BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's own motion to improve distribution level interconnection rules and regulations for certain classes or electric generators and electric storage resources.	Rulemaking 11-09-011 (Filed September 22, 2011)

CLEAN COALITION REVISED COMMENTS ON AMENDED SCOPING MEMO

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CLEAN COALITION REVISED COMMENTS ON AMENDED SCOPING MEMO

The Clean Coalition respectfully submits these comments on the amended scoping memo, dated September 26, 2012.

The Clean Coalition is a California-based nonprofit organization whose mission is to accelerate the transition to cost-effective local renewable energy that strengthens local economies, minimizes environmental impacts, and enhances energy security.

To achieve this mission, the Clean Coalition promotes proven best practices, including the vigorous expansion of Wholesale Distributed Generation (WDG) connected to the distribution grid and serving local load. The Clean Coalition drives policy innovation to remove major barriers to the procurement, interconnection, and financing of WDG projects and supports complementary Intelligent Grid (IG) market solutions such as demand response, energy storage, forecasting, and communications. The Clean Coalition is active in numerous proceedings before the California Public Utilities Commission and other state and federal agencies throughout the United States in addition to work in the design and implementation of WDG and IG programs for local utilities and governments.

I. Discussion

a. Overview

The Clean Coalition is supportive of many features of the amended scoping memo ("ASM"), in particular the priority given to addressing the key hurdle to expedited interconnection: increasing cost certainty early in the interconnection process. The ASM has rightly scoped this issue for early in Phase II, with a proposed decision scoped for Q2 2013.

We are troubled, however, by the apparent failure to recognize and give due weight to terms of the Settlement regarding the scope and schedule of Phase II, and the related positions previously expressed by Commissioners and staff.

The schedule outlined in the ASM is much delayed from the schedule proposed in the Settlement. Without action, the issues identified by the Parties will continue to severely hamper renewable energy development in California. This means continued higher costs for ratepayers, burdensome and even unmanageable study processes for utilities, procurement uncertainty related to project delays and withdrawals, and the economic, employment, and industrial development impacts associated with slowed deployment and expiring federal tax credits. With each gigawatt of delayed or discouraged renewable projects representing several billion dollars of missing direct investment (and associated revenues for the State), timely and effective resolution of the remaining issues is urgent. We feel that the pace of action by the Commission over the past half-year and as defined by the ASM does not reflect the necessary urgency.

Specifically, the proposed schedule in the ASM is six months later than the schedule envisioned by the Settlement. Moreover, it is almost certain to slip further, given recent history in many proceedings. We propose below a schedule that is both feasible and more in keeping with the Settlement. In contrast to the 18-month process called for in the ASM, the Settlement calls for a nine-month Phase II process. The Clean Coalition pushed for this nine-month timeframe and <u>expressly conditioned our support for the Settlement on this inclusion in the Settlement</u>. We raised this point in the prehearing conference and Commissioner Florio personally committed to do his best to ensure that this timeframe would be respected by pushing for a proposed decision by the end of 2012. And yet the ASM makes no mention of the nine-month timeframe in the Settlement; makes no mention of an expedited schedule for Phase II or the agreed reasons for needing an expedited schedule; and makes no mention of Commissioner Florio's personal commitment to an expedited schedule or a PD by the end of 2012. Clearly, a PD by the end of 2012 is not possible at this juncture because it took the

Commission six months to finalize the Phase I decision – the opposite of an expedited schedule. However, the Commission should respect the wishes of the settling parties and at the very least acknowledge the Settlement's call for a nine-month Phase II and explain, if such is the case, why such a timeframe is not feasible.

We also find the ASM's discussion of the settlement's scoping of issues for Phase II overly cavalier. At the urging of Commission staff, the Settlement Parties invested considerable time and agreed, in good faith, to delay resolution of pressing issues within the settlement process and instead scope these for a subsequent immediate second phase of the proceeding. This agreement was entered into in order to conclude the Settlement on a schedule requested by the Commission. The Commission also initially suggested the settlement process as the most effective way to resolve Phase I issues. So for the ASM to treat the Settlement's scoping of issues for Phase II as advisory and readily overlooked (as it does), while technically allowable as a point of law, does violence to the spirit of the settlement process and the credibility of the Commission.

The ASM does not request comments on the issues scoped for Phase II or the timelines specified in the ASM. Nevertheless, we offer below our comments on these issues, as well as the issues for which the ASM does request comments.

b. Specific recommendations

i. The schedule should be advanced by one quarter

Given the history described above, we recommend the following changes to the proposed schedule in the ASM, essentially advancing most items by one quarter, which we see as reasonable and feasible for an expedited schedule:

EVENT	ASM DATE	Clean Coalition DATE

Workshops – • Implementation of Interconnection Cost Responsibility, • Technical Operating Standards	Q4 2012/Q1 2013	Q4 2012/Q1 2013
Proposed Decision – • Distribution Group Study Process, • Standardized Forms and Agreements	Q2 2013	Q1 2013
Proposed Decision – • Rule 21 Compliance, • Applicability of Rule 21 to Commission Distributed Generation Programs, • Implementation of Interconnection Cost Responsibility	Q3 2013	Q2 2013
Proposed Decision – • Technical Operating Standards	Q4 2013	Q3 2013

ii. Scoping of issues

1. Distribution Group Study Process

The ASM scopes development of the Distribution Group Study Process as issue #1 and the Clean Coalition supports this prioritization. This was one of the issues scoped for Phase II in the Settlement, as part of the set of deferred issues (due to lack of time in the settlement process). Parties, including the Clean Coalition, have already submitted comments on the IOU draft proposals and we look forward to seeing revised proposals from the utilities.

2. Standardized forms and agreements

These items are also already underway in accord with the Motion to Adopt and Interim Procedure filed by parties March 2nd 2012, and parties have submitted comments. We look forward to seeing the revised versions shortly.

3. Applicability of Rule 21

The Clean Coalition agrees that this is a very important issue that needs to be addressed early in Phase II. We have long argued that the Commission has broad leeway to assert jurisdiction over interconnection and we again urge the Commission to seek briefings from the parties on their legal views regarding jurisdiction over interconnection.

4. Interconnection Cost Responsibility and increasing Cost Certainty

We offer first some general thoughts and perspective on this topic then address the ASM's specific questions in detail below.

The Clean Coalition is strongly supportive of this issue being included and we have been pushing for increased cost certainty to be the top issue in the Rule 21 reform process from the outset. The Settlement's full set of issues under the cost allocation and cost certainty rubric is as follows, and we urge the Commission to include all of these sub-issues in Phase II:

> Cost allocation and certainty issues, including but not limited to: earlier cost certainty, cost averaging, cost sharing, distribution system upgrades appropriate for rate-based support, data reporting to improve cost predictability, cost assignment of planned distribution system upgrades, curtailment as a method of avoiding triggered upgrades, development of an online portal for applying for a Pre-Application Report.

California's distribution grid interconnection process is hobbled by multiple factors related to the study requirements for individualized cost allocation, with many studies delayed an inordinate length of time. These problems include:

- Many applications will ultimately be withdrawn based on higher than expected interconnection costs or other issues
- Applications that will ultimately be withdrawn generally involve some type of interconnection study in order for the developer to make the decision to withdraw
- More importantly, these projects negatively impact the interconnection queue when they're withdrawn because of the shift in cost burdens
- Final cost responsibility is highly dependent upon which applications are withdrawn during the study process

Applicants request studies to determine whether a project is viable, and will use that information to direct resources to the best opportunities. The critical data for an interconnection applicant are interconnection costs and the timing by which costs are provided. Under the current procedures, cost responsibility cannot be determined until after studies are completed (or even long after interconnection is completed under the GIA's future liability provisions). As such, many projects that will ultimately be withdrawn, based on study results, must still be included in the studies. This results in greatly exaggerated generator impacts and cost estimates in preliminary and final studies, due to the withdrawal of a substantial number of projects in each study. Just as important, the withdrawal problem greatly reduces the opportunities for accelerated study procedures that depend on a project's electrical independence or ability to pass Fast Track screens.

If reliable cost responsibility information were available to applicants much earlier in the process, even prior to submitting an application or upon initial review, non-viable proposals would be identified early and withdrawn at that time. This would greatly reduce the number of post-study project withdrawals, and likely very substantially reduce the number of projects included in studies and their impact on accelerated review options, while increasing the accuracy of study results for all applicants. The availability of reliable cost responsibility early in the interconnection process will also allow applicants to receive and execute an interconnection agreement much earlier, without waiting for detailed study results. This would support easier coordination with procurement schedules, greater opportunity to participate in procurement programs linked with interconnection requirements, and dramatically earlier determination of queued procurement viability.

In short, allowing parties to obtain firm cost responsibility information early in the interconnection process would dramatically improve current problems with the interconnection of wholesale projects.

Clean Coalition's cost averaging proposal

To achieve early interconnection cost determination, it is necessary to decouple information on the cost responsibility for each applicant from its current dependence upon study results. Standardized interconnection pricing, available without detailed studies, should be achievable based on historical and current interconnection costs to the distribution grid, and the Clean Coalition recommends that parties confer further on the best options for achieving standardized pricing. Standardized interconnection pricing is similar to, but more reliable, than the "per unit cost guides" available to parties interconnecting to the transmission grid. Rather than providing per unit cost guides for distribution interconnection, we are suggesting that "per configuration cost guides" should be developed, with each "configuration" representing the most common types of distribution grid interconnection. Each configuration could be determined by the most common types of upgrades required for distribution grid interconnection, or through the aggregate load penetration, as discussed below, or through some other method.

SCE has suggested in workshops that the relatively low cost of interconnections to the distribution grid (where no transmission upgrades are required) weighs against this approach. We feel, however, that the delay in obtaining cost responsibility information, under current procedures (which can take up to a year and a half or longer to obtain), is as or more important than the costs themselves. Our proposal will allow parties to obtain reliable interconnection cost responsibility data early in the process and to sign an IA based on that information.

As a starting point, we suggest simplified cost averaging based on the aggregate coincident available load penetration, at the line segment, resulting from the serial addition of the applicant's proposed project. This formula would be applied for each kW of added capacity per application, as in the example in Figure 1.

Figure 1. *Clean Coalition proposal for averaging distribution-grid interconnection costs.*

Aggregate Resulting Generation vs. Load:	5%	10%	15%	25%	50%	80%	90%	>90%
Average Cost per kW:	$\$x_1$	$\$x_2$	$\$x_3$	$\$x_4$	$\$x_5$	$\$x_6$	$\$x_7$	$\$x_8$

Information for line segment load and queued generation or storage export capacity is readily available, and localized aggregate penetration levels should provide a firm foundation for defining average upgrade costs, although additional categorical factors may be appropriate. Initial screening may capture specific scenarios that would otherwise allow unusually high-cost projects within these categories.

Some lines can accommodate a given generation to load ratio more easily than others, for a variety of reasons, such as the type of equipment already installed at those locations when the distribution system was expanded or modernized, or upstream short circuit capacity variations. As such, we recognize that a simple DG penetration ratio may not be the perfect measure, but it may nevertheless be a strong starting point.

If information is available on circuits, line segments, or substations to further categorize or refine appropriate average costs, we support their inclusion as an adjustment factor. This calculation may result in a separate rate schedule for different classes of interconnection types and locations, or simply by local geographic region where a certain class may predominate. Factors such as short circuit capacity may not be possible to predetermine and may therefore still require initial screening. However, this process would be accomplished in days or weeks, instead of the months or years currently required for interconnection cost determination.

The goal need not be to determine average pricing that would accommodate all applicants, but as many as practical and feasible in the timeframe available for Phase II. If those applications requiring individual analysis can be identified through early review, allowing 80% or more of applicants in each study path to qualify for averaged pricing schedules, this improvement would still be very substantial.

Applicants will generally accept more expensive interconnection costs (within reason) in exchange for greater predictability and dramatically earlier cost certainty. This in turn would reduce the demand upon utilities to provide individualized and often interdependent cost analysis to each applicant before an initial commitment can be reached, and will save scarce engineering resources for interconnection studies for the projects that truly require full studies.

Cost averaging would not impact cost responsibility between utilities or ratepayers relative to applicants. This is the case because averaging will, if done accurately, not change the overall interconnection costs, by definition. However, both ratepayers and interconnection applicants would benefit from reduced processing time and increased certainty with respect to cost responsibility. This could also increase competition between generators and reduce queue congestion by allowing bidders to participate in procurement processes without speculative reservation of interconnection capacity years in advance, such as can currently be necessary with today's interconnection procedures.

Pre-Application Reports

With respect to the Pre-Application Report, we strongly urge the Commission to include the development of an online portal for Pre-Application Reports and for interconnection studies as part of this set of issues – as was the case with the Parties' description in the Settlement, which called for "development of an online portal for applying for a Pre-Application Report." We are very pleased to see that PG&E has already developed an online portal for interconnection applications under WDAT and will soon be expanding this capability for Rule 21 applications. Figure 1 shows a screen shot of PG&E's new fillable online application for WDAT:

Figure 1. *PG&E's new fillable online application for WDAT interconnection applications.*

Search Go

Manage My Account | Customer Service | Save Energy & Money | Environment | Education & Safety

- Emergency
- Contact PG&E
- Service Guarantees
- Start Stop & Move Service
- More Services
- Brochures & Forms
- SmartMeter™
- Outages
- Energy Choice
- Non-PG&E Utility Services
  - Departing Load
  - Electric Transmission Service
  - Generate Your Own Power
    - Distributed Generation
    - Net Energy Metering
    - Qualifying Facilities Converting to Merchant Status
    - Local Government Renewable Energy Self Generation Program
    - AC Disconnect Switches for Inverter-Based Generation
    - Secondary Markets
    - Wholesale Generator Interconnection

Generator Interconnection Request

The following information will be submitted via an online application process at PG&E's website

Note: Due to the nature of the online submission, certain information on the online application form may be required.

Step 1: Application Type & Generating Facility Info **Step 2: Contacts and Interconnection Info**
Step 3: Attachments & Submit

Application Type

* indicates required field

The undersigned Interconnection Customer submits this request to interconnect its Generating Facility with the Distribution Provider's Distribution System (choose one):*

- ○ Fast Track Process
- ○ Independent Study Process
- ○ Cluster Study Process
- ○ One-Time Deliverability Assessment pursuant to GIP section 4.22.1
- ○ Annual Deliverability Assessment pursuant to GIP section 4.22.2

This Interconnection Request is for (choose one):*

- ○ A proposed new Generating Facility
- ○ An increase in the generating capacity or a Material Modification to an existing Generating Facility

Requested Deliverability Status is for (choose one):*

- ○ Full Capacity (For Independent Study Process and Cluster Study Process only)
  Note: Deliverability analysis for Independent Study Process is conducted with the next annual Cluster Study – See GIP Section3.4
- ○ Energy Only

Project Name:*

Site address of existing or proposed generating facility project:

Street Address:*

City:*

County:* Select One

State:* California

Zip:*

GPS Latitude:* ?

GPS Longitude:* ?

Maximum net megawatt electrical output (as defined by section 2.c of Attachment A to this appendix) of the proposed new Generating Facility or the amount of net megawatt increase in the generating capacity of an existing Generating Facility;

Max net megawatt electrical output: MW

OR

Net megawatt increase: MW

This is a substantial first step for what we have described previously as "Interconnection 3.0" (i.e., increasingly automated interconnection procedures) and we have been liaising with PG&E about their new portals and how the best practices being pioneered by PG&E may be adopted and expanded by other utilities in California and elsewhere.

We look forward to working with the IOUs and the Commission in automating the Pre-Application Report process with an online portal, as called for specifically by the Parties to the Settlement. The key feature of an online portal will be not only efficiency for developers in submitting the application, but, more importantly, the ability for an automated process whereby utility interconnection data is matched to the particular application generally without requiring human intervention. The Report should be populated automatically, with only a quick review required by utility staff. This will require that the utilities create accurate databases with ongoing revisions, including all of the relevant data called for, including the data discussed in the next section.

The ASM poses a number of specific questions with respect to cost certainty, as follows:

> *Commission question: Developers of distributed generation have three tools available to evaluate potential locations of projects: (i) each utility's online interconnection capacity map ordered in D.10-12-048; (ii) the new integrated online Rule 21 and wholesale distribution tariff interconnection queues required pursuant to Rule 21, Sec. E.5.d; and (iii) the new Pre-Application Report set out in Rule 21, Sec. E.1. Please provide specific proposals for the publication of additional data not available within these tools that would enhance predictability of the costs and process of interconnection. Identify whether such data can be made available without violating the confidentiality rules set out in Rule 21, Sec. D.7.*

Maps

The Clean Coalition has been advancing this issue for a number of years, with substantial progress made in various areas. The utility interconnection maps are a major advance in providing developers knowledge about interconnection availability for specific locations. However, with respect to smaller projects, which are the focus of Rule 21, the maps lack a crucial datum: line section capacity. Screen M of the new Rule 21 requires that the project be less than or equal to 15% of the line section peak load. If the project exceeds this level it may go through a supplemental review process, rather than being rejected from Fast Track. This is a major improvement over the old Rule 21 because it allows projects matching up to 100% minimum coincident load to still pass Fast Track, in at least some circumstances. That said, there are major new uncertainties in the supplemental review process, with a number of new screens added as safeguards, and we won't know how well it works, if at all, until the utilities begin to use the new process.

Regardless, it is better for all concerned if an applicant passes Screen M and avoids the supplemental review process (as one key point, the supplemental review process will cost $2,500, three times the Fast Track fee). Having line section data is very important in allowing applicants to choose locations where their projects are likely to pass Screen M and/or the Supplemental Review screens. The utility interconnection maps currently show only circuit level data, not line section data. Accordingly, developers have no way of knowing if a project will pass Screen M or the Supplemental Review screens, based on the maps. We have recommended for some time that the maps include line section data as well as circuit level data, but to no avail at this juncture. We understand that line section data is not fully developed on many circuits. However, with the introduction of smart metering, unprecedented increases in interconnection studies, and increasing electronic cataloging of the location of sectionalizing devices, much useful information could be made available.

More broadly, per D.10-12-048, ongoing improvements in the functionality and accuracy of maps has been required by the Commission. An easy and major improvement would be in consistently supporting search and sorting functions in relation to the map and screening data, and online spreadsheets to identify locations by relevant criteria. For example, it would be very useful to include the ability to rank order all circuits within a zip code by current and queued penetration level, as opposed to clicking on each point on a map to hunt for optimized locations. While some search or ranking functions have been provided in some cases, such functionality is currently very limited and is not available across all three IOUs. It is essential to make this information easily available in order to make best use of available capacities and existing investments and direct new deployment to the locations best able to accommodate it without extensive delay, cost, and uncertainty.

Pre-Application Reports

We made progress during Phase I in this proceeding when the utilities agreed to provide a Pre-Application Report (PAR) for a flat fee of $300, but only for information that is readily available. If line section data is readily available, it should be included in the PAR, but, again, we won't know how often this data will be included until this option is pursued by developers many times and we see the results from the utilities. The PAR language in the new Rule 21 states:

> The Pre-Application Report will include the following information if available:
>
> a. …
> b. Relevant Line Section(s) peak load estimate, and minimum load data, when available.

Time will tell how the utilities respond to PAR requests for line section data, in terms of what is considered to be "available." Given the discussions in the settlement process, we are not optimistic that this information will as a general matter be included in PARs. We are, however, hopeful that the PAR process and/or the interconnection maps may be readily modified to allow enough data to be supplied to developers to allow developers to make the required calculation re line section limitations under Fast Track.

Queue information

The staff question also asks whether the new Rule 21 queues will include information helpful to developers scouting for new locations. Some information can be gleaned from the new queues, but this information is circumstantial, based on projects near the new project being contemplated, and this circumstantial information is far from definitive. At best, the queue information will allow for more educated guesses, but the Clean Coalition is seeking a better solution than this. The critical information always comes back to cost. There is considerable interest in releasing the results of interconnection studies, as is already done by both public utilities and investor-owned utilities such as Pacificorp. Making interconnection studies public would greatly increase transparency in the interconnection review process, dramatically increase accountability for consistency, and provide valuable insight on the interconnection experience of prior applicants at any given location. All parties recognize, however, that information on prior experience is not necessarily predictive, and standardized interconnection pricing, through cost averaging or other mechanisms, would go much further toward providing predictable costs in project siting and commitment decisions.

In sum, we recommend the following improvements to address the Commission's question:

- Add a spreadsheet containing all of the interconnection map data, in searchable form, at the same website as each utility's interconnection map
- Establish what "when available" means with respect to supplying line section data and other data in the PAR.
- Add the locations of line sectioning devices to the interconnection maps
- Work with the utilities to determine how smart meter data can be used to calculate or estimate minimum and peak circuit and line section data, and publish this information in the interconnection maps and spreadsheets, and/or make this information available to parties requesting a PAR

Commission question: Pursuant to Commission policy, and as expressed in Rule 21, Sec. E.4.e., developers of generating facilities interconnecting to the distribution system under Fast Track and the Independent Study Process pay for the costs of distribution system upgrades triggered by their project. As a consequence, the first-queued may pay for infrastructure capacity that is used by later-queued generating facilities without

> *incurring costs. Please provide specific proposals for new cost arrangements among developers of distributed generation, including, for example, mechanisms by which the triggering developer may receive fees or other compensation for infrastructure capacity used by later-queued generating facilities.*

We note first that cost averaging, or other mechanisms for standardizing interconnection costs, would obviate this issue while also providing rapid, simplified and firm costs to developers.

The Clean Coalition is not opposed in principle to this proposed cost sharing mechanism (later-queued applicants reimbursing a prior generator), but we feel that it is not likely to be useful in practice and may have unintended consequences. The opportunity for potential partial reimbursement of upgrade charges is clearly uncertain and therefore must be discounted in any decision regarding development costs and the price of offered energy. Additionally, projects proceeding through Fast Track and group studies would be largely unaffected, further limiting any positive consequence because the Independent Study Procedure is rarely used under WDAT and will probably be rarely used under Rule 21. As such, this approach will do little to benefit ratepayers or to reduce risks for new energy suppliers. At the same time, future projects may have their costs and prices negatively impacted by imposing cost responsibility for prior upgrades. Determining which sites are subject to prior upgrade cost responsibility would add complication and interconnection cost uncertainty to a site selection process already mired in complexity and unpredictability.

We are also concerned that if this new policy for sharing upgrade costs is pursued, it may exacerbate the likelihood of a utility seeking more costly upgrades than strictly necessary ("gold-plated upgrades", with the $25 telemetry costs as just one example) by making it seem that developers have mitigation tools at their disposal for reducing costs. While larger upgrades can be more cost effective in the long run, and should be pursued to support greater adoption of local generation, burdening the first or next queued applicant with such costs is both unfair treatment and discourages all applicants, dampening development of local generation. We urge the Commission to obtain relevant data from the utilities in order to flesh out the situation empirically before pursuing this proposal.

> *Commission question: Please provide proposals for new financing and ownership structures of distribution system upgrades that can reduce the overall cost of interconnection without ratepayer impact, including any legal issues that may need to be addressed to enable these proposals to be implemented.*

We also offer here some general observations followed by specific recommendations.

All interconnection upgrade costs are necessarily reflected in the energy prices offered by generators – ratepayers will ultimately either compensate the generator or the utility through direct energy rates or additional delivery charges, depending on who capitalized the initial cost. The goal of this proceeding should be to promote cost-effective development and optimal use of grid capacity in conjunction with long-range planning and policy objectives (such as increased clean local generation in support of capacity, reliability, economic and emissions goals). Rate impacts must consider avoided costs and locational benefits of alternative system investment approaches. Very large ratepayer investments totaling tens of billions of dollars in additional transmission may be avoided and more cost-effectively redirected to enable generation near point of use within the local distribution system.

Current practices also create unnecessary costs by requiring project developers to capitalize the cost of upgrades, then transfer ownership to the utility, creating an income tax liability for the utility that is then reimbursed at additional cost by the project developer. However, the developer loses investment tax credit eligibility and depreciation value on these assets and gift tax when ownership is transferred, effectively nearly doubling the net cost of these upgrades – a cost ultimately born by the ratepayer through higher generation charges. These factors must be considered when evaluating relative ratepayer impact or neutrality.

The Clean Coalition has previously advocated for rate-basing certain distribution grid upgrades, and we reiterate this proposal here. Specifically, we recommend the following system for ensuring that there is no cost-shifting to ratepayers (cost savings should, in fact, result):

- Utilities must complete a Distribution Grid Upgrade Plan (DGUP), looking ahead three years, with the purpose to accommodate the increasing number of distribution-interconnected projects expected to come online under various new and existing renewable energy programs. Each DGUP will identify areas most suited for distribution-interconnected generation, including as a key criterion the cost-effectiveness of such upgrades. Cost-effectiveness must be judged based on the transmission-interconnected alternative for similar renewable energy projects. The first plan shall be due no later than six months after a decision is issued in this proceeding, and every two years thereafter, with parties providing opening and reply comments on the plans prior to finalization by the utilities.
- Utilities should be authorized to rate-base reasonable distribution grid upgrades (generally below 69 kV, but this figure varies by utility) triggered by renewable energy project interconnection requests, regardless of the size of the project, insofar as these upgrades are previously identified in their DGUPs. The Commission should consider transmission line rate-basing rules in determining the manner in which utilities may rate-base distribution grid upgrades, but with <u>no up-front payment required from developers</u> (as is the case for transmission upgrades).

No cost shifting will occur if DGUPs are well-crafted because

- Under the current procedure, the developer capitalizes the cost of all upgrades but transfers ownership to the utility. As a result of the transfer:

1. The utility is potentially subject to an income tax charge of the transferred value, resulting in an additional cost (charged back to the developer).
2. The developer is unable to take advantage of the 30% Investment Tax Credit on the costs of the upgrades
3. The developer is unable to depreciate the cost of the upgrades

Taken together, these three impacts of having the developer pay for interconnection upgrades and then be required to transfer ownership to the utility more than doubles the actual net effective cost of the upgrades – a cost which is reflected in higher energy rates for ratepayers.

Moreover, the utility avoids triggering potential income tax charges and can apply advantageous financing, investment and depreciation terms if directly financing the upgrades. Alternatively, these costs can be avoided if the actual ownership of the upgrades is legally retained by the developer while control is ceded to the utility. Equipment replacement insurance charges imposed on the seller by the utility at 5% per year result in the seller paying twice for the equipment they are required to give to the utility over a 20-year contract, further increasing costs ultimately reflected in PPA rates for ratepayers.

Last, the cost of money for utilities is substantially less than for most developers, who are higher risk borrowers than utilities. As such, having utilities rate-base distribution upgrades rather than having developers pay these costs upfront will save ratepayers additional money, all else being equal.

Details of our proposal will need to be worked out further, with adequate safeguards to ensure that there is no cost shifting to ratepayers.

While we argue that the ratepayer is indifferent as to the ownership and capitalization of upgrades, and is only impacted by the combined total impact on energy and T&D charges, it is possible to maintain developer cost responsibility while avoiding the excess costs outlined above through the application of distribution system interconnection impact fees – what we describe as the "Impact Fee Option." Under this approach, the developer does not directly finance and transfer ownership of facilities, but is instead assessed a fee by the distribution service provider that maintains ratepayer neutrality. This arrangement may allow such costs to be eligible for ITC and depreciation value while also potentially avoiding the income tax consequences of transferring ownership of facilities. While the ratepayer remains neutral relative to the facilities upgrades, ratepayers will benefit from the lower energy costs related to the potential substantial improvements in tax consequences. Note that such Interconnection Impact Fees may reflect a proportional flat rate, standardized average costs by impact classification, or customized fees based upon any required interconnection studies, as determined appropriate. Again, this option will need to be fleshed out further.

> *Commission question: Pursuant to Rule 21, Sec. E.4.c., an interconnection customer under Rule 21 is permitted to complete the interconnection process even if earlier queued generating facilities have not completed the process. Under this framework, significant cost uncertainty may result. Please provide specific proposals to permit a "shovel-ready" project to complete the interconnection process and reduce this cost uncertainty without violating the open access and first-come, first-served principles applicable to the transmission and distribution interconnection queues.*

The Clean Coalition feels strongly that all costs for which an applicant is held responsible must be identified in the study process and must not change after the signing of a GIA. We agree entirely with the question above that "significant cost uncertainty may result" from the wording in the new Rule 21, and we objected to the language in Sec. E.4.c on many occasions during Phase I and to similar language in the revised WDATs during the WDAT reform process in 2010 and 2011. This kind of uncertainty undermines the interconnection process because very few developers or financiers will enter into an interconnection agreement if they fear a substantial new interconnection charge at an undetermined future date. This is another area that will benefit from empirical data because we and other parties have at this point no understanding of how frequently applicants have been found liable for additional interconnection costs after a GIA is signed under the WDAT, or how common this situation may be under the new Rule 21. We urge the utilities to shed some light on these issues with real-world data.

As a solution to the cost uncertainty issues highlighted by the Commission's question, the Clean Coalition recommends that a balancing account (with or without standardized pricing/cost averaging) be created by each utility that will pay for any costs found to be necessary for particular projects after those projects have signed a GIA. Another key change that will ensure no cost shifting to ratepayers is to end the practice of providing refunds to developers for interconnection costs that turn out to be lower than quoted in the Facilities Study or Phase 2 study; instead of refunding these amounts they will fall into the utility's balancing account. The net effect of these two changes should be revenue neutral because the instances where new charges are found after a GIA is signed will, on average, be balanced against the refunds that are now deposited into the utility balancing account.[1]

If the account develops an ongoing surplus, these excess revenues may be distributed proportionally to contributors. A deficit in the account may be addressed by a fractional increase in interconnection charges or a risk insurance fee. The fundamental public benefit achieved through the resulting increased certainty and accelerated decision processes far outweigh the negligible risk to ratepayers, and the reduced development risk across innumerable projects will result in lower energy costs for ratepayers that will likely far exceed any costs. Again, more data will be required to determine if it is likely that these two changes will net each other out – and we urge the utilities to provide the required data in this proceeding.

[1] For example, if the resulting accelerated development and reduced risk allows the offered/accepted cost of energy (the PPA rate) to be just 0.1¢/kWh lower, ratepayers would save $32,000 over a 20 year contract for each MW, enough to offset a $300,000 unanticipated deficit on every 10 MW of new capacity (Assuming 1600 MWh/MW capacity per year for 20 years = 32,000 MWh).

We look forward to fleshing out these ideas during this proceeding.

5. Compliance with Rule 21

The Clean Coalition agrees that compliance issues should also be part of Phase II, and this set of issues was scoped as #6 in the Settlement list of issues for Phase II. Far too often, schedules and deadlines are created in various contexts that aren't adhered to. We look forward to helping ensure better compliance with Rule 21 deadlines and other compliance issues. The Settlement's description of this set of issues included "reconsideration of timelines" and this issue should be added to the scope of Phase II in the ASM. While we see some major improvements in terms of timelines in the new Rule 21 and the proposed DGSP, we still see much room for improvement. And <u>if timelines are not re-visited in Phase II it will likely be years before they are re-visited</u>. The time is now for delving further into these key issues, which should include detailed discussion of the potential for online portals and automation of at least some aspects of the study process to significantly reduce various timelines for interconnection ("Interconnection 3.0").

6. Technical operating standards

This issue should expressly include telemetry issues, which was scoped as issue #1 in the settlement. By "telemetry issues" we mean the costs and technical requirements for telemetry equipment, which have often been far more than strictly required. This is increasingly becoming a serious issue. For example, two interconnection studies provided to the Clean Coalition for solar projects seeking interconnection to SCE's sub-transmission grid include telemetry cost exceeding $20 million, and total interconnection costs exceeding $40 million. The total equipment and construction cost for the project is projected to be about $40 million, so these telemetry costs represent about 100% of the total project cost without telemetry. These exorbitant cost projections resulted from SCE's requirement that every project include fiber optic telemetry. Satellite-based telemetry could be completed at a tiny fraction of the projected cost for fiber optics, highlighting the need for the Commission to re-visit this issue and work with the utilities and stakeholders to create a rational set of standards for telemetry.

7. Issues that should be added to Phase II

While the Clean Coalition agrees that the issues described above should be part of Phase II, there are issues that the parties scoped for Phase II that are higher priority. Again, <u>the Commission should not ignore or dismiss the parties' careful and time-consuming recommendations for the scope of Phase II.</u>

Specifically, Phase II should include what the parties scoped as issue #2: "Reconsideration of technical limits within Rule 21: Fast Track size limits, 15% screen, development of further objective criteria." This set of issues is highly important to the success of Rule 21, as is clear from its placement on the short set of issues that the parties agreed to in the Settlement. Fast Track size limits, the 15% screen and development of objective criteria for various tests in Rule 21 (as opposed to the oft-cited "engineering judgment") are key for real interconnection progress. The 15% screen is problematic for many reasons, as highlighted by NREL and other parties during Phase I and in a later report entitled "Updating Interconnection Screens for PV System Integration." At the least, the Commission should weigh in regarding the appropriate process for how the 15% screen may be revised in a manner satisfactory to all parties.

The Clean Coalition is supportive of the new Supplemental Review process whereby applicants that fail the 15% screen may be tested under a 100% minimum coincident load alternative, but there are many potential pitfalls in the new Supplemental Review screens created by new safeguards. Regardless, the Supplemental Review process doesn't resolve the underlying issue as to whether the 15% peak load screen is the appropriate number.

Similarly, the Fast Track size limit (up to 3 MW but lower in some cases) was never addressed adequately in Phase I. The Clean Coalition argued that a size limit is entirely moot because the purpose of the screens is precisely to determine what size project can pass Fast Track. The only counterargument offered by the IOUs was that applicants should be given a size limit to set expectations before applying. But the new Pre-Application Report (for $300) will do exactly that. Accordingly, there seems to be no good rationale for an *a priori* size limit for Fast Track and we strongly urge that this issue be included for further discussion in Phase II.

The Parties also scoped the following for Phase II Issue #4: "Study Deposits, pursuant to which the IOUs shall collect and provide data on the actual cost of system impact studies and facilities studies." Since Phase I ended, the Clean Coalition has obtained additional information from the utilities lending further support for reforming study deposit amounts. In particular, in response to our motion for additional interconnection data, submitted on Dec. 21, we obtained the following data (summarized for convenience as Figure 2):

Figure 2. *SIS and FS costs for SCE and PG&E 2009-2011 (WDAT and Rule 21).*

		SIS costs	FS costs
SCE	**Average**	$9,836	$11,996
	Max	$42,957	$62,702
	Min	$1,555	$1,928
	St. Dev.	$9,887	$15,373
	Median	$6,036	$3,932
PG&E	**Average**	$9,194	$18,074
	Range	$627-$29,668	$3,189-$27,520
	St. Dev.	$6,487	$11,451

The SIS deposit required under the new Rule 21 is $50,000 plus $1,000 per MW for ISP or the cluster process (up to a maximum of $250,000), but $10,000 for projects under 5 MW for an SIS and $15,000 for an FS. All of these figures are, however, far too high when we consider the data in Figure 1. The average costs for SIS for SCE have been less than $10,000 and only slightly above $9,000 for PG&E.[2] We will likely be recommending, based on this data, that the SIS deposit be reduced to $10,000 and the FS deposit reduced to $15,000. The above data should, at the least, demonstrate that this is an important issue that needs to be addressed in Phase II.

Similarly, Issue #4, just described above, includes collection of additional data on the cost of studies. The Clean Coalition will be submitting discovery requests to the IOUs, pursuant to discussions with Commission staff about the appropriate procedure for obtaining additional data in this proceeding. We also urge the Commission to be proactive in seeking comprehensive interconnection data from the IOUs, following up on the April 27, 2011, data request the Commission sent to the IOUs after working with the Clean Coalition to craft the request. That request led to the data presented in the Commission's 2011 Q3 RPS report on distribution grid-interconnected RPS projects. This data was helpful but far more sparse than we will need in this proceeding in order to achieve optimal reform.

II. Conclusion.

The Clean Coalition urges the Commission to adopt the changes we have recommended above for the scope of Phase II and the proposed schedule. Again, Phase II is, by the consensus of the parties, to be an expedited proceeding and the changes we recommend above help ensure that this is the case.

[2] The median cost for these studies is actually the most appropriate figure to use when setting study deposit amounts, but we don't have median costs from PG&E at this point. We hope to obtain median cost data from PG&E in Phase II, at which point we will likely revise our recommended deposit amounts.

Respectfully submitted,

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