrades to the Schindler substation completed since 2010, and those forecast through 2020.

ANSWER 3

Below are the completed and forecast distribution upgrades at Schindler Substation:

5/12/2011 – MWC 10 – Schindler 1107, 1108 and 1109 12 kV circuit breakers and required bus installed for Wholesale PV Generation Project

5/12/2011 – MWC 10 – Current transformer summation scheme on Schindler Bank #2 Load Tap Changer installed for Wholesale PV Generation Project

4/24/2015 – MWC 46 - New Schindler Bank #3 115/12kV, 30 MVA and Schindler 1110, 1111 and 1112 12 kV circuit breakers installed at Schindler Substation

2013 – MWC 59 – Animal Abatement work completed at Schindler Substation

2013 – MWC 59 – Schindler 1116 emergency replacement of switch

PACIFIC GAS AND ELECTRIC COMPANY
Electric Distribution Resources Plan Application 2015
Application 15-07-006
Data Response

PG&E Data Request No.:	ORA_012-Q01		
PG&E File Name:	EDRP-2015_DR_ORA_012-Q01		
Request Date:	August 16, 2016	Requester DR No.:	012
Date Sent:	August 19, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Mark Esguerra	Requester:	Zita Kline

QUESTION 1

What is the key milestone that must be met if PG&E's Demo E project will be able to defer replacement of 12 kV cables to Angel Island? For example, does the new DER and microgrid control need to be online and by summer 2017?

ANSWER 1

The key milestone needed would be the demonstration project being released for operation after construction and acceptance testing phases are completed.

For the first step of the project, PG&E is estimating that the DER and microgrid controller would need to be installed at least 4-6 months prior to microgrid operation to allow for performance testing.

PACIFIC GAS AND ELECTRIC COMPANY
Electric Distribution Resources Plan Application 2015
Application 15-07-006
Data Response

PG&E Data Request No.:	ORA_012-Q03		
PG&E File Name:	EDRP-2015_DR_ORA_012-Q03		
Request Date:	August 16, 2016	Requester DR No.:	012
Date Sent:	August 19, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Mark Esguerra	Requester:	Zita Kline

QUESTION 3

When would PG&E have an estimate of the success of Demo E, and the duration of deferral?

ANSWER 3

The duration of deferral is expected to be a 3 year timeframe. Initial learnings and evaluation could be gained within the first quarter of microgrid operation. As mentioned in PG&E's Revised Track 2 Proposals filing (June 17, 2016), PG&E proposes to host quarterly meetings and reporting to stakeholders on the progress of Demonstration E, where the success of this demo can be estimated.

After the 3 year deferral period, should the microgrid perform reliably, PG&E plans to continue utilizing the microgrid as an alternative to rebuilding the undersea cables currently serving Angel Island.

PACIFIC GAS AND ELECTRIC COMPANY
Electric Distribution Resources Plan Application 2015
Application 15-07-006
Data Response

PG&E Data Request No.:	ORA_012-Q04		
PG&E File Name:	EDRP-2015_DR_ORA_012-Q04		
Request Date:	August 16, 2016	Requester DR No.:	012
Date Sent:	August 19, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Steve Calvert	Requester:	Zita Kline

QUESTION 4

In hearings, PG&E stated that it forecast replacing two distribution cables to Angel Island in its 2014 GRC application.[1]

a. Provide a reference for this forecast.

b. What was the forecast need date in the 2014 GRC?

c. Why were the cables not replaced?

ANSWER 4

a. 2014 GRC, Exhibit (PG&E-4), Chapter 16, page WP 16-11 line 169 and page WP 16-49.

b. The forecasted Operative Date was 12/31/2013.

c. The project was not ready for construction in 2013, pending Environmental reviews. In subsequent years, projects were rescheduled and reprioritized within Underground Asset Management program.

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1 Reporter's Transcript Volume 1, R.14-08-013, August 10, 2016, p. 92, ll. 6-10.

PACIFIC GAS AND ELECTRIC COMPANY
Electric Distribution Resources Plan Application 2015
Application 15-07-006
Data Response

PG&E Data Request No.:	ORA_012-Q05		
PG&E File Name:	EDRP-2015_DR_ORA_012-Q05		
Request Date:	August 16, 2016	Requester DR No.:	012
Date Sent:	August 19, 2016	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:	Mark Esguerra	Requester:	Zita Kline

QUESTION 5

In hearings, PG&E stated that non-renewable generation under the second of its two Demo E project alternatives would be "less than 1 percent."[2] Provide the preliminary estimate supporting the "less than 1 percent" response.

ANSWER 5

The correct preliminary estimate was less than 3 percent. This value is based off of the percentage of the propane generator production (kWh) to the total production from all of the generators in the portfolio. PG&E will clarify this number in its post-hearing comments.

Wind = 482,851 kWh

PV = 104,840 kWh

Propane = 16,334 kWh

$$\frac{Propane}{Propane + Wind + PV} \times 100 = \frac{16{,}334}{16{,}334 + 482{,}851 + 104{,}840} \times 100 = 2.7\%$$

2 Reporter's Transcript Volume 1, R.14-08-013, August 10, 2016, p. 53, ll. 6-13.