October 8, 2021

To: California Public Utilities Commission

Re: Comments on Draft CPUC DER Action Plan 2.0

I. INTRODUCTION

The Clean Coalition lauds the Commission for developing a DER Action Plan 2.0 that will considering the changing landscape of the energy grid as the state decarbonizes and electrifies throughout the 2020s. It is of fundamental importance that the Commission take this overarching five-year plan as an opportunity to acknowledge the value of DER and the cost-effective grid of the future we can transition to by smartly siting local resources.

II. DESCRIPTION OF ORGANIZATION

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 distributed energy resources ("DER") — such as local renewables, demand response, and energy storage — and we establish market mechanisms that realize the full potential of integrating these solutions for optimized economic, environmental, and resilience benefits. The Clean Coalition also collaborates with utilities, municipalities, property owners, and other stakeholders to create near-term deployment opportunities that prove the unparalleled benefits of local renewables and other DER.

III. COMMENTS

<u>Track 2</u>

Vision Element 2A: Utility infrastructure businesses processes, including planning, all-source resource acquisition, and operation conditions and community needs, and seamlessly integrate cost-effective distributed energy resources.

Action Element 2: By 2022, CPUC staff documents all existing Distribution Investment Deferral Framework requirements into a formal Guidelines document to be updated annually or as reforms are implemented.

Documenting the current DIDF process, which is needlessly one dimensional and does very little to encourage the deployment of DER, is not the most valuable usage of the CPUC Staff's time. The DIDF only considers two options — a deployed FOM DER solution or a traditional infrastructure upgrade — a narrowminded dichotomy that explains why there has been very little success in recent years. In 2021, PG&E approved **zero** candidate projects despite the large number of upgrades requested. The DIDF does not need to be compiled, it needs to be significantly expanded to include a range of other solutions. DER are multi-functional resources that can offer resilience, GHG reduction benefits, and lessen the amount of energy that needs to be imported from the transmission grid, whereas traditional infrastructure only offers one value stream. The newly approved DER Deferral Pilots, although a step in the right direction, are only a small step rather than a full stride; there is a pilot for DER on either side of the meter, an arbitrary distinction that precludes the deployment of blended DER sited across the distribution grid. DER aggregations that include FOM and BTM resources, energy efficiency, dStatcoms (for Conservation Voltage Reduction), microgrids, and other non-wires alternatives should be viewed as tools to create a more dynamic grid and lessen the need for future upgrades rather than as an afterthought to the Distribution Planning Process. Instead we propose:

1. **By Q3 2022, CPUC staff should publish a preliminary list existing DER and emerging technologies to expand the existing DIDF in 2023.**
2. **By Q4 2022, the High DER proceeding should solicit stakeholder input and compile a final list for Commission approval by Q1 2023.**

Action Element 6: By 2023, CPUC staff completes a technical report on Distribution Resources Planning Data Portals improvements and conducts a stakeholder process to identify and explore potential updates and additional data to host, with the goal of increasing portal usability and usefulness for DER integration.

The Clean Coalition appreciates the thought that was put into this Action Element. Developers need accurate data to determine the best locations to site new projects and what upgrades will be necessary given the remaining hosting capacity on a feeder. Abundant information not only reduces a developer's uncertainty about project costs, but also improves the likelihood that an Interconnection Request will be approved. **That is information that should be available now to increase the pace of DER deployment throughout the state.** Any organization that has experience with project development and the interconnection process has struggled using the Data Portals and will likely have suggestions on improvements. In reply comments in the High DER proceeding (R. 21-07-017), the Clean Coalition listed a series of changes:

- ICA maps do not indicate which violation is limiting the integration of generation. Definitions on ICA User Guides state that either thermal, voltage, distribution protection, or operational flexibility violations could be the issue. Instead, each feeder segment should be more transparent and indicate the limiting factor to the integration of more generation.
- Each IOU's interactive ICA map should be available without the need to sign in or request access. Currently, for PG&E's ICA map, it is necessary to create login credentials before beginning use. To use SDG&E's ICA map, a user needs to request access, which often requires multiple days of waiting before a response, and then create login credentials. SCE's interactive ICA map, on the other hand, provides immediate access without the need to register or create login credentials.
- Each of the IOU's interactive ICA maps should provide an easy way to download the ICA spatial data in multiple formats (GEarth, geodatabases, etc). So far, PG&E and SDG&E, allow users to download just ICA geodatabases, but only after users create login credentials and/or request access, whereas SCE allows users to download KML, shapefile, XML and GeoJSON formats of ICA spatial data through its interactive ICA map.
- The IOUs should disseminate open access instructions on how they created their interactive ICA maps so other Load Serving Entities (LSE) across the nation can replicate the process.

- There should be an opt-out feature for the 15/15 rule, allowing for confidentiality of a sites' load profile if specifically requested by a developer rather than limiting access to information, irrespective of a developer's wishes.

Promoting transparency, open access, and an easy-to-use Data Portals will help pave the road to seamless DER integration. Therefore, this action element should be broken down into three steps:

1. **Work with stakeholder to compile a list of changes that should be made to the Data Portals and any proposed solutions by Q1 2022.**
2. **Implement consensus reform, via the High DER proceeding, by the beginning of Q2 2022.**
3. **By the end of Q3 2022, CPUC staff completes a technical report on the remaining Distribution Resources Planning Data Portals improvements and conducts a stakeholder process to identify and explore potential updates and additional data to host, with the goal of increasing portal usability and usefulness for DER integration.**

Vision Element 2B: Utility operations continuously improve interconnection performance, leading to greater transparency, speed, and cost certainty.

> ***Action Element 2: By 2022, utilities use a transparent technical review process to approve, after determining that safety and reliability requirements have been met, the use of technologies or products that can reduce the cost of DER implementation of optimize the performance of DER (e.g., lower cost relays, multi-port utility revenue meters).***

Clean Coalition agrees that new products capable of improving the deployment and performance of DER should be sought out and approved to reduce the hurdles to market adoption. With that being said, it is concerning that there isn't an ongoing process to expedite the review process for a technology at any given time. We recommend that the "transparent technical review process," be conducted annually, a necessary step to ensure that progress goes at the pace of the market rather than being held back by the utilities. The new Action Item should read:

1. **By 2022, and annually thereafter, utilities use a transparent technical review process to approve, after determining that safety and reliability requirements have been met, the use of technologies or products that can reduce the cost of DER implementation of optimize the performance of DER (e.g., lower cost relays, multi-port utility revenue meters).**

Vision Element 2D: Utilities integrate the anticipated impacts of electrification into distribution planning to maximize public benefits and minimize costs and to optimize deployment of complimentary and supporting infrastructure and distributed

Action Element 1: By 2023, CPUC staff completes a comprehensive, data-driven, electrification impacts study to estimate the scope of distribution grid buildout and identify opportunities to mitigate costs.

Track 2 Proposed Action Elements

Proposed Action Element 1: Implement short term Performance Based Regulations by Q3 of 2022.

Effectively implementing the action items in Vision Element 2A has the potential to completely change the way the grid is operated and guarantee that distributed generation is able to participate in all energy markets. Such a large paradigm shift requires changes to the existing utility business model to incentivize the creation of a two-way grid capable of seamlessly hosting a large number of DER. The road to achieving such a vision, as laid out by Track 2 of the DER Action Plan, necessitates utilities that are active collaborators rather than constantly fighting to preserve existing revenue-making opportunities.

The Commission has acknowledged an end goal — working to determine the feasibility of a Distribution System Operator ("DSO") — and has already agreed to study the viability of a DSO as part of the High DER proceeding (R. 21-06-017). Rather than waiting until the entire study process has been completed, an interim step to begin the transition should be working on the role of Performance Based Regulation ("PBR"), particularly in the short-term. Continuing to guarantee the utility's a reasonable rate of return is essential to speeding up the transition to a two-way grid, as has been demonstrated by the partnership between HECO and the Hawaii

PUC.[1] Since there are existing case studies about the potential of PBR, even while Energy Division staff completes a long term studies about a DSO model, testing PBR is a low-hanging fruit that can be done independent of other actions.

Proposed Action Element 2: Approve the deployment of a Community Microgrid capable of substation-level backup power by the end of 2022.

With the existential threat of climate change causing a greater number of fires and extreme weather events, the number of outages due to reliability issues and Public Safety Power Shutoffs (PSPS) will continue to increase over the 2020s, making large-scale resilience solutions all the more important. The Commission should demonstrate its commitment to a DER future by approving a Community Microgrid capable of providing substation level backup power in a load pocket or high fire threat district. To date, the Microgrids proceeding (R. 19-09-009) has avoided the subject of Community Microgrids, particularly when it comes to substation-level backup power. Rather than use aggregation of BTM solutions, the Commission approved temporary natural gas generation, without ever considering aggregations, Virtual Power Plants, or Community Microgrids. Deploying a widespread resiliency solution like a Community Microgrid would significantly reduce the barriers to the widespread proliferation of microgrids across the state as well as expanding the Distribution Planning Process.

Proposed Action Element 3: Increase the amount of automation in the interconnection process, starting with a report by each utility about reasonable changes, published in Q2 2022, and reform implemented in Q1 2023.

Clean Coalition and GPI produced a joint interconnection report as part of the R. 17-07-007 Interconnection Working Group 2 called "Interconnection Automation and Streamlining Opportunities: Preliminary findings and recommendations." Each of the recommendations contained within the Issue 8 Appendix is as relevant now as when the report was published in October 2018. We wish to highlight the effect that automating/frontloading will have by

[1] The CPUC has an existing MOU with the HPUC related to information sharing and the climate crisis. That relationship should be used to leverage information about the practical viability of PBR.

providing applicants with cost certainty about the necessary infrastructure upgrades. The earlier a developer can have certainty, the smoother the planning, permitting, and constructions processes will be. From the perspective of the utility, an initial investment will result in a more efficient allocation of resources, allowing staff to focus on streamlining interconnection in other areas.

> ***Proposed Action Element 4: In concert with DIDF reform, create an approval process for alternatives that increase the hosting capacity of a feeder in the place of some distribution network upgrades.***

For the planning process to fully incorporate DER and other emerging technologies, the focus should be optimizing the grid rather than strictly focusing on infrastructure upgrades. If a project developer is able to increase the hosting capacity of the feeder, it should be approved in place of a physical infrastructure upgrade.

> ***Proposed Action Element 5: Automatically grant BTM resources deliverability as part of the interconnection.***

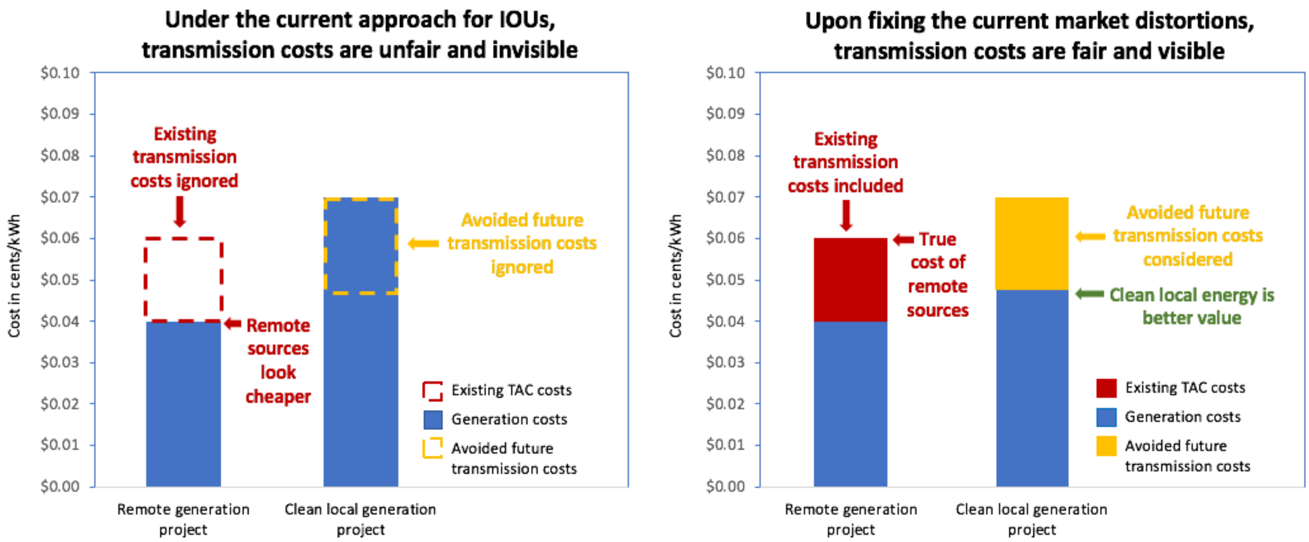
While it is an important economic opportunity, achieving deliverability takes significantly longer than it should, which is a barrier to market entry that can, and should, be resolved. In addition to increasing the pace of DER deployed, it could also help the state utilize BTM DER during emergency events (e.g., an opt-out Load Reduction or other Demand Response program).

<u>Track 3</u>

Track 3 Proposed Action Elements

> ***Proposed Action Element 1: Study the market distortion caused by the way Transmission Access Charges are allocated to ratepayers and consider a Transmission Energy Downflow ("TED") solution.***

TAC, which are charged by the IOUs to recover the cost of transmission infrastructure, artificially depress the value of DER, creating a market distortion through the way in which they are assessed to IOU customers. Because current TAC in IOU service territories are calculated at the customer meter, rather than at the transmission-distribution substation, all energy is charged that 2 cents/kWh TAC as if it originated from the transmission grid.



Existing transmission costs, currently averaging 2¢/kWh, should be added to the cost of remote generation that requires use of the transmission grid to get energy from where it is generated to where it is used. Future transmission investments, currently averaging 2.5¢/kWh in the evenings, can be avoided via dispatchable local generation, and that value should reduce the evaluated cost of local generation. When correctly considering ratepayer impacts of transmission costs, dispatchable local generation provides an average of 4.5¢/kWh of better value to ratepayers than is currently assumed in the majority of instances.

If the TAC market distortion were fixed, through Transmission Energy Downflow — properly assessing TAC at the transmission-distribution substation rather than the customer meter — the true cost of bulk power projects will be revealed. In comparison, DER, which are clean and multi-functional resources, will provide much better value. This is the way that the municipal utilities currently meter TAC, demonstrating the viability of the solution.

Proposed Action Element 2: Develop a series of recommendations on FOM interconnection reform based on developer experience and past BTM interconnection reform.

The Clean Coalition has experience with the FOM interconnection process and understands the cost and time uncertainty that accompanies it. No part of the FOM interconnection process is determinative; every step has a range in both amount of time and money that is necessary before the next step can take place. Applicants are unable to conclusively estimate what it will take to complete the interconnection process from publicly available information and also face significant delays during interconnection impact and cost responsibility studies. As a result, when compared with BTM projects, FOM projects cost more than 8 times as much, with an average cost of $312,000 — and they take more than twice as long before an application is approved, with an average of 723 business days. Uncertain timelines, potentially taking around two years, can be just as devastating as high interconnection costs. Projects that get stuck in the interconnection queue languish and are more likely to fail as time passes, particularly if a project bounces from department to department and there is not one point of contact at the utility that a project developer can reach out to. Attached along with these comments is a series of lessons on FOM interconnection based on the Clean Coalition's Valencia Gardens Energy Storage ("VGES") project, a partnership with the CEC and PG&E. Commission Staff should solicit information from organizations that have had similar experiences with the FOM interconnection process and takes lessons learned from steps the Interconnection proceeding has taken streamlining the BTM interconnection process to compile a full list of necessary reforms.

IV. CONCLUSION

The Clean Coalition appreciates the opportunity to submit these comments and looks forward to taking action at the Commission to help transition to a High DER future and a two-way grid.

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