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 Demand-Side Resource Programs.	Rulemaking 14-10-003 (Filed October 10, 2014)

CLEAN COALITION COMMENTS ON AMENDED SCOPING MEMO OF ASSIGNED COMMISSIONER AND JOINT RULING WITH ADMINISTRATIVE LAW JUDGE

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I. Introduction

The Amended Scoping Memo is an important step in seeking to align programs, rates, tariffs, and incentives with ratepayer interests, while working towards California's climate and energy goals. The Clean Coalition broadly supports the Amended Scoping Memo and the Commission's continued work on the matter. We appreciate that the Scoping is in alignment with the Joint Motion[1] submitted two years ago by twenty parties including the Clean Coalition; however, further attention is also warranted regarding the evolving utility business environment, appropriate business models to align incentives with ratepayer interest, and other public policy goals.

The Clean Coalition strongly supports California Public Utilities Commission's ("Commission") to develop alternative sourcing mechanisms to meet distribution planning objectives and to use programs, incentives and tariffs to maximize localized benefits with minimum expected costs to ratepayers. In particular, the Clean Coalition urges the CPUC to move to:

- develop tariffs with standard contracts and transparent pricing that recognize the particular character of distributed energy resources ("DER"),
- develop methods and markets that fully recognize the full set of values DER provide, and

[1] Motion of The Natural Resources Defense Council et al, March 23, 2016.

- incorporate consideration of alternative utility business models and compensation methods to free utilities to deliver value by providing services rather than being compensated solely for building and operating physical infrastructure.

The Clean Coalition respectfully submits these comments and responses to Attachment A of the Amended Scoping Memo of Assigned Commissioner and Joint Ruling with Administrative Law Judge ("Amended Scoping Memo") issued February 12, 2018[1] under Rules 6.2, 1.9, and 1.10 of the CPUC Rules of Practice and Procedure. The Clean Coalition is a project of Natural Capitalism Solutions, a 501(c)(3) non-profit. The Clean Coalition's mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise.

II. DESCRIPTION OF THE PARTY

The Clean Coalition is a nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement and interconnection of DER—such as local renewables, advanced inverters, demand response, and energy storage—and we establish market mechanisms that realize the full potential of integrating these solutions. The Clean Coalition also collaborates with utilities and municipalities to create near-term deployment opportunities that prove the technical and financial viability of local renewables and other DER.

III. DISCUSSION

The CPUC should think expansively about how compensation and sourcing methods can facilitate preferred resources.

The Clean Coalition makes three recommendations for the process moving forward. First, the CPUC should hold a workshop for stakeholders to bring forward proposals or concepts to meet the needs outlined in the Amended Scoping Memo. Such a workshop would assist the

Commission by providing both the best thinking of stakeholders and the facts and analysis that would be required to make informed decisions on the implementation of these mechanisms. Second, the CPUC should consider a working group to further evaluate these proposals based on evidence and analysis as developed. Third, this proceeding should include an evaluation of the inherent incentives in the cost of service compensation model for utilities and how alternative models would better incentivize utilities and reward shareholders for achieving social and ratepayer value.

The Clean Coalition supports a coordinated methodological approach toward establishing the value of compensation offered for DER functions and services through a variety of mechanisms.

It should be recognized that different compensation mechanisms are necessary and appropriate for accessing the value of DER resources, because such resources included both behind the meter (BTM) and in front of the meter (IFOM) facilities; owned and controlled by customers, utilities, third parties, and independent aggregators; including both existing facilities and future facilities built in response to the interests of each of these stakeholders; and encompassing the full range of DER technologies, each of which can adjust its operating profile in response to pricing signals reflected in rates, tariffs, contracts, wholesale markets, and other compensation mechanisms.

Because each of these influences the others, it is critical to recognize the interaction and important to utilize a coordinated methodological approach as a foundation. Because the functions and services provided by each technology and market sector are broadly interchangeable, we also strongly recommend that needs, goals, and value be established in a manner agnostic to the specific technology, while fully reflecting the value of the Preferred Resources and Loading Order. Technology specific goals or mandates may then be overlaid on this foundation as called for by legislative, market development, or other policy purposes.

The Locational Net Benefits Assessment (LNBA) methodology, tool, and mapped values currently being implemented statewide through the DRP proceeding, and the associated DER Avoided Cost calculator (DERAC), are intended to provide a common methodological approach toward establishing the value of DER functions and services in relation to forecasted grid needs. While we strongly support continued refinement, these methods and tools represent the state of the art today and the Commission should rely upon the current and future iterations as a foundation for the work of this proceeding, including appropriately reflected uncertainties in all costs and valuation.

The Commission should turn also to developing alternative utility compensation and business models that could be used to facilitate development of cost-effective renewable resources and optimize the use of all the capabilities of each resource in aggregate. In the Order Instituting Rulemaking (OIR) for this proceeding, the CPUC undertook to "explore the current incentive structure for the management and shareholders of the electric and gas utilities to support demand reduction."[2] This objective is squarely in line with the mandate of the Commission "to minimize the cost to society of the reliable energy services that are provided by natural gas and electricity, and to improve the environment and to encourage the diversity of energy sources through improvements in energy efficiency and renewable energy resources."[3] Fundamentally, the primary ratepayer public interest is in the delivery of reliable energy service, not the construction infrastructure, so the compensation to utilities should be for the delivery of service, rather than the construction of infrastructure.

Aligning utility compensation squarely with costs to society is fundamentally important to effectively implementing a cost-efficient energy system. Today, California's Investor Owned Utilities have shown some institutional interest in leading the nation in cutting edge approaches, such as using DER to deliver services cost-effectively[4] or acting as a Distribution System Operator to address duck curve issues and to stabilize the transmission grid by intelligent operation of distribution areas.[5] Unfortunately, our IOUs are constrained by concerns that pursuing these solutions can be difficult to justify to shareholders if there are conflicts between cost effective energy service and shareholder value. Thus, it is critical that the CPUC vigorously explore ways to further align shareholder value with ratepayer and societal value. The Commission took major steps in prior decades by decoupling utility profits from generation and customer consumption but has only just begun to address decoupling of infrastructure investment.

Although the value of pilots is a significant start, the Commission will eventually have to develop more modern compensation models that may prove valuable to ratepayers and utility shareholders alike. The CPUC wisely set a goal of "[d]etermining the value of establishing a shareholder incentive mechanism across all demand-side management resources for any utility-specific programs that result from this proceeding."[6] However, this proceeding should begin the process of developing alternative compensation models beyond the scope of the limited pilots initiated in this proceeding to date.

Therefore, the Clean Coalition also recommends opening the scope of this phase of the proceeding to include concepts of alternative compensation models for utilities to provide IOUs with the flexibility to incorporate pay-for-performance or other compensation models as a core part of their business of delivering cost-effective service.

Lastly, we note the critical role of CCAs and municipal utilities in current and future procurement and customer participation programs, including the sourcing of DER at both the customer (BTM) and wholesale (IFOM) level. The methods and programs developed by the Commission should offer effective models that can be adopted by these jurisdictions and integrated into local and statewide planning, while also learning from the experience of these public entities. DER deployment and operating profiles, and customer net load profiles, have major implications on the Grid Needs Assessments developed in the DRP and TPP, as clearly indicated by the $2.6 Billion capital investment reduction in the 2017-2018 TPP.[2] As grid operators, the IOUs and ISO need to reflect DER's contribution to ratepayers savings in infrastructure and operational costs, and ensure that the procuring agencies and owners of these assets receive credit in their rates and tariffs. Current tariffs fail to accomplish this, with the result that far greater potential savings are not being realized.

IV. Responses to Specific Questions

1. Describe how a tariffed approach could be used to source distributed energy resources on an expedited basis. How would the amount of the tariffed payments be determined to ensure that distributed energy resources alternatives are cost-effective? Would the tariff be available to providers on a first-come, first served basis or should some other selection process be implemented?

A. DER Sourcing must provide cost and contract certainty to keep ratepayer costs down.

The CPUC should definitely develop streamlined and cost-effective tariff-based approaches to procurement. DER projects are typically smaller than central generation projects and often operate with smaller margins, such that the high transaction costs and risks of traditional sourcing methods can dramatically raise prices or eliminate potential bids entirely.

[2] See: http://www.caiso.com/Documents/BoardApproves2017-18TransmissionPlan_CRRRuleChanges.pdf

This means that DER sourcing methods must be fundamentally different than traditional sourcing methods to appropriately reflect these constraints. Consequently, the Legislature has recognized the importance of such standard tariffs and contracts to DER sourcing, requiring Distributed Resources Plans to include "standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives" and "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."

Regardless of the precise mechanism developed, any sourcing method that seeks to source meaningful amounts of DER must provide two things: First, the mechanism must provide contract certainty so that administrative costs are minimized, and providers can plan. Second, the mechanism must provide cost transparency and certainty so that providers can both plan projects and finance them cost-effectively.

Ultimately, the lowest ratepayer cost will be achieved by any mechanism that keeps risk premiums and administrative costs low while paying a price like the market clearing price. Although pure auction mechanisms might deliver a more exact market price, unless the difference between the auction mechanism and a data-based or market responsive price is greater than the impacts of risk premiums and contract uncertainty, a pure auction mechanism will actually cost ratepayers more.

A DER owner or aggregator must amortize their costs against the lowest rate of income they can expect to receive with confidence over the life of the DER. If they can count on a compensation stream over a longer period, they can offer services at a lower rate of compensation. Likewise, if they can count on receiving compensation from multiple value streams, they can divide their costs across all services they will be compensated for, allowing them to accept a lower rate of compensation for each service than would be financially viable otherwise. Predictably receiving value for DER services supports market acceptance of a lower price, to the direct benefit of ratepayers. A long-term tariff rate provides this assurance, reducing both the direct costs of bid preparation and the high risk of bid rejection. This results in either greater market response and supply being offered at the same price achieved through a bidding process, or supply of the same quantity at a lower price.

Therefore, the Clean Coalition strongly recommends the development of tailored market-responsive CLEAN programs to save ratepayer costs by minimizing administrative costs and risk premiums, including both those associated with ability to predictably receive compensation for services offered, and the ability to deploy and interconnect DER to offer these services.

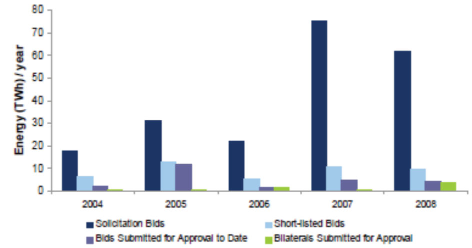
a. Sourcing mechanisms must use standard offer contracts

First, standard offer contracts with minimal bid preparation are critical to successful DER sourcing. Standard offer contracts provide ratepayers with two key benefits. First, by reducing the costs and complexity of bid preparation, standard offer contracts reduce overhead costs that must be made up in the PPA prices. Second, by streamlining the bid process, standard contracts reduce provider risk and thus do not depress the supply of DER proposals or incur risk premiums.

First, non-standard contract auctions incur high bid costs become part of the project cost. Since bid costs under an RFO or other non-standard auction mechanism involve hundreds of thousands of dollars in expenses with high levels of uncertainty around price, providers face bid costs that eat up a high percentage of the project value (A $150,000 bid on a $3 million project represents a 5% cost just to launch a bid for an uncertain price and uncertain contract.) Where these costs are on the order or 5%- 10% of the total cost, the break-even point and thus the minimum PPA price increases by a similar amount.

Second, blind auction, non-standard contracts involve very high risks for developers of receiving no contract, which depresses the supply of potential projects and drives up ratepayer costs. For example, a review of the RPS auction shows that fewer than one in ten bids result in executed projects, while the Renewable Auction Mechanism has recorded an abysmal success rate of 28 executed bids out of 552 bids (see Figure 1 and 2). Similarly, SCE's Preferred Resources Pilot also failed to produce a high number of successful bids. This elevated risk and customization of the proposals reduces the number of bids and increases the price as administrative costs and risk premiums are folded into bids. Furthermore, the process of shortlisting, negotiation, failure, repeated negotiations, offers and then CPUC approval results in unnecessary delays in reaching a higher price and fewer procured resources.

Figure 1 - Fewer than 1 in 10 bids results in an executed contract



Source: California Public Utilities Commission, 2nd Quarter 2009

Figure 2 – RAM has resulted in a high failure rate.

The risks for providers, negotiation failures, and delays in an RFO mean that recruitment will be weaker, and the prices will be higher, and prices will be higher. First, where the risk of success is high, only highly profitable projects will be bid into any auction process, leaving the potential of cheaper projects deterred by the high risk. Second, any investor in any industry charges a risk premium to invest in projects that are more likely to fail. These risk premiums are passed on to the ratepayers. Finally, the lack of certainty makes financing both harder and more expensive for providers, again ultimately driving up the cost of sourcing.

b. Sourcing mechanisms must use a transparent set offer price.

The sourcing mechanism for DER must also use standard, transparent prices. Much like contract uncertainty, price uncertainty ultimate drives up costs for ratepayers for similar reasons. First, where there is uncertainty in the ultimate price, the provider and investors are bearing the risk during project development, which means any bid incorporates a risk premium. Second, uncertainty about the price means that many of the cheapest but marginal projects will not be pursued to the bid stage because of high uncertainty as to profitability. Finally, price uncertainty makes financing more difficult, reducing the supply of offers, just as contract uncertainty does.

c. **Price benefits of auction-style mechanisms must be compared to the magnitude of the risk premium and impacts on bid supply.**

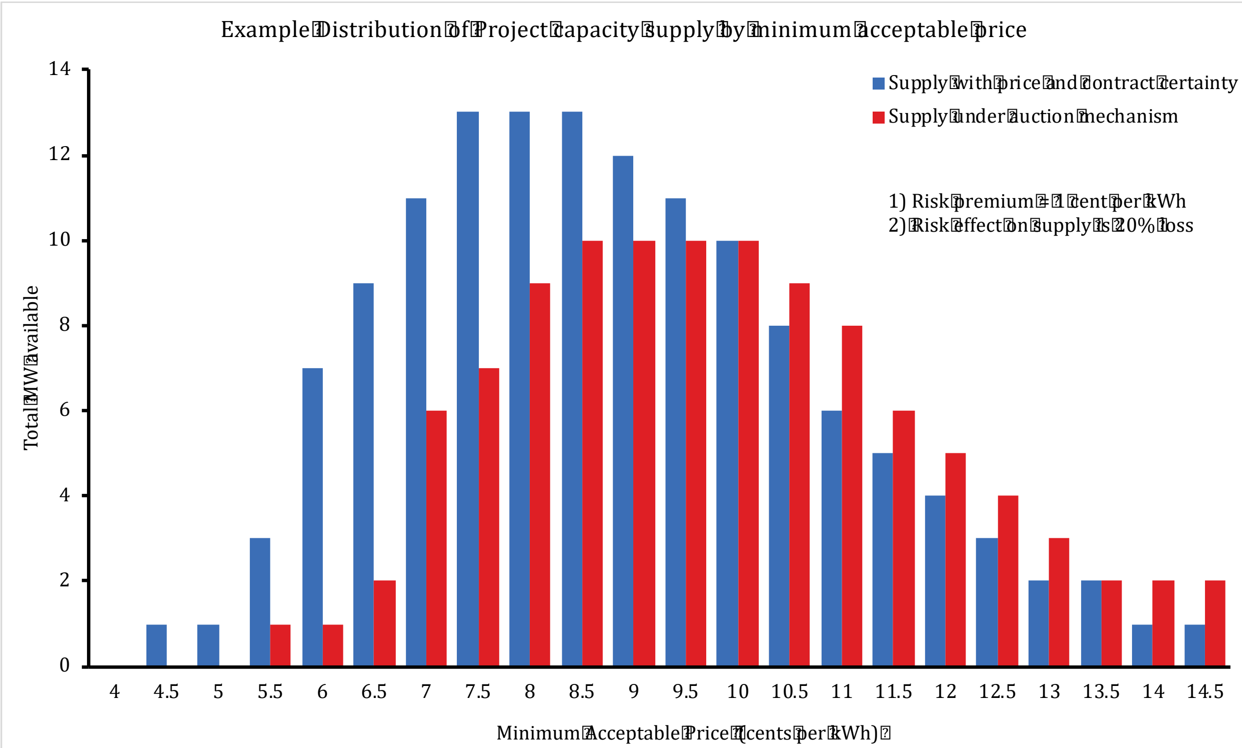
While auction-based mechanisms may be theoretically a more accurate method for determining market price, that accuracy will not translate into any ratepayer benefit if the price benefit of an auction is less than increased costs from risk and decreased supply.

First, the risk premium will be included in any offer or bid and folded into any PPA price. The basics of the business of investment inevitably will make the price for any given supply higher than it would be with a lower provider/investor risk. Thus, the impact of the risk premium would be to increase the price across all projects.

Second, the combination of high transaction costs and uncertainty mean that many projects simply will never be bid in. For example, if the conversion rate of bids into deployed, income producing projects is 10% and the bid costs are $150,000, the expectation would be $1.5 million in total bid costs for every successful project. Thus, any project generating less than $1.5 million in profits for the provider would not be worth developing as a bid, and ratepayers would not have the option of sourcing energy from less profitable projects as they simply would not be sensible to bid into any auction.

When these factors are combined, they can easily swamp any savings from an auction mechanism. For example, in the numerical example below, a range of projects would be available for sourcing based at a range of minimum acceptable prices to allow projects to be minimally profitable, shown in blue. However, in this example investors, providers, or financiers ask a 1 cent per kWh risk premium to cover the increased risks of big failure before bidding. Furthermore, 20% of all bids are deemed unlikely to be successful and are dropped before bids to generate the supply under an auction mechanism, shown in red.

Figure 3 is on the next page.



The sourcing entity would then use one of two approaches to sourcing, for example 70MW: a standard offer contract, fixed transparent price Feed-in tariff based on a market-adjusting mechanism, which alleviates the risk premium and bid loss, or a standard auction with the risk premium and bid loss.

In this example, a market-responsive Feed-in tariff would procure the 70 MW by offering 10.5 cents to all projects at that price or lower, for an average PPA price of 10.5 cents. In contrast, the auction mechanism would pay the minimum bid price to all projects until the 70 MW are sourced. However, in this case, the average bid price would be 10.6 cents/kWh because the risk premium and bid loss effects are big enough to offset the illusory savings from paying as low as 5.5 cents/kWh for the best performing projects.

A well-designed market -responsive feed-in tariff is likely to deliver a fix offer price that would be very similar to any auction price, but because of the risk and supply effects, would be likely to deliver lower overall ratepayer costs. Of course, how the risk premium and bid costs trade off against any differential between the fixed-price and the blind auction price is an empirical question. However, the benefits of standard offer contracts and transparent pricing are unequivocal and must be considered in evaluating any tariff or other sourcing mechanism.

d. Standard offer-transparent set-price mechanisms can easily incorporate locational pricing

These methods can also be used to incorporate transparent locational pricing provided the locational values by treating locational value as an adder. In such a system, a transparent price system could offer a standard price with an increment to incentivize placing projects as particular locations. In fact, theoretically, adders could also be used to incentivize availability at particular times of day or for dispatchability (which would mostly allow energy storage projects to monetize the value they provide to the grid.).

e. Alternative sourcing methods must provide for market for a full range of DER services

Effective DER sourcing must capture the full value of the services that DER provide. Cost-effective DER sourcing requires robust supply of bids, and that can be maximized by providing viable revenue streams for project development. Thus, ratepayer costs are likely to be best constrained by providing for multiple revenue streams with minimal administrative costs. Ideally, the mechanism should incorporate a single market or procurement contract that allows optimal dispatch and allocation for both meeting grid needs, utilizing available resources, and stacking compensation. This allows each resource to be more fully utilized, spreading cost recovery across multiple value streams, and thereby allowing each service or function to be offered at lower cost.

f. Sourcing mechanism should be technology neutral and focused on the services required rather than the technology deployed.

Sourcing mechanisms should define the sourcing in terms of the electrical need or service required and allow DER providers to develop approaches to cost-effectively meet the electrical need. Given that many DER can combine to provide a wide range of services in aggregate, it is critical that the DER provider have the flexibility to assemble a suite of DER to provide a particular need, rather than specifying the technology. The relative costs of Demand Response, Storage, generation and efficiency can vary depending on site and customer, so the sourcing mechanism should allow ratepayers to benefit from the ability of DER providers to assemble the lowest cost suite of resources for any given need.

Furthermore, the sourcing mechanism should evaluate projects based on projects, rather than limiting access to a smaller pool of applicants or providers. Just as bid-loss from risk and uncertainty drives up ratepayer costs, so would placing limits on DER providers through a pre-qualification process. Such a process may assist or streamline assessment of individual projects as qualifying but shouldn't act as an outright bar to participation. (That is, when bids are evaluated for whether they meet offer criteria, pre-qualification may be used to streamline the evaluation process.)

g. Sourcing should come from first-come-first served, market-based mechanism

One well-established mechanism that has a proven record of successful, cost-effective procurement is a CLEAN program: a market-responsive, set-price Feed-In Tariff. The CPUC has previously approved a modestly successful market-responsive, set-price tariff program in ReMAT. Although ReMAT has implementation issues in the queueing process and the process for adjusting prices, it has proven to be a major improvement on traditional Feed-In Tariffs. With the addition of locational benefit adders, dispatchability adders, or time dependent pricing, CLEAN programs can deliver DER at market-defined prices without the high administrative and risk costs of an auction.

The pricing mechanism in a CLEAN program involves the offer of tranches of the total amount to be sourced with the prices determined by the response to the prior round. The initial price should be set well below the expected market price to ensure cost-effective pricing and incorporate first-come, first served bid uptake. The procedure would run as follows:

1) Offer standardized, transparent, non-negotiable contracts, with streamlined interconnection processes, including batch studies.
2) Establish initial price for first tranche of capacity via market research or by reverse Japanese Auction, in which all bidders enter the auction for the first round at a high offer price and then drop out as the auction price is lowered until only enough bids to fill the tranche remains.
3) Adjust price at each successive tranche at price depending on market response to prior round (upward if response is weak, downward if strong)
4) Continue until the entire procurement is filled.

Market-responsive adjusting tariff programs deliver a theoretically better or comparable price to a standard auction. First, as noted above, the prices do not include risk premiums or price increases due to bid loss. Second, using a sequential round of tranches delivers a proxy price that would be lower than a single auction with a market-clearing price. Third, by breaking up the full procurement into tranches, the full procurement delivers a similar range of prices from cheapest to most expensive as would be achieved through a blind auction. Theoretically, a standard RFO-style auction results in every project having an individualized contract price, while a market-responsive adjusting tariff program results in groups of similarly priced projects sharing an identical price. However, projects are facing similar costs and constraints, which means that the projects in each tranche would be similarly priced under either mechanism. Since projects will participate only in tranches at or above their minimum acceptable price, the overall distribution of prices in a market-adjusting tariff is a close proxy for the distribution of acceptable prices, but without the markup for risk or bid loss that reduces competition.

g. Sourcing should come from first-come-first served basis

A first-come, first-served process is best for delivering the savings from giving price and contract certainty to providers. A major benefit of the CLEAN program are the savings that result from reducing risk and providing business certainty. Thus, to maximize that certainty, projects should be taken on a transparent first-come, first-served basis so that providers can plan on some level of contract certainty. Mechanisms that create uncertainty drive up the costs to ratepayers.

Question 2. *Could a streamlined version of the competitive solicitation framework used for the Incentive Pilot projects—such as a request for bids process—be a viable alternative, where distribution services are standardized? Describe in detail the steps involved in a streamlined competitive process.*

Yes. Streamlined procedures based on the CSF framework subject to the above principles of contract certainty and price certainty would be critical for sourcing standardized distribution services. Essentially, the market-responsive, set-price CLEAN program represents a streamlined CSF framework with the critical components to reduce administrative costs and bid-loss costs.

The key factor remains first come, first served contract acceptance, as may be seen in an ongoing reverse auction process in which a low price is offered, and qualified responses are assured of contract at that known price, with the price being raised over time to attract additional responses until the desired quantity is achieved.

We note that this approach is problematic where a minimum quantity of contracted DER is required to realize an infrastructure deferral value. As such, development of generation, load reduction, or other services should first be pursued and compensated based on the value of these resources adjusted for the probability of their contribution to infrastructure deferral. In many, even most cases, this will result in DER deployment and operational profiles that mitigate grid impacts and prevent grid stresses from developing such that the need for upgrades is indefinitely deferred and the scoping of specific grid investment projects is avoided. Where these value streams have not resulted in the desired level of DER services, then a targeted RFO may be appropriate in which the full value of the deferral is used to cap the value of offers, and contracts are contingent upon adequate total capacity being contracted. Such RFOs should aim to be standardized and the barriers to participation lowered to ensure adequate market response and competition. Reducing barriers to participation must not be confused with unduly lowering qualifications needed to ensure offers are <u>reasonably</u> likely to fulfill the contract; rather, the goal is to reduce the costs and other barriers associated with participation by qualified bidders.

Question 3. *Should the Commission establish separate rules and requirements for a streamlined version of the competitive solicitation framework?*

Yes. (See response to Question 2 above) The solicitation framework still appears to rely upon an opaque auction mechanism that drives up administrative costs and uncertainty for providers. Under the current state of the market and the smaller nature of the DER sector, these factors are severely inhibiting the development of California's DER sector relative to other states and countries that have deployed standard-contract, set-price programs. It does not appear that the rules and requirements for the CSF successfully reduce the transactions costs to support a robust DER sector to provide the solutions to grid needs.

We note that a market responsive pricing mechanism incorporated in a Standard Offer or Feed-in Tariff should be considered to categorize these as competitive solicitation processes. In this instance, the market competes on a first come-first served basis to accept the capacity available through a below-market rate standard offer, and the rate offered increases to attract greater market response as needed. The Commission has already approved and employed the Renewable Market Adjusting Tariff (ReMAT) with some success, although it included participation qualifications that conflicted with Rule 21 timeline requirements and extended procurement schedules that severely hampered program viability.

Question 4. *Are there other mechanisms the Commission should consider in order to deploy cost-effective distributed energy resources that satisfy distribution* *planning requirements as required by Public Utilities Code § 769(b)(2)? Describe these other mechanisms in detail, including proposed necessary steps?*

Yes. Please see Question 1 above.

Question 5. *What additional information does a distributed energy resources provider need to know to participate in each of the mechanisms proposed in the response to the questions above? What additional information should the utilities make available to the distributed energy resources providers to create the right market signal?*

As described above, it is critical to make the technical requirements, contract terms and price transparent to DER providers. In addition, providers will need clarity regarding the interconnection processes and capabilities for whichever sites providers are considering for the development of DER. When these requirements are transparent and all projects meeting the requirements receive contracts up to the full allocation of a given tranche, providers will be in the best position to provide the largest number of lowest-cost bids to ensure cost-effective DER sourcing.

As noted above, a supplier can offer the lowest price if they have certainty regarding compensation for all the services they can provide. In this regard, an integrated market or contracts covering the full suite of services will avoid the problems associated with disaggregated markets and contract priority between services. For example, a DER may be able to offer energy, demand response, flexible capacity, resource adequacy, distribution investment deferral, voltage support, and frequency services. Ratepayers will receive the greatest value if the DER dispatch is optimized for the highest localized value at any moment, but this is not possible if the DER is independently contracted for each service.

Utilities need to provide three key components for market signals: a known cost of interconnection, a guaranteed minimum or set price that providers can use as a basis for financing and planning, and a known premium or adder reflecting localized net benefits.

Question 6. *Should expedited procurement processes only be available to certain categories of distribution services? Should they only be available to deferral opportunities below a certain threshold of deferral value (e.g., single products or cluster of projects for which the traditional investment* *would cost $10 million or less)? Explain why the response would differ depending on the specific type of expedited procurement process.*

Not necessarily. For the reasons stated above, expedited and especially transparent procurement processes reduce ratepayer costs overall. Thus, the key question is whether there are categories of distribution services that warrant higher transaction costs. Generally, a standard-contract, set-price mechanism will deliver cost-effective DER services regardless of the service needed. Theoretically, there might be a need for additional information or review for particularly large projects, but since even large needs (e.g., meeting the 308 MW LCR in the Moorpark subarea) would be met with a relatively large number of smaller DER projects, the impacts of any single DER project is likely to be small. If anything, the limitation should not be based on the total size of the need, but rather on the size of the DER project and its effect on the grid, rather than using a cost-cutoff.

As noted in our response to Question 2, rates, tariffs, programs, and other compensation mechanisms should be fully employed and locationally targeted first at prices lower than dedicated procurement costs, regardless of the size of the need. As also noted above, DER has greatly contributed to $2.6 Billion in avoided transmission infrastructure investment between 2016 and 2017 TPP planning cycles. IDER incentive and compensation mechanisms are very well suited to broad application for large quantities of DER within a distribution or transmission planning area rather than just individual distribution infrastructure deferral on a single circuit.

Question *7. For each of the mechanisms proposed in response to the questions above, describe the approval process the Commission should adopt.*

Since the standard-contract, set-price mechanisms involve a program rather than individualized authorizations, the key approval role of the Commission would be to approve the final standard offer contract after input from potential providers and for the procedure for accepting bids into the tariff-based process. Once the price-setting mechanisms, interconnection processes, and standard offer contract are established, there would only remain an oversight role for the Commission to ensure that the procurement proceeded as planned. This role could be fulfilled by advice letter with potential for a reopening should the program fail to perform as desired.

Question *8. Explain whether the Commission should focus on the development of one* *mechanism or an assortment of optional mechanisms for providers.*

DER and DER providers potentially take a wide variety of forms, from single large C&I Demand Response Customers, to aggregated DR programs, to wholesale distributed solar + storage providers. Given that the

***Question** 9. What existing Commission-approved programs, incentives, and tariffs would benefit from a coordination plan, as required by Public Utilities Code § 769(b)(3), and result in maximum locational benefits and minimal incremental costs? Similarly, should the Commission consider coordination with the Interconnection Rulemaking (R.17-07-007) to ensure operational requirements of Smart Inverters are aligned with any relevant valuation mechanism?*

All programs aimed at procuring DER to provide grid services should be coordinated to enable projects to realize the full set of revenue streams reflecting the benefits DER provide. As noted in Question 1, allowing the monetization of a large number of streams reduces the cost of procuring resources to provide any particular service. Thus, an integrated program allowing DER to provide as many services as possible, ideally through a single market or mechanism would both reduce overall ratepayer costs and maximize both locational benefits and other benefits as DER can provide.

Yes. Ultimately, the Commission should develop the operational requirements to support the provision of the full suite of DER services and for DER providers to capture the full value of those streams. Consequently, it is critical to have the potential financial values of DER supported by the technical capabilities of DER without requiring services without compensation. In addition, the streamlined interconnection process is fundamentally important to enable ratepayers to realize the full benefits of DER. By making DER deployment easy, ratepayers will benefit from increased competition and supply of DER resources.

***Question 10.** Other than maximizing locational benefits and minimizing incremental costs pursuant to § 769(b)(3), are there other objectives the Commission should consider when developing the required coordination plan?*

Yes. Providing cost-effective locational benefits is supported when the DER meeting particular locational needs also have other elements of the revenue stack available to defray the costs of a particular DER deployment. Thus, the Commission should endeavor to develop a single, transparent, and streamlined mechanism for DER to provide multiple services and applications.

Question *11. What steps could the Commission adopt to coordinate these existing programs, incentives, and tariffs and/or other proceedings to maximize locational benefits and minimize incremental costs? Are there procedural steps that need to be taken to implement this coordination?*

The first step would be to compile information for all pilots, incentives, and opportunities that the Commission has authorized or that utilities have engaged in. A single resource outlining the full set of pilots, programs, and incentives would enable a better-informed design for a coordination plan, both within utilities and across utility efforts.

Given a comprehensive overview of the existing programs, incentives, and tariffs, a working group of utility, environmental, ratepayer, and provider advocates would be in a position to work with the commission to develop streamlined approaches to enable DER to participate and coordinate the various lessons learned and to leverage the existing vehicles to produce a single coordinated process for DER to participate in multiple processes and programs to foster grid and ratepayer benefits.

Question *12. Given that the Locational Net Benefits Analysis Cost-Effectiveness Use-Case and Methodology is still in development in R.14-08-013, should working this proceeding to implement Public Utilities Code § 769(b)(3) begin in parallel or should work wait for completion of the Use-Case?*

This proceeding should not delay work integrating the Locational Net Benefits Analysis Cost-Effectiveness Use-Case and Methodology, and should work in parallel with DRP and future refinements in the LNBA.

While we strongly support continued refinement, these methods and tools represent the state of the art today, and the Commission should rely upon the current and future iterations as a foundation for the work of this proceeding, including appropriately reflected uncertainties in all costs and valuation. DERAC is already used in cost effectiveness evaluation, and LNBA is a major enhancement to this tool. Failure to use the most accurate information available is unacceptable for ratepayers. Clearly reliance upon an imperfect value is better than reliance upon a value known to be less accurate.

DRP guidance[3] instructed the IOUs to develop a unified locational net benefits methodology consistent across all three IOUs based on the DERAC, enhanced to explicitly include location-specific values in order to specify the net benefit that DERs can provide in a given location. Further guidance proposed[4] consideration of a process whereby location-specific, distribution-level avoided costs developed in the DRP would be paired with non-location-specific or system-level values in the IDER cost-effectiveness framework. Such guidance was reinforced by a staff proposal in the IDER proceeding that, as a part of a four-part process to improve the cost-effectiveness framework, recommended "Phase 2: in coordination with the Distribution Resources Planning (DRP) proceeding (R.14-08-013), improve the relationship between cost-effectiveness and actual system conditions."[5] In sum, the Commission has intended the LNBA to link existing programs and cost-effective tariffs to actual conditions across different locations on the distribution system.

Following these initial directives, the Commission has gone on to define broader uses for the LNBA in related proceedings. First, D.16-01-044, deferred substantial changes to NEM incentive levels until 2019, when the LNBA would be sufficiently developed to estimate the locational value of DERs.[6] The presumption is that the next regime of NEM incentives would be tailored to the relative costs and benefits of DER deployment at given locations on the grid. Furthermore, the Integrated Resource Planning (R.16-02-007) effort initiated by Senate Bill 350 seeks to develop supply curves for DERs based on distribution system costs and benefits in order to determine optimal resource portfolios to meet state greenhouse gas and resource procurement mandates.[7] DRP Demonstration Project B guidance directed the IOUs to develop a comprehensive quantification of DER value at any location on the distribution grid for IDER sourcing and cost effectiveness evaluations.

Given the Commission's statements on these matters, the Commission affirmed in D.17-09-026 that a third use case for LNBA is to develop a comprehensive quantification of DER value at any location on the distribution grid for IDER sourcing and cost-effectiveness evaluations, informing DER incentive levels, providing distribution-level costs and benefits

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[3] *Guidance Ruling, Attachment 4*

[4] DRP Roadmap Staff Proposal, November 16, 2015, at 18-20.

[5] *IDSM Cost-Effectiveness Mapping Project Report and Staff Proposal* at 8

[6] D.16-01-044 at 20-22, 60-61.

[7] *Administrative Law Judge's Ruling Seeking Comment on Staff Proposal on Process for Integrated Resource Planning*, May 16, 2017, at 46-47

information to IRP, and other potential related applications. The LNBA is intended to be able to flexibly calculate net benefits at the distribution system granularity and value aggregation method required by the particular application (e.g., portfolio, program, tariff, or contract) being evaluated. Under Commission order the IOUs have already filed proposals for modeling and methodological approaches that enable LNBA to calculate DPA-level avoided T&D values for input into DERAC, with development to coincide with the 2018 distribution planning process.

IDER can and should proceed to develop and integrate the range of compensation mechanisms required to optimally incent DER development. The valuation and pricing for such compensation should be formula based. This will allow for LNBA and other value inputs to be reflected in the formula, and for these values to be updated as they become available. As such, it is incumbent upon this proceeding to have these formulae and compensation mechanism under development without delay and ready to accept updated values.

IV. CONCLUSION

The Clean Coalition appreciates this opportunity to provide comments and supports the Commission's continued work in IDER.

Respectfully submitted,
_____/s/____
Doug Karpa
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Clean Coalition

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