October 15, 2018

Via Electronic Filing

Chair Iwase and Honorable Commissioners
Public Utilities Commission, State of Hawai‘i
465 S. King Street, Room 103
Kekuanao‘a Building
Honolulu, HI 96813

Re: Docket No. 2018-0165: Public Comments of the Hawaii PV Coalition

Honorable Commissioners:

Pursuant to Order No. 35569,[1] the Hawaii PV Coalition ("HPVC") respectfully submits, through its undersigned counsel, the following public comments regarding the Hawaiian Electric Companies' ("HECO's") Integrated Grid Planning Report ("IGPR") and the related September 25, 2018 workshop.

HPVC appreciates the Commission's effort to establish an integrated planning approach that "coordinates and informs planning across all levels of the power system (resource, transmission and distribution), and that ensures safe, affordable, and reliable service to customers."[2] HPVC also agrees the integration of these three approaches "will present significant challenges;"[3] and emphasizes the significant risk of missed savings opportunities for grid modernization, deferrals or alternatives to traditional utility infrastructure investments, and renewable integration benefits across all power system domains if the planning process is structured to prioritize utility-scale supply side resources over distributed energy resources ("DERs") as a predetermined preferred resource for meeting grid needs.

Despite these challenges, we are optimistic that a well-crafted approach can be established, and that integrated resource planning outcomes could unlock enormous opportunities for creativity, innovation and ratepayer saving. To this end, HPVC agrees that such a process should be transparent, inclusive, coordinated with other initiatives and planned investments, flexible in the face of changing circumstances, and consistent with State energy policies.[4]

HECO's IGPR is a positive first step in achieving these outcomes and HPVC appreciates the effort that HECO undertook in consulting stakeholders during its development, as well as the emphasis HECO places on continued stakeholder engagement at multiple points in the planning

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1 Docket No. 2018-0165, Order No. 35569 at 25-26 (July 12, 2018) ("Order No. 35569").

2 *Id.* at 19.

3 *Id.*

4 *Id.* at 20.

process,[5] and incorporation of DERs into sourcing efforts through various channels.[6] However, HECO's presentation of the IGPR at the September 25 stakeholder workshop appears to reveal a process that looks very much like traditional integrated resource planning, commencing with competitive requests for offers ("RFOs") for utility-scale resources. There was less emphasis than HPVC had anticipated on distribution planning and the potential use of DERs to provide distribution-level services, including the use of tariffs, programs, and non-wires alternative ("NWA") opportunities, as reflected in the IGPR.

HECO seemingly views integrated grid planning as a variation on traditional "siloed" resource procurement, rather than true planning integration. It seems to retain a "top-down" character where utility-scale procurement occurs based on projections of customer needs, as opposed to a "bottom-up" or "customer-centric" process that seeks to modify needs at a more granular level to deliver system benefits. In other words, it continues the traditional mindset that customers are the cause of, rather than a potential solution to, system needs. As we look forward to a new integrated planning process, we must first prioritize opportunities for power system planning alignment at the resource, distribution and transmission domains. This ensures planning needs aligned across power system domains are not missed for optimization. As such, a coordinated bottom-up focus ensures that distribution and transmission grid needs are identified and able to be met and accounted for to ensure cost-effective resource solutions are identified within the planning process. Enabling customer DERs to align with the coincidental needs of the bulk power system creates a modern, flexible, and dynamic system. Such a planning coordination can deliver significant infrastructure and operational savings benefits, and result in not only more cost-effective resource deployment, but also the development of resource plans that enable Hawaii's residents to participate in our energy future.

While we hope we have misinterpreted HECO's intentions in this respect, it is our observation that similar approaches involving RFO-based sourcing of grid needs have to date been largely unsuccessful in matching DER-based solutions with grid needs or facilitating a transition to a more customer-centric approach to grid planning. This is has been true even of solicitations that targeted DERs. These comments discuss several foundational elements of integrated grid planning that are necessary to achieve a more customer-centric outcome, including:

- Allowing meaningful outside review and input into the planning process in all stages, from forecasting through needs identification and solution seeking.
- Emphasizing DER procurement methods such as tariff-based or programmatic approaches that prioritize standardization, simplicity, and consistency for both customers and DER providers to align with grid planning and operational needs.
- Prioritizing flexibility as it relates to avoiding stranded costs in the face of future uncertainties and the securing resources that can be actively adapted to serve differing end uses.

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[5] IGPR at 15.

[6] *Id.* at 14, Figure 3.

To assist the Commission's integrated resource planning efforts, we urge the Commission to consider lessons learned in other jurisdictions over the last several years, in particular California, which has expended considerable effort since 2014 on evolving distribution planning and integrating DERs into distribution planning and procurement regimes.

I. Rethinking the Utility-Centric Distribution Planning Process

As the Commission has observed, distribution planning in Hawaii has historically been an internal utility process.[7] In this respect, Hawaii is no different than virtually every other state and local jurisdiction. While utilities will continue to play a large role in distribution planning, it is critical to establish a planning process where decision-making is more independent.

A. *The Capital Investment Bias Issue*

The Commission is well aware of the regulatory and ratemaking challenges associated with capital investment bias on the part of utilities. HPVC does not believe it is tenable to maintain HECO as the primary decision-maker in distribution planning, given the clear conflict of interest it has with respect to pursuing traditional capital investments. This is not intended as a criticism of HECO or individuals involved in the distribution planning process; rather, this is an observation that placing HECO in the position of shaping the character of market opportunities for its direct competitors is not conducive to achieving a planning process that actively seeks to integrate DERs and other resources that are more cost effective than utility-owned assets. HECO has legitimate reasons to maintain the business model it knows and understands to the greatest degree possible. Moreover, even the best intentions cannot be expected to remove implicit biases and ingrained thinking from influencing how it conducts distribution planning. Such biases and mindsets can shape distribution planning in many forms, from the formulation of assumptions used in forecasts, to the identification of needs, to the selection of solutions to address those needs.

These concerns are not theoretical. In September 2018 the California Public Utilities Commission ("CPUC") adopted two Resolutions approving requests from Pacific Gas & Electric ("PG&E") and San Diego Gas & Electric ("SDG&E") to decline to enter any DER contracts with bidders into the utilities' respective Distribution Resource Plan ("DRP") Demonstration Project C ("Demo C") RFOs. DRP Demo C was intended to test and validate the ability of DERs to demonstrate locational net benefits, including deferral of distribution capital investments.[8] In both cases, the utilities stated that they had not received cost-effective offers from DER providers. While the CPUC accepted this, it noted that in both cases, additional operational

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[7] Order No. 35569 at 19; FN 54.

[8] Cal. Pub. Utils Comm'n, Docket No. R.14-08-013, *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge Including Deconsolidation of Certain Proceedings and a Different Consolidation of Other Proceedings* at 8 (Jan. 27, 2016) (stating "Project C: Demonstrate DER Locational Benefits. This project will validate the ability of DER to achieve net benefits consistent with the LBNA"). (LBNA refers to "locational net benefits analysis").

requirements *(i.e.,* an immediate availability requirement and much increased call and duration requirements) added by the utilities after the candidate projects and criteria had been approved by the CPUC likely contributed to the lack of cost-effective offers.[9] Consequently, the CPUC directed that future RFOs undergo additional outside vetting through the DRP Distribution Planning Advisory Group ("DPAG") and the CPUC Energy Division staff.[10] A reasonable person might conclude that these projects were designed to fail, or at best the utilities were indifferent to the outcome to the point of not making a meaningful effort to select viable candidate projects.

HPVC believes it is necessary for resource planning processes to evolve into a more collaborative effort with outside scrutiny at all stages to overcome both intentional and unintentional biases, simple indifference, and the perception of bias on the part of non-utility stakeholders. Persistent conflicts and disputes borne out of actual or perceived bias or indifference are not desirable for HECO or DER stakeholders; and removing HECO as the sole decision-making authority will help, rather than hinder, an evolution to a new resource planning regime.

Furthermore, integrated resource planning will benefit from a more collaborative process, in the form of increased opportunities to engage in creative problem solving, and ultimately, increased legitimacy of planning outcomes. In other words, in order to make a transition to a new planning paradigm, the planning process needs, and should, facilitate constructive outside input, ideas, and scrutiny of its planning. Our goal is to foster an environment where HECO wants to utilize DERs to their full capabilities to meet system needs, and we are committed to working with HECO to find solutions that facilitate that outcome.

For this purpose, we suggest that the Commission establish a review body similar to the California DPAG, which functions as an advisory body to the utilities on distribution planning, and includes an independent engineer and, critically, also allows for participation from market participants.[11] This type of collaborative approach should be accompanied by consideration of how performance-based regulation ("PBR") can assist in aligning utility incentives with such a

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[9] Cal. Pub. Utils Comm'n, Resolution E-4941 at 6-8 (Sept. 14, 2018) (pertaining to PG&E DRP Demo C).

[10] *See id.* at 8*; see also* Cal. Pub. Utils Comm'n Resolution E-4934 at 8-10 (Sept. 14, 2018) (pertaining to SDG&E DRP Demo C discussing DER operational requirements to meet deferral needs and stating "[t]o ensure that requirements vetted through DDOR or DPAG are the only ones included in future solicitations, SDG&E is ordered to share its RFOs with Energy Division 45 days prior to launch. Energy Division will review the RFOs to ensure that any new terms, not disclosed in DPAG, have not been included and will work with SDG&E to resolve any issues Energy Division identifies as problematic.").

[11] Cal. Pub. Utils Comm'n, D.16-12-036 at 44-45 (Dec. 22, 2016).

planning regime, though given the considerable work necessary to establish a PBR system[12]; PBR should not be a prerequisite to pursuing an evolution in distribution planning.

B. *The Distribution Planning Advisory Body*

The Commission has emphasized the need for transparency and inclusivity in the integrated planning process[13] and HECO's IGPR includes a Stakeholder Council, Technical Advisory Panel, and Working Groups.[14] While HVPC is encouraged by the multi-level stakeholder engagement plan HECO describes, the IGPR provides only a very high-level description that lacks many key details on how stakeholder engagement will function in practice. Below are several preliminary questions regarding stakeholder engagement and recommendations for addressing them.

How will members of the individual groups be selected?

All groups, whether they address strategic-level issues (*i.e.,* Stakeholder Council) or technical matters (*i.e.,* Technical Advisory Panel and Working Groups) should be open to market participants as well as other interested parties. To the extent that participation is limited to a specific number of people or groups, they should include representatives from a diverse set of stakeholders.

How will decision-making reflect input provided by stakeholder groups?

In order for an advisory body to be effective, it must have the ability to reach its own conclusions and recommendations independent of utility influence. This could take the form of reports on utility proposals with consensus or non-consensus recommendations for HECO and the Commission. This general report and recommendation protocol can be applied to all stakeholder engagement groups.

What individual working groups will be established?

HECO's IGPR only refers to three working groups, a market working group focused on revisions to the competitive bidding framework, a forecast assumptions working group, and a customer data access working group.[15] HPVC agrees that these working groups are appropriate, but we find the descriptions somewhat limiting and incomplete. For instance, there is no apparent mechanism for review and scrutiny of specific forecasted system needs and their potential for deferral with DERs or time-of-use programs, nor is there any reference to market working group activities including procurement mechanisms beyond competitive bidding. HPVC recommends

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12 *See, e.g.*, Docket No. 2018-0088, Order No. 35542 at 55 (setting a roughly 21-month timeframe to consider the evolution towards PBR in Hawaii).

13 Order No. 35569 at 20.

14 IGPR at 15.

15 *Id.* at 15-16.

that the forecast working group be reformulated as an all-encompassing *planning* working group whose review includes all aspects of integrated planning, similar to how the California DPAG is tasked with reviewing utility Grid Needs Assessments ("GNAs"), Distribution Deferral Opportunity Reports ("DDORs"), and the conduct of RFOs.[16] The market working group could be re-designated as a *procurement* working group that seeks to develop the details of all potential procurement methods.[17]

What information will be provided to stakeholders in different groups, and at what stage in different planning processes?

HECO's IGPR provides only the barest details of how and when working groups will be engaged and what information will be provided to them. As noted above in the context of the failed DRP Demo C projects in California, it is critical that any advisory groups be provided with complete information at all points in the planning process. This includes all relevant planning assumptions, data underlying those assumptions, the details of projects planned in response to system needs, and any parameters or operational requirements that may be established for RFOs or other tariffs and programs. In other words, they must possess all of the information HECO possesses if they are to make informed opinions and recommendations.

II. Promoting Viable DER Procurement Methods

A. *A Customer Friendly Procurement Regime*

HECO's IGPR suggests an emphasis on resource procurement via competitive bidding, despite some references to tariff-based or programmatic procurement regimes (e.g., the market working group appears to deal only with competitive bidding). This is concerning given that competitive bidding frameworks have not proven to be an effective mechanism of sourcing DERs. By nature, competitive RFOs are rigid, complex, and resource intensive, all of which tend to limit innovation. While competitive RFOs may be appropriate under some circumstances, *e.g.,* for large-scale projects with long-lead time and slow-developing needs, they are impractical for addressing needs of a smaller magnitude or with shorter timeframes given the level of effort and time required to conduct an RFO, evaluate bids, select projects, and build the resource. California has recognized this, albeit somewhat belatedly, revising the scope of its "Integrated DERs" rulemaking in February 2018 to incorporate consideration of alternative DER sourcing mechanisms (beyond RFOs), including the use of existing programs, incentives and tariffs.[18]

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[16] In California, the GNA defines specific anticipated distribution investment needs over a five year planning horizon, while the DDOR presents those needs that may be suitable for deferral using DERs.

[17] These California groups are focused on distribution planning; however, their structure and responsibilities can be applied equally to an integrated planning process.

[18] Cal. Pub. Utils Comm'n, Docket No. R.14-10-003, *Amended Scoping Memo of Assigned Commission and Joint Ruling With Administrative Law Judge* (Feb 12, 2018).

Competitive sourcing is not in and of itself a policy goal; it is only one potential mechanism for achieving cost-effective resource acquisition. Few, if any, customer-sited resources have historically been sourced through competitive processes, yet that does not mean that those same resources are or were not cost-effective, or that competitive sourcing would have resulted in a more cost-effective outcome. For instance, customers do not "bid" the amount of incentive that they would require to make an investment in a more energy efficient appliance for the obvious reason that such bidding would be complicated and impractical, and compromise program enrollment and the accompanying benefits achieved by the program.

As with energy efficient appliances, customers make investments in DERs for myriad reasons, and DERs can provide substantial grid benefits. For DERs, the key question to ask is how to leverage those investments by encouraging the most grid-friendly behavior when such behavior may not otherwise be in the customer's interest. This approach is at its core a simple balancing of the right price signal for encouraging as many customers as possible to operate their systems in response to grid needs and the cost of that price signal relative to traditional grid investments and operations.

There is no driving need for "competition" except that which takes place between the DERs and traditional investments in the cost-benefit analysis outlined above. Under such a regime, as long as the proper balance has been struck between costs and benefits, the resources are by nature cost-effective and ratepayers are better off than they would otherwise be. In the context of customer-sited resources, an emphasis on competitive bidding is equivalent to making a highly uncertain "perfect" outcome the enemy of many readily achievable good outcomes.

B. *DER Procurement Via Standardized Regimes*

The procurement of cost-effective customer-sited energy efficiency resources has a long history of producing net benefits for ratepayers via standardized programmatic regimes such as rebate programs. Likewise, standardized tariffs such as net metering and standard offer contracts for qualifying facilities under PURPA have resulted in the successful deployment of thousands of MW of customer-sited and grid supply renewable energy generation, clearly demonstrating that standardized tariffs are a highly effective deployment mechanism.

Such standardized procurement or deployment mechanisms have now been extended to operationally flexible DERs in a number states, including programs that target strategic locations, distribution deferral, "duck curve" issues, or more generalized grid services, including:

- New York – Dynamic Load Management ("DLM") Tariffs: The DLM tariffs procure demand response resources based on a fixed capacity reservation payment and performance incentive model. The payment levels differ by utility based on marginal costs, such that each utility has a system-wide Commercial System Relief Program and a Distribution Load Relief Program that targets locations with high marginal distribution costs, but the mechanism for procuring the service is uniform.[19]

[19] *See, e.g.*, Consolidated Edison ("ConEd") Rider T – Commercial Demand Response Programs.

- New York – Value of DERs ("VDER") Tariff: The VDER tariff is New York's successor tariff to net metering, currently deployed only for non-residential DERs. The VDER Tariff compensates DER customers for exports to the grid at a value-based rate that includes, among other values, a utility-wide Demand Reduction Value that may be fixed for three years, and a Local System Relief Value for defined geographic areas that may be fixed for ten years.[20]
- New York – Brooklyn Queens Demand Management ("BQDM") Program: The BQDM program targets eliminating the need for a large (more than $1 billion) distribution capital investment project utilizing a combination of alternative wires investments, grid-scale storage, demand reduction measures, and combined heat and power. The demand reduction portion initially utilized a combination of fixed incentives for battery storage and other demand side resources, but later also piloted a simple annual auction process with standardized terms and operational requirements.[21]
- California – CAISO Load Shift Product: In September 2018 the CAISO Board adopted a proposal from its Energy Storage and DERs Phase 3 Initiative to establish a Load Shift Product that provides behind the meter storage systems with a standardized way to bid consumption or curtailment into the CAISO energy market. The structure is based on the CAISO's existing Proxy Demand Response ("PDR") market product, and effectively amounts to bi-directional demand response, designed in part to help mitigate periods of over-generation from renewables on the CAISO system.[22]
- New England – ISO-New England ("ISO-NE") Demand Resources: The ISO-NE allows both active (*i.e.,* dispatchable) and passive demand resources (*e.g.*, behind the meter solar) to qualify for participation in the Forward Capacity Market ("FCM"). The passive demand resource category is composed of on-peak demand resources and seasonal peak demand resources, which differ based on how the peak period is defined.[23] Behind the meter solar facilities paired with storage have multiple participation options, including as a single passive demand resource, two separate passive demand resources, or separately

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[20] New York Pub. Serv. Comm'n, Docket No. 15-E-0751, *Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters* at 118 (Mar. 9, 2017).

[21] New York Pub. Serv. Comm'n, Docket No. 14-E-0302, *ConEd 2018 BQDM Implementation and Outreach Plan* (Jan. 29, 2018).

[22] For relevant materials, *see* CAISO Energy Storage and Distributed Energy Resources, *available at* http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResources.aspx.

[23] *See* ISO-NE, About Demand Resources, *available at* https://www.iso-ne.com/markets-operations/markets/demand-resources/about.

with solar as a distinct passive demand resource and the battery storage as a distinct active demand resource.[24]

It is not our intent to suggest that any one of these models is necessarily a perfect fit for Hawaii, but instead to offer these examples for further exploration by the Commission as they all have features that might be adapted to suit Hawaii's unique needs. In all of the examples described above, the program or tariff operates in conjunction with a customer's otherwise applicable retail rate, making it much more accessible to customer-sited DER participants than an RFO.

C. *Standardized Programs in Hawaii*

HPVC urges to the Commission and HECO to seek the development of standardized tariffs or programs for the procurement of customer-sited DERs. On a conceptual level, HPVC envisions a standard contract or standard offer tariff, through which a DER customer can be enrolled without requiring bidding, negotiation, or other administrative burdens associated with traditional RFO-based procurement mechanisms. The tariff or contract would contain a set of standardized terms and conditions (e.g., insurance) already approved by the Commission. Other factors could vary based on the nature of the need. For instance, a distribution deferral contract could feature a series of standard inputs such as:

- Value of the grid service provided, established by either an avoided traditional wires solution or a per MWh or MW estimate of the avoided cost.
- Size, *i.e.,* the amount of DERs or the magnitude of service required.
- Timing, *i.e.*, frequency and duration of the service required.
- Location, *i.e.*, where on the grid the services are needed.
- Term, *i.e.*, a minimum amount of time that the service will be needed (to allow for investments to be made) but after which the utility may terminate the agreement.

Those variables would be populated consistent with the specific need according to a well-defined methodology with a basis in utility planning. The result is a standard offer (*i.e.*, rider tariff) layered on top of the applicable tariff and rate option governing the customer and the DER asset (*i.e.*, CSS, CGS+, Smart Export, NEM or CSS).

This type of mechanism is well-suited for addressing typical system and locational needs, and could be easily deployed to serve system needs that were not anticipated to arise well in advance. In addition, such a common, durable framework would place DER providers in a better position to meet those needs, allowing them to develop consistent strategies for customer engagement and participation even if some aspects of a given deferral opportunity will be different than others. Finally, the design recognizes and takes advantage of the fact that DERs can be deployed

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[24] ISO-NE, *Forward Capacity Market (FCM) Qualification Examples for Storage Technologies* (March 2018) *available at* https://www.iso-ne.com/static-assets/documents/2016/03/fcm_qualification_examples_for_storage_technology_final.pdf.

incrementally, and that incremental additions have value both in the form of actual deferral and avoidance of the risks associated with "lumpy" investments that carry the potential for stranded costs. For instance, distribution planning may indicate a need of three MW of dispatchable DERs within three years in a local area. A program might initially target one MW of DER deployment in each year, but the projected need and program offer could be refined in successive planning cycles to avoid over- or under-procurement.

III. Seeking a Flexible Future System

A. *The Merits of a Flexible System*

One of the most prominent advantages DERs have over traditional infrastructure investments is that they can flexibly serve multiple grid needs, more so when they are located at the lowest level of the system (*i.e.*, the customer domain). Whereas most distribution investments serve only a single purpose (*e.g.*, transporting electricity, providing voltage support), a DER can dynamically change operations between different modes of operation to provide different services at different times. This flexibility attribute is highly valuable in the context of changing system needs and uncertainties. For instance, a DER providing distribution capacity support for a period of five years may later be re-purposed to provide system-level load consumption capacity or peaking capacity services, whereas an equivalent distribution capacity solution such as a transformer upgrade may become underutilized with no other apparent useful function if load increase projections fail to materialize, *i.e.,* become a stranded cost. Moreover, DERs are capable of providing multiple services from the same capacity concurrently or within different time intervals within a short time frame (*i.e.,* hour to hour). DER procurement to defer traditional utility investments has been argued against in some forums on the basis that uncertainty exists in future system needs; however, flexible DERs should be procured to the greatest extent possible *precisely because* uncertainty exists in future system needs.

Moreover, this flexibility is likely to become more valuable in the future. However, the ability to take advantage of the full range of flexibility of DERs will be compromised if uncertainty persists regarding whether some of these capabilities, or some categories of DERs (*e.g.,* legacy net metered systems) will be excluded or otherwise restricted from participation in future programs. We urge HECO and the Commission to establish a firm policy that planning should support the maximum degree of system flexibility and seek to utilize the *full capabilities of all DERs* to provide incremental grid services. This means that market participation options should be technology agnostic with parameters that reflect the need in question as opposed to artificial limits (*e.g.,* arbitrary prohibitions of exporting power).

Such a policy has precedent. For instance, it has become a feature of California's efforts to establish a framework for DERs to provide distribution services.[25] Likewise, albeit to this point

[25] Cal. Pub. Utils Comm'n, Resolution E-4889 at Ordering Paragraph 15 (Dec. 14, 2017) (stating "[t]he Utilities shall not categorically exclude or prohibit behind-the-meter solutions that export energy to the grid from participating in the solicitation process").

in a more piecemeal manner, New York has adopted changes to individual utility tariffs to eliminate pre-existing restrictions that prevent DERs from being used to their full potential.[26]

B. *Implementing the Concept of Incrementality*

HPVC is aware that our recommendation for "universal" DER eligibility for the provision of grid services may generate concerns over the potential for double payment or compensation for the same service via multiple channels. HPVC recognizes that concerns of this type are legitimate and must be addressed through a policy that establishes a prohibition against double compensation and the meaning of "incrementality." We point to how California has addressed the issue as a good starting point. In implementing its own distribution deferral pilots, the CPUC established that:

- Incremental services include those providing additional value via "altered operations and/or the installation of enhancements to equipment";[27]
- "[A] DER is eligible to provide multiple incremental services and be compensated for each service"; and
- "[S]ervices offered by existing DERs that are above and beyond what is expected under other programs should be considered incremental."[28]

These descriptions are consistent with our position that DERs and DER operation of all types should be universally eligible to provide grid services as a default policy, and that compensation should be provided in all instances where the modification of a DER system or its operations results in the provision of a grid service that has value. While it is clear that further discussions will be necessary to translate such a principle to practical application, we recommend that the principle of incrementality itself be established as a foundation in order to facilitate those future discussions.

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[26] New York Pub. Serv. Comm'n., Docket No. 17-E-0104, *Order Approving Subject to Modifications Tariff Amendment for Battery Discharge in Brooklyn/Queens Demand Management Program and Making Other Findings* (May 18, 2017) (approving tariff revision to allow exports to the secondary distribution system from battery storage systems participating in the ConEd BQDM program and NWA RFOs, and directing ConEd and other utilities to evaluate and report on the reasonableness of eliminating battery storage export restrictions in their DLM programs).

[27] Cal. Pub. Utils Comm'n, Resolution E-4889 at Finding 8 (Dec. 14, 2017) (stating "Incremental services are those distinct services offered by a DER under one program or tariff that provide additional value, via altered operations and/or the installation of enhancements to equipment, beyond that expected or required to be provided under another program or tariff to which the DER may subscribe.").

[28] *Id.* at 27.

IV. Conclusion

Despite the concerns raised in these comments, HPVC emphasizes that we are encouraged by the general path that HECO plots in its IGPR. We understand that it would have likely been impossible for HECO to fully develop all of the details of an integrated grid planning vision in one fell swoop. We hope that our concerns stem from a simple misunderstanding of HECO's vision, attributable to the relatively early stage of what is bound to be a long effort. We also hope that the requests we have made for greater clarity and related recommendations, in particular the finer details of how outside advisory input will operate, are helpful to HECO and the Commission.

Above all, we wish to emphasize that our goal is to work collaboratively with HECO to evolve planning processes, and related matters such as utility incentives and disincentives, in such a way that benefits HECO, DER providers, and most importantly, all ratepayers. We are confident that such an outcome is possible and look forward to the (considerable) work ahead to make it a reality.

Respectfully submitted,

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I hereby certify that on this date, a copy of the foregoing document, together with this Certificate of Service, were duly served upon the following individual(s) by having said copies delivered by mailing a copy by U.S. mail, postage prepaid, as follows:

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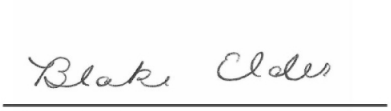
DATED: Cary, North Carolina, October 15, 2018.



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