BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures, and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking R.14-08-013

COMMENTS OF THE GREEN POWER INSTITUTE ON THE OIR

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Gregory Morris, Director
Tam Hunt, Consulting Attorney
The Green Power Institute
a program of the Pacific Institute
2039 Shattuck Ave., Suite 402
Berkeley, CA 94704
ph: (510) 644-2700
fax: (510) 644-1117
gmorris@emf.net

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Pursuant to the August 20, 2014, *Order Instituting Rulemaking*, in Proceeding R-14-08-*013, the Order Instituting Rulemaking Regarding Policies, Procedures and Rules for* **Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769**, the Green Power Institute (GPI), the renewable energy program of the Pacific Institute for Studies in Development, Environment, and Security, provides these *Comments of the Green Power Institute on the OIR*. In these Comments we address the questions posed in the OIR.

1) What specific criteria should the Commission consider to guide the IOUs' development of DRPs, including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources, and enables the achievement of California's energy and climate goals?

Electric-distribution systems in California have been designed with the understanding that the flow of energy will be strictly one-way, originating at the point or points of connection to the transmission system, and flowing through the distribution system to the many points of consumer use. The wide-scale deployment of DR systems, especially distributed renewable generating resources that feed power into the grid, requires a major change in this paradigm. Widespread deployment of DR means that not only will power flow in both directions at various times within a distribution segment, but there may be periods of surplus energy during which power needs to be moved from the distribution system into the transmission system.

In order to accommodate DERs, major changes will need to be made to the state's existing distribution systems. In particular the distribution systems' entire protective infrastructure will have to be upgraded to cover two-way flows, and in some cases higher capacity wires may be needed. In our opinion the primary criterion that should guide the development of the DRPs is the directive to make preparations within each segment of the system for two-way flows within distribution circuits, and for two way exchanges between distribution segments and the integrated electricity grid.

Cost-effectiveness should be a key criterion for upgrades identified in the DRPs. By identifying the most likely areas for significant DER build-out (including generation, storage, and PEVs), and investing in distribution upgrades accordingly, ratepayers will benefit from advanced and coordinated action. While ratepayers still enjoy a temporary waiver from allowance limits for EV-prompted circuit upgrades (pursuant to D.13-06-014), this waiver won't last in perpetuity. Rather, IOUs should identify areas where PEVs are expected to be adopted in high numbers and build out the distribution grid accordingly in advance of such adoption. This is a more efficient means of grid upgrades than one-offs prompted by individual customers, because such upgrades can be coordinated and aggregated.

Similarly, IOUs should proactively identify areas that are likely to see significant distribution-interconnected DER (wholesale or retail), and invest in grid upgrades required to accommodate such two-way flow of power in a coordinated manner. This will also save ratepayers money.

In terms of valuing locational benefits, as required by AB 327, the IOUs and the Commission should draw upon previous Commission work. Specifically, the E3 report commissioned in 2011 by the Commission should be used as a starting point for this new analysis. This report was part of the SB 32 implementation process in R.11-05-005.

Lastly, no greenhouse gas emissions analysis should be required in relation to the development of the DRPs as long as the resources considered in the DRPs are the §769-eligible technologies: renewable energy, demand response, storage, CHP and PEVs. This is the case because all of these technologies have unequivocally beneficial impacts on GHG emissions, so no higher-level analysis is required.

2) What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?

The legislation is clear about what elements are required in a DRP. Section 769 provides four bullet points that must be satisfied. First, the DRP must evaluate the locational benefits of DER in various segments of the IOU's distribution system. Second, the plan must present mechanisms, such as tariffs or incentives, which encourage the deployment of DER consistent with the DRP. Third, the plan must coordinate among existing programs and proceedings related to DER deployment. Fourth, the plans need to identify utility investments that are needed in order to accommodate, in a cost-effective manner, anticipated DER additions of various kinds to the grid.

In the opinion of the GPI the fourth element listed above, the identification of needed utility investments in order to accommodate anticipated DER additions, is the key conclusion that the DRPs are designed to produce. Most of the future DER additions to the distribution grid will be provided by non-utility entities. The purpose of the DRPs is to anticipate what kinds of technologies and installations the non-utility sector will develop, and to guide the utilities to make the investments necessary to accommodate and facilitate the anticipated DER build-out.

We also note that the second element above includes development of standard tariffs. GPI supports the development of additional procurement mechanisms based on standard tariffs, in order to accelerate the development of DER. For example, the SB 32 Renewable Energy Market Adjusting Tariff is a relatively small program that evolved from the previous AB 1969 feed-in tariff. The SB 32 program should be expanded, and GPI encourages the IOUs and the Commission to create a robust and cost-effective feed-in tariff program to spur development across the DER spectrum.

3) What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?

The calculation methodology for determining optimal locations of DERs should take the following criteria into consideration:

- Whether a distribution segment needs upgrading in the absence of DER additions, and whether the addition of DER can cancel or reduce the cost of the needed upgrades.
- The likelihood that future demand growth on the circuit, e.g. for the charging of plug-in electric vehicles (PEV), or simply due to the addition of new points of use (new consumers), will necessitate new upgrades, and whether DER installations can avoid the need for conventional distribution-system upgrades.
- Whether the addition of DERs on a distribution segment will necessitate upgrades of the system in order to accommodate the additional DERs.
- Whether the addition of DERs on a distribution segment will change the cost of operating the segment.

4) What specific values should be considered in the development of a locational value of DER calculus? What is optimal means of compensating DERs for this value?

The development of a "locational value of DER calculus" is extremely complex, and probably will require the use of sophisticated system modeling. There has been a good deal of work performed in this area, and we urge the Commission and the IOUs to base their efforts on existing work. If and when optimal locations for DER are identified, the question is what kinds of incentives might be appropriate for motivating developers to locate their projects in these locations. In the opinion of the GPI, the most promising type of incentive for steering DER installations towards specific locations would be to reduce their interconnection costs, for example by having the IOUs use generic studies, or waive the cost of specific interconnection studies for installations at identified locations. We do not think that there should be alternative tariffs available based on locational factors, but we would like to see locational values built into standard tariffs. Well-located DER can provide substantial and quantifiable benefits to the grid and these benefits should be compensated or, at the least, form the basis for real incentives for DER developers.

5) What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?

State policy in California favors the deployment of all of the kinds of DERs that are §769-eligible. Each DRP should be based on the expectation of increased DER deployment in all segments of their systems. The planning scenarios should prepare for increased proportions of energy injection around their distribution grids, for increased loads due to the proliferation of electric vehicles, and for increased use of smart-grid technologies and DER technologies like storage to provide a range of operating services to the distribution grid. The DRPs need to not only envision obtaining grid-operating services from DERs, they also need to make provisions for how to accomplish this.

7) What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?

The benefits that should be considered in quantifying the value of DER additions to a distribution-system segment include the deferral or avoidance of conventional distribution infrastructure, the accommodation of increased load on various distribution segments, the avoidance of local fossil-fired generation, and increased grid reliability.

8) What criteria and inputs should be considered in the development of scenarios and/or guidelines to test the specific DER integration strategies proposed in the DRPs?

One of the mandated activities that the legislation requires of the DRPs is that they will identify optimal locations for the deployment of DER in various distribution circuits. However, it is important to keep in mind that the actual build-out of DER is likely to be different than the projected optimal configuration, due to the fact that many of the developers will be working with considerations and factors that are less than optimal, from a distribution-system perspective, but are very relevant to their own individual circumstances.

In order to be able to accommodate a range of possible future DER configurations, it will be necessary to construct a representative set of scenarios for consideration in the DRPs. The base-case scenario should be the identified optimal DER scenario that is a mandated component of the DRPs. An important criterion for constructing additional scenarios is that the alternative scenarios should present significantly different DR configurations than the configuration in the base-case scenario. This can include different spatial configurations, different mixes of technologies, and varying sizes of DER installations at various locations. In the opinion of the GPI, three to five scenarios should be adequate to support a comprehensive DRP.

9) What types of data and level of data access should be considered as part of the DRP?

There is a natural tension between the transmission utilities and all other parties over access to information on transmission-system operations, and the operations of existing DERs on the transmission system today. Nearly a decade ago, in R.05-06-040, the Commission engaged in a painstaking process to establish rules for access to RPS data, which by state policy were entitled to greater access than other kinds of utility data.

In the opinion of the GPI, there should also be greater access to operational data regarding distribution grids than there is for other kinds of utility data, equivalent to the situation for RPS data. Access to data comes in two categories, unrestricted, and restricted to parties that agree to confidentiality terms. As a basic philosophy, we believe in making as much data as possible accessible in the public domain. For categories of data that truly are deserving of confidential handling, the confidentiality terms in non-disclosure agreements should avoid being onerous as much as possible.

10) Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?

An emerging DER that might very well benefit from demonstration projects or measures in the DPRs is the smart charging of plug-in electric vehicles, particularly in commercial charging applications. Until recently most analysts believed that the greatest value that PEVs can provide to distribution systems would be to flatten the demand curve by providing a new load that would be served primarily overnight. However, with the widespread deployment of solar-energy systems around the state, it now appears likely that the greatest contribution that PEVs can make to the grid is by midday charging, for example by charging in commercial charging stations located near the workplace. Midday charging can absorb the increasing surplus of solar power available in California during peak periods when the sun is strongest, and demand is well below peak. Moreover, because many of the PEVs in these kinds of charging stations can be plugged in for a longer period of time than it takes to charge them, it should be possible for commercial charging enterprises to provide operating services to the grid by coordinating the charging load with grid needs so that in periods when there is surplus energy in a distribution circuit maximum charging load is applied, and when there is a deficit of energy on the distribution segment charging can be reduced or cutoff. This can be effectuated in real time automatically via smart-charging technologies.

From the perspective of the integrated electricity grid PEVs are, in effect, mobile storage devices. Another §769-eligible DER technology is storage, which, like PEVs, is a currently emerging technology. In R.10-12-007 the Commission has promulgated a series of targets for installations of storage systems for the three large IOUs. In the opinion of the GPI the DRPs should consider offering demonstration projects or other measures for conditioning the market for fixed-storage installations.

The utilities have already accumulated a good deal of operating experience integrating rooftop and larger PV generators (e.g. up to 50 MW installations) into distribution-system grids. Since these systems tend to be operated in a passive mode, we do not believe that demonstration measures or projects for PV installations are needed in the DRPs.

11) What considerations should the Commission take into account when defining how the DRPs should be monitored over time?

Section 769(b) of the California Public Utilities Code specifies that electrical corporations must file DRPs by July 1, 2015. There is no specification in the legislation as to whether future plans or revisions must be filed, or how the Commission should monitor the progress over the course of time for the entities that file plans. Investments in distribution-system infrastructure are long-term investments, both in terms of the physical, as well as the financial assets. In the opinion of the GPI, the Commission should establish a cycle for revising the DRPs, and a plan for ongoing monitoring of progress towards the plans during the course of each cycle. Our suggestion is to create a three-to-five year cycle between major overhauls of the plans, bolstered by annual progress reports and reviews.

13) Should the DRPs include discussion of how ownership of the distribution may evolve as DERs start to provide distribution reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable?

At this point, we do not envision a future in which the IOUs do not own and operate the major distribution circuits that serve California consumers within their service territories. DERs may indeed provide distribution-system reliability services, but we would expect that this would take place subject to contracts with the IOUs. Customer and/or third party ownership of micro-grids and interconnections to the distribution grid might very well occur, but the major distribution systems themselves are likely be owned and operated by the utilities.

Exceptions to this rule might occur in special cases, such as in Scotia, CA, which historically was a company town owned and operated by Pacific Lumber Co, with a local distribution grid owned and operated by Pacific Lumber. However, unless public utility law is changed, in most cases private ownership of conventional transmission systems is unlikely to be adapted due to the reticence of most investors to risk classification and regulation as public utility companies. Pacific Lumber in Scotia escaped classification as a public utility because the company did not sell the power to the households – it was provided to the workers as a benefit, as were the houses themselves.

14) What specific concerns around safety should be addressed in the DRPs?

The paramount safety concern for distribution-system planning should be the maintenance of the integrity and reliability of the system. Included in these concerns should be the safety of establishing and maintaining interconnections between DERs and grid, and the establishment of safety protocols for utility linesmen working on distribution circuits that have non-utility generators feeding energy into the circuit.

16) Appendix B to this rulemaking is a white paper that articulates one potential set of criteria that could govern the IOUs DRPs. Please review the attached paper and answer the following questions:

- *Integrated Grid Framework: the paper opens by presenting an 'Integrated Grid Framework,' what additions or modifications would you suggest be made to this framework?*

The GPI agrees with the need for a framework that embraces a holistic approach.

- *Integrated Distribution Planning: what, if any, additions or modifications would you suggest to the Integrated Distribution Planning section of this paper?*

The GPI endorses the approach described in the section of the report on integrated distribution-system planning and scenario analysis. We believe that the effort related to establishing rules for access to utility data should be significantly bolstered. We participated in Rulemaking R.05-06-040, which established confidentiality rules for RPS and related data, and we note that it was a grueling process. We expect the same to be the case here.

- *Distribution System Design-Build: what, if any, additions or modifications would you suggest to the Distribution System Design-Build section of this paper?*

The GPI recommends adding emphasis to two of the design elements included in this section of the report, openness to new and evolving technology, and the key role that the distribution IOUs will have to play in order to achieve success in realizing the potential of the future integrated grid.

- *Integrated Distribution System Operations: what, if any, additions or modifications would you suggest to the Integrated Distribution System Operations section of this paper?*

This section of the report discusses a variety of ways of operating the distribution grid of the future, which will include an increasing amount of DERs of all kinds. In the opinion of the GPI, the two key elements of this section of the report are smart-grid operations, and operation of the interfaces between transmission and distribution.

On page 17, the report states that RPS goals apply to both transmission and distribution. RPS targets apply to the overall mix of energy sources that power the grid in California, but they are not applied individually at the transmission system and distribution system levels. The targets are applied specifically to load serving entities in the state, without regard to whether the renewables are fed into the system at the transmission level, or at the distribution level.

- *Integration of DER into Operations: what, if any, additions or modifications would you suggest to the Integration of DER into Operations section of this paper?*

The GPI wishes to add emphasis to two of the elements included in this section, open access, and progress towards a plug-and-play architecture for DER of all varieties.

- *Integrated Grid Roadmap: what, if any, additions or modifications would you suggest to the Integrated Grid Roadmap section of this paper?*

The GPI believes that the roadmap section of the report provides an adequate starting point for the effort needed in this area. Ultimately, each service provider's roadmap should be the centerpiece of its DRP.

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Respectfully Submitted,

Gregg Morris

Gregory Morris, Director
The Green Power Institute
a program of the Pacific Institute
2039 Shattuck Ave., Suite 402
Berkeley, CA 94704
ph: (510) 644-2700
e-mail: gmorris@emf.net