BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAI'I

FILED

2015 JAN 20 A 9:20

------ In The Matter Of -----	)	
	)	
PUBLIC UTILITIES COMMISSION	)	DOCKET NO. 2014-0192
	)	
Instituting a Proceeding to Investigate Distributed Energy Resource Policies	)	
	)	

PUBLIC UTILITIES COMMISSION

HAWAIIAN ELECTRIC COMPANIES' MOTION FOR APPROVAL OF NEM PROGRAM MODIFICATION AND ESTABLISHMENT OF TRANSITIONAL DISTRIBUTED GENERATION PROGRAM TARIFF

APPENDICES 1 TO 5

AND

CERTIFICATE OF SERVICE

BRENDAN BAILEY, ESQ.
Hawaiian Electric Company, Inc.
P.O. Box 2750
Honolulu, Hawai'i 96840-0001

ROD S. AOKI, ESQ.
951 Mariners Island Boulevard
Suite 300
San Mateo, CA 94404

Attorneys for
HAWAIIAN ELECTRIC COMPANY, INC.
MAUI ELECTRIC COMPANY, LIMITED
HAWAI'I ELECTRIC LIGHT COMPANY, INC.

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAI'I

------ In The Matter Of -----	)	
	)	
PUBLIC UTILITIES COMMISSION	)	DOCKET NO. 2014-0192
	)	
Instituting a Proceeding to Investigate Distributed Energy Resource Policies	)	

HAWAIIAN ELECTRIC COMPANIES' MOTION FOR APPROVAL OF NEM PROGRAM MODIFICATION AND ESTABLISHMENT OF TRANSITIONAL DISTRIBUTED GENERATION PROGRAM

HAWAIIAN ELECTRIC COMPANY, INC. ("Hawaiian Electric"), MAUI ELECTRIC COMPANY, LIMITED ("Maui Electric") and HAWAI'I ELECTRIC LIGHT COMPANY, INC. ("Hawai'i Electric Light") (collectively "Hawaiian Electric Companies" or "Companies") are committed to increasing distributed generation on their systems as part of an overall effort to aggressively move toward a more cost-effective, balanced and diversified portfolio of renewable energy resources, achieve a sustainable and reliable energy future and provide expanded customer options and benefits to all customers. In order to accomplish these goals, the Hawaiian Electric Companies respectfully move the Honorable Public Utilities Commission of the State of Hawai'i (the "Commission") as follows:

Summary of This Filing

- State policies have been very successful in increasing the amount of distributed renewable rooftop photovoltaic systems in Hawai'i ("DG"). Together with investments made by our customers, these policies have made Hawai'i a global leader in DG integration -- far exceeding any other utility in the nation. As of the end of 2014, over 51,000 systems have been installed, almost 11,000 in 2014 alone, representing 390 total MW of capacity and 12% of residential customers.

This DG is a significant contributor to the Hawaiian Electric Companies' progress in meeting the State's renewable portfolio standard.

- The growth in DG has benefitted many: customers, with lowered bills, increased choices, and control over their energy use; the business community, through jobs in a fast-growing energy industry in Hawai'i; and our community and State as a whole, with more renewable energy that supports our collective efforts to reduce Hawai'i's dependence on imported oil and achieve our environmental goals.

- The next step in the Companies' overall DG plan begins with a clear pledge to honor commitments made to existing Net Energy Metering ("NEM") program customers, and to those who have already applied to participate in the existing NEM program.

- Furthermore, based on the results of technical inverter testing performed in partnership with the National Renewable Energy Laboratories, the Electric Power Research Institute and Solar City, the Companies plan to increase the circuit penetration threshold for transient overvoltage on their systems from 120% of Gross Daytime Minimum Load ("GDML") to 250% of GDML. This will allow additional DG interconnection while the Companies continuously monitor both circuit and system-level impacts to maintain reliability and safety and to determine whether further expansion of penetration thresholds is prudent.

- However, the unprecedented DG growth has also created economic, technical and equity issues that must be addressed. The 283 MW of DG on Oahu as of December 31, 2014 represents approximately a quarter of Hawaiian Electric's 2014 total system peak load. Unlike Hawaiian Electric's traditional generating plants and larger solar and wind resources, the vast majority of this intermittent DG is not controllable by the Companies. In order to maintain the reliability and safety of the electrical system for all of the Companies' customers, including DG customers, and to achieve the Companies' goal of tripling the amount of DG on their systems by 2030, an evolution to a new, more equitable and sustainable tariff structure, which can take advantage of more advanced technical capabilities, and which protects all customers against cross-subsidization, is required.

- The proposed new tariff structure will directly address the cost transfer presently occurring under the existing NEM program, which compensates customers for energy exported onto the grid by DG systems at full retail rates, allows DG customers to shift the responsibility of contributing to the cost of operating the grid to full-service customers (customers that rely solely on the utility to meet their energy needs), while still allowing NEM customers to rely on and benefit from access to the grid for import and export of power. This results in many NEM customers paying less than non-NEM customers for services that they receive from the utility. At the end of 2014, this annual cost transfer from DG to full-service customers totaled approximately $53 million compared with $38 million at the end of 2013, and will increasingly affect customer bills in the near future as DG capacity continues to grow. It is the Companies' position that this level of cost transfer is inequitable and unsustainable for the Companies' non-NEM customers (the approximately 88% of customers that do not have NEM systems), and must be affirmatively addressed at this time. Addressing this situation will require a transition to a new DG program.

- The grid's capacity to accept excess energy from DG systems is not infinite. The export of excess solar energy to the grid from DG creates significant operational challenges for the Companies. High levels of uncontrolled, unscheduled, and variable energy from DG systems are an increasing threat to the safety and reliability of the power network at the circuit and system levels. As explained in the Companies' Power Supply Improvement Plans filed last year, the Companies are currently experiencing, and working to resolve, reliability issues caused, in part, by unprecedented levels of interconnected DG. However, recognizing that DG is a valued option to customers, the Companies will resolve the reliability issues in parallel with expanding room for additional DG through a new DG program.

- Hawaiian Electric is currently implementing several pilots with multiple local and national PV and storage vendors in Hawai'i to provide concrete, real-world performance data and operating experience on the ability to manage load using PV-only, battery-only and PV/battery combined systems. These investigative pilots, which the Companies anticipate could reach as many as 1,000 total projects, are intended to characterize and quantify the benefits that these types of systems can provide with the aim of accelerating the use of distributed storage systems on the customer side of the meter to support localized circuit-level and system-level needs.

- By providing this program to both lower costs and secure a future where all resources contribute to grid stability, capabilities which the Companies are not able to require under the existing NEM program, the Companies will be better able to address technical, as well as economic and equity issues, going forward.

- This program evolution is consistent with State policy, which always envisioned reasonable limits upon the existing NEM program. As one example, based upon these limits, the Kaua'i Island Utility Cooperative has suspended its NEM program. Similarly, the Companies have proposed that when proposed NEM program capacity is met, or within 60 days of the date of this filing, whichever comes first, all **new** NEM program applicants will be directed to the Companies' new DG tariff. This evolution is also consistent with the Companies' Distributed Generation Interconnection Plan filed on August 26, 2014.

- Consistent with the Companies' goals of: (1) lowering customer costs by 20%; (2) tripling the amount of DG on our island systems in a safe and reliable manner; (3) providing customers with more options to help control their energy costs; and (4) protecting the interests of all customers, the Companies believe that a more equitable and more sustainable DG program is required. Therefore, the Companies propose the following:
    - Honor the rights of existing NEM customers and those NEM customers who have been approved for interconnection. These customers' agreements will not be affected by this Motion
    - Reinstitute a program capacity amount for the Companies' existing NEM program consistent with the Commission's statutory authority. This amount would be set high enough to enable those customers whose NEM applications are presently undergoing a review for interconnection the opportunity to interconnect their systems under the existing NEM program. This amount would also include an additional margin to account for some amount of new NEM applications that may be received while this Motion is being considered. These customers may also choose to move to an alternative program such as the community solar or non-export/smart export program options currently under development by the Companies when such programs become available.
    - Approve a proposed new Transitional Distributed Generation ("TDG") tariff to be made available to customers seeking interconnection after the NEM program capacity (or the requested timeframe for decision on this request) is reached. The TDG more fairly allocates fixed grid costs to DG customers and credits customers for the value of excess energy produced by their systems. The TDG would function similarly to the existing NEM program in that there would be a monthly rollover of credits with a 12-month reconciliation period.
    - Approve a new standard form TDG contract to be utilized for those customers seeking to participate in the TDG, which will allow for the advanced technical capabilities required to integrate higher levels of distributed generation, including utilization of the grid support functionality embedded in advanced inverters, and the enabling of two-way communications with customer-sited DG.

- Reinstate the Companies' ability to submit proposed modifications to Tariff Rule 14H via a 30-day filing rather than by Application in order to facilitate timely responses to rapid changes in the DG environment and to allow necessary modifications that facilitate the integration of distributed generation to the Companies' systems to be adopted more quickly.

- Once these program modifications are approved, as noted, it is anticipated that the Companies will be able to increase the circuit penetration threshold for transient overvoltage on their systems from 120% of Gross Daytime Minimum Load ("GDML") to 250% of GDML. This will include continuous monitoring of both circuit and system-level impacts to maintain reliability and safety, and to determine whether further expansion of penetration thresholds is prudent.

- To facilitate the safe and reliable interconnection of these higher amounts of DG, the Companies will also make strategic and cost effective capital investments to upgrade the Companies' circuits to support the increased thresholds and corresponding higher integration levels of renewable energy. This will include collaboration with stakeholders to identify circuits with the highest demand or which provide the greatest benefits to the system. The Companies propose that these costs be treated as grid improvements that benefit all customers instead of charging costs only to those installing DG systems on the circuit.

Accordingly, the Hawaiian Electric Companies respectfully move the Commission for approval of: (1) reinstitution of an appropriate program capacity for the Companies' existing NEM program; (2) the Companies' proposal to address both existing NEM program participants and those customers presently awaiting interconnection approval under the existing NEM program as a part of this transition process; (3) a proposed interim TDG tariff to be made available to customers seeking interconnection after the NEM program capacity is reached (and until a further revised distributed generation procurement mechanism ("DG 2.0") can be developed with stakeholders and approved in this proceeding); (4) the standard form TDG contract to be utilized for those customers seeking to participate in the TDG; (5) reinstatement of the

Companies' ability to submit proposed modifications to Tariff Rule 14H via a 30-day filing pursuant to Rule 6-61-111 of the Commission's Rules of Practice and Procedure, Title 6, Chapter 61, Hawai'i Administrative Rules ("HAR") rather than a full Application as directed through Order No. 30027, Ordering Paragraph 6, issued December 20, 2011 in Docket No. 2010-0015; and (6) such other and further relief as the Commission may deem appropriate under the circumstances discussed herein.

The Hawaiian Electric Companies respectfully submit that this Motion, the supporting documentation provided or referenced herein, any comments provided by the parties to this proceeding, and any reply which may be authorized by the Commission, will provide a sufficient record for the Commission's decision making on the requests made in this Motion. However, to the extent that the Commission may determine that additional process or information is required prior to decision making, the Companies stand ready to actively participate in such process as necessary.

<u>Due to the ever more critical nature of these issues - and in particular the unconstrained growth under the current NEM program and its associated economic, technical and equity impacts, the Companies respectfully request that any Commission order on the requests presented in this Motion be issued on an expedited basis, within sixty days from the date of this filing (or by March 20, 2015) so that these program modifications and elements can be made available to customers as soon as possible</u>.

A hearing on this Motion is not requested. To the extent that any comments are submitted pursuant to H.A.R. 6-61-41 in response to this Motion, the Companies respectfully request the Commission's authorization to file a reply within 10 days of the receipt of such comments for purposes of supplementing the available record for the Commission's decision making.

The Companies bring this motion pursuant to Hawai'i Administrative Rules Section 6-61-41, and Hawai'i Revised Statutes ("HRS") Sections 269-102-104, and 269-16.

I. INTRODUCTION AND OVERVIEW

Achieving a More Cost-Effective, Advanced and Diversified Renewables Portfolio

On April 28, 2014 in Docket No. 2012-0036, the Commission issued Order No. 32052. Attached as Exhibit A to Order No. 32052 were the Commission's Inclinations on the Future of Hawaii's Electric Utilities ("Exhibit A"). Through Exhibit A, the Commission provided its "perspectives on the vision, business strategies and regulatory policy changes required to align the HECO Companies' business model with customers' interests and the state's public policy goals." (Id. at 1)

Among these were perspectives and guidance regarding how the utilities should plan for and work to integrate higher levels of cost-effective renewable resources to their systems. In particular, the Commission emphasized: (1) development of a more sustainable business model and balanced and diversified portfolio of renewable resources; (2) the need for the utilities to make strategic capital investments which provide long-term customer value, and Commission support for efforts to cost-effectively enable the integration of renewables; (3) the objectives of lower, more stable electric bills and expanding customer energy options, while maintaining reliable energy service in a rapidly changing system operating environment; (4) the need to develop modern, advanced electrical networks that are capable of integrating greater quantities of customer-sited distributed energy resources ("DER") – including utilization of the grid support functionality embedded in advanced inverters, the enabling of two-way communications with customer-sited DER to enable real-time monitoring and active utility management, and a future where all generation resources contribute to maintaining system stability; and (5) the need for changes to existing electric utility regulatory policy and rate structures to achieve Hawaii's clean energy future. (Passim.)

Consistent with these observations and guidance, and the commitments made through the Companies' Power Supply Improvement Plans and Distributed Generation Interconnection Plan submitted on August 26, 2014, the Companies are actively pursuing a number of initiatives in parallel to achieve the broad goals outlined by the Commission. With regard specifically to the issue of the integration of a more diverse and cost effective portfolio of renewable resources and in particular higher levels of distributed renewable resources in a sustainable manner, the Companies have evaluated and identified the following substantive steps which can be initiated as a part of a comprehensive program which balances both technical and economic issues in the best interests of all customers:

1. As discussed more fully herein and in Appendix 1, through a collaboration with SolarCity and the Electric Power Research Institute a number of inverters were tested at the National Renewable Energy Laboratory in Golden, Colorado. The performance of each selected inverter was tested under controlled conditions to determine the extent to which overvoltage occurred and the speed at which inverters tripped off line when test circuits were suddenly islanded. Upon consideration of the test results, the

factors enumerated in Appendix 1, mitigation measures that have been identified, and ultimately the Companies' ability to maintain the reliability and safety of the electric system which is paramount, the Companies have concluded that it will be possible to increase the allowable circuit penetration threshold for transient overvoltage on their systems from 120% of Gross Daytime Minimum Load ("GDML") to 250% of GDML. In order to maintain both reliability and safety, the Companies will monitor circuits to verify expected performance through operational data. Information collected to date indicates that transient overvoltage can be managed; however integration of distributed generation projects may require mitigation measures and modifications to generation facilities, circuits or the power system. These issues are identified through review of each application pursuant to the Companies' Rule 14H and evaluation as necessary to help assure that no significant and adverse circuit or system issues would occur as a result of interconnection. The evaluation includes examination of local circuit level impacts, area network, and system level impacts from the interconnection. Data secured from these monitoring processes will inform the Companies' future policies which could include further expansion of penetration thresholds where warranted.

2. The Companies will make strategic and cost effective capital investments to upgrade the Companies' circuits to integrate the higher amount of solar resulting from increased thresholds and corresponding higher levels of renewable energy and rate base those costs to provide long-term value to all customers.

As the Commission has discussed, to achieve this more cost-effective, diverse, and advanced renewable energy future where all resources contribute to maintaining the stability of the grid, changes to existing policies and structures will be required as well.

Consistent with ongoing requirements of projects seeking to interconnect to the Companies' systems:

(a) The system to be interconnected must use inverters that have been tested for transient overvoltage to the satisfaction of the Hawaiian Electric Companies or certify compliance of performance using a Company-approved test plan; and

(b) The system to be interconnected must comply with identified voltage and frequency ride-through requirements, and other required settings applicable and certified at the time of installation.

Additionally, stakeholders in various Commission proceedings are presently discussing the availability of a variety of advanced functionalities, including in particular control functionality, which may be required of interconnecting systems in the future upon receipt of any necessary Commission approvals. These types of advanced capabilities and overall support of grid stability can be discussed as bases for prioritization of resource interconnection in the future.

More immediately, in order to achieve the objectives discussed above and set forth through Exhibit A, and to be able to expand penetration limits in a cohesive and comprehensive manner, a transition away from existing programs which are not consistent with a more cost-effective, balanced, diverse and advanced energy future is required. In particular, a transition from the existing NEM program to an interim and transitional distributed generation tariff will be required as a first step toward achieving these goals.

<u>Program Transition to Achieve a More Cost-Effective, Diverse and Grid Supportive Portfolio of Resources</u>

The Companies' NEM programs have succeeded in incentivizing customers to invest in distributed, renewable, solar photovoltaic systems. As of December 31, 2014, the total number of DG systems interconnected on the Companies' grids was approximately 51,000, with a total capacity of about 390 MW. Of those installations, over 97% took advantage of the NEM program. With approximately 36,400 DG systems and 283 MW on O'ahu as of December 31, 2014, 13% of Hawaiian Electric's residential customers now have rooftop solar, an appreciably higher percentage than any mainland utility.

This is not unexpected. The State of Hawai'i expressly enacted NEM program provisions to encourage the establishment of a market for renewable energy in Hawaii. In combination with federal and state incentives, the legislation served to nurture a developing technology and industry, at a time when the cost to self-generate clean renewable energy was prohibitive. This has changed. PV system costs have decreased dramatically during the last several years and the need to provide retail compensation to incent distributed generation no longer exists.

Moreover, the unrestrained continuation of incentive programs can produce unintended and undesired consequences. In the case of the existing NEM program, the unique provisions designed to entice investments in smaller, distributed renewable resources have resulted in a situation where <u>NEM systems are in aggregate the largest by far, and generally the most costly, of the Companies' renewable energy resources</u>. NEM customers utilize the power grid to provide energy when their onsite power is not available. Yet, <u>revenues from these resources do not recover a fair share of the fixed costs associated with maintaining the utility grid, which results in a shift of those costs to</u>

other non-NEM customers, and the total size of the program results in the displacement of other more cost-effective, diverse and grid-friendly renewable resources. NEM systems therefore increase costs for non-participants while simultaneously reducing the potential to utilize alternate resources to reduce costs. In short, the NEM program has reached the point where it is no longer sustainable in its current form.

Indeed, the Commission recently stated its belief that "*it is unrealistic to expect that the high growth in distributed solar PV capacity additions experienced in the 2010 - 2013 time period can be sustained, in the same technical, economic and policy manner in which it occurred, particularly when electric energy usage is declining, distribution circuit penetration levels are increasing, system level challenges are emerging and grid fixed costs are increasingly being shifted to non-solar PV customers*. (Order No. 32053 at 49) The Commission also observed that the distributed solar business model "*will need to shift from a customer-value proposition predicated upon customers avoiding the grid financially - but relying upon it physically and thereby creating circuit and system technical challenges - to a new model where the customer-value proposition is predicated upon* ***how distributed solar PV benefits both individual customers and the overall electric system*** *....*" (Id. at 49-50)(Emphasis supplied)

The State provided the Commission with the authority to accomplish such a shift by empowering the Commission to modify or conclude the NEM program in three ways. First, the legislation provided for a program capacity equivalent to 0.5 percent of the electric utility's system peak demand. It also provided the Commission with the discretion to "*modify, by rule or order, the total rated generating capacity produced by eligible customer-generators ....*" Second, the Commission was provided with the authority to "*evaluate, on an island-by-island basis, the applicability of the generating capacity requirements of this subsection and, in its discretion, may exempt an island or a utility grid system from the generating capacity requirements.*" And third, the Commission was provided with the authority to determine that an electric utility is no longer obligated to provide net energy metering to customer generators in its service area based upon the total rated generating capacity produced by eligible customer-generators of the utility in the utility's service area. (See, Section II.C.3 below)

Through this Motion, the Companies provide their proposal for a fair and reasonable transition to a more sustainable distributed renewable energy procurement program, described in the Companies' Distributed Generation Interconnection Plan ("DGIP") as "DG 2.0".[1] This transition will allow all customers to receive the benefits of more cost-effective and grid friendly distributed renewable resources and will affirmatively address in a positive fashion certain provisions of the existing NEM program which result in less than fair allocation of costs to customers. The transition, once approved, will ensure that the existing cost, technical and equity issues that are a part of the existing NEM program are not continued into perpetuity and will clear the way for the expansion of circuit penetration limits and the strategic and effective investment in infrastructure discussed above and consistent with the integration of more cost-effective, diverse, and advanced renewable resources necessary for a robust and sustainable energy future.

[1] The Companies' DGIP was filed on August 26, 2014 in Docket No. 2011-0206 in compliance with Order No. 32053 issued by the Hawai'i Public Utilities Commission on April 28, 2014. The DGIP has been transferred to this docket for review, pursuant to Order No. 32292 issued September 12, 2014 in Docket No. 2011-0206.

The transition will begin with the reinstitution of a NEM program capacity level consistent with the Commission's statutory authority. The Companies propose that this capacity be set at percentage figures for each island system which reflect and include existing interconnected NEM customers, those NEM customers that have been approved for interconnection, those customers whose NEM applications are presently undergoing a review for interconnection, and an additional margin to account for some amount of new NEM applications that may be received during the requested timeframe for Commission action on this Motion.

To the extent that customers that fall within this extended program capacity are not able to or not allowed to interconnect for technical reasons, or decide on a voluntary basis to no longer participate in the NEM program (including moving to an alternative program such as the community solar or non-export/smart export program options currently under development), the percentages, which will be based on each island's system peak at the time of the filing of this Motion, will be reduced in a corresponding fashion. This is consistent with the goal of transitioning customers to DG 2.0 rather than allowing them to continue to subscribe to the existing NEM program. The Companies respectfully submit that once these new program capacity limits are met, or by March 20, 2015 (the Companies' requested expedited sixty-day approval date for approval of this Motion), whichever occurs first, the Commission should determine that the Companies are no longer obligated to provide net energy metering to customer generators in their service areas and the NEM program should be declared closed.

With the reintroduction of an appropriate NEM program capacity, alternative and more sustainable program options should be made available to customers whose proposed generation is in excess of the NEM program capacity approved by the Commission. The Companies propose that the Transitional Distributed Generation Program tariff described in more detail below be made available to customers on an interim basis until DG 2.0 can be developed with stakeholders and approved in this proceeding, or until January 1, 2017, whichever occurs sooner.

The TDG alternative, a copy of which is attached to this Motion as Appendix 2, encompasses reform of the rates governing DG interconnections and proposes a tariff structure for dispatchable DG systems that more fairly allocates fixed grid costs to DG customers and credits customers for the value of their excess energy. The TDG would function similarly to the existing NEM program in that there would be a monthly rollover of credits with a 12-month reconciliation period for energy exported to the grid. The credit to be applied would be equal to the Base Fuel Energy Charge plus the Energy Cost Adjustment ("ECA") rate – which during the month of January 2015, is 14.6712¢/kWh for O'ahu, 18.6177¢/kWh for Hawai'i island, 22.2996¢/kWh for Maui, 27.5688¢ for Lana'i and 26.2058¢ for Moloka'i.[2]

The advantage of this rate is that it is allows for a <u>more equitable and cost-effective procurement of distributed renewable energy</u>. It is also easier for customers to understand as it is more consistent with a kWh bill credit, and is consistent with the Commission's stated inclination toward the unbundling of rates. Furthermore, it clearly delineates between energy delivered and received, and fixed and non-fixed charges; and provides for a positive investment return period similar to mainland jurisdictions. It is important to clarify here that TDG customers would not have the right to any retroactive

[2] Hawaiian Electric (Attachment 8), Hawai'i Electric Light (Attachment 10) and Maui Electric (Attachments 7, 15 and 22) Energy Cost Adjustment Factor for January 2015, filed December 29, 2014.

higher rates once DG 2.0 is approved and likewise the Companies would not be entitled to seek any refunds if approved DG 2.0 rates are lower than TDG rates.

In order to accommodate the new provisions associated with the TDG, a new standard form contract, a copy of which is attached to this Motion as Appendix 3, is required. This contract form will be utilized for those customers seeking to participate in the TDG. The standard form contract preserves the structure of the NEM program agreement but improves upon it by allowing for the functionalities and technical requirements that will allow all distributed DG moving forward to contribute to grid reliability and/or mitigate the aggregate impacts of the increasing levels of distributed variable DG - requirements which the Companies are not able to include in every circumstance on existing NEM customers currently.

The Companies value DG as a resource that enables customer choice, and, to the extent that DG energy displaces fossil fuels as opposed to other renewable energy sources, contributes to meeting renewable portfolio standards and creates a public benefit by avoiding emissions and other impacts associated with burning fossil fuels. The Companies intend to continue to offer customers choices to manage their energy use. However, the Companies believe that to ultimately ensure a sustainable future for DG, it is necessary to transition away from the current NEM program. This transition will begin with the reinstitution of a NEM program capacity.

II. DISCUSSION

A. Based Upon Study Results, Transient Overvoltage Impacts Can Reasonably Be Addressed Up To A Circuit Penetration Of 250% of GDML.

As discussed more fully in Appendix 1, through a collaboration with SolarCity and the Electric Power Research Institute certain inverters were tested at the National Renewable Energy Laboratory in Golden, Colorado. The performance of each selected inverter was tested under controlled conditions to determine the extent to which overvoltage occurred and the speed at which inverters tripped off line when test circuits were suddenly islanded. Tests were conducted with increasing ratios of PV generation to circuit load. In general, the test results indicated that there was a correlation between the levels of overvoltage and increasing ratios of PV generation to circuit load, i.e., higher ratios of PV generation to circuit load resulted in higher levels of overvoltage when the circuit was suddenly islanded. The test results also indicated that the tested inverters could trip off extremely quickly to mitigate the extent to which overvoltage occurred. The Companies' evaluation of the test results indicates that transient overvoltage occurs at circuit penetration levels greater than 120% of GDML but less than some upper bound. The transient overvoltage threshold may be increased such that load rejection overvoltage will occur in the non-prohibited region, or narrowly outside of the ITIC curve. In order to establish a new, higher upper threshold for transient overvoltage considerations, the Companies considered the following factors:

- The laboratory tests were conducted on inverters one at a time. Under actual field conditions, there may be hundreds of different models of inverters tripping off simultaneously in a load rejection scenario. Field data from other studies and locations indicates that voltage impacts vary depending upon the size of the individual DG project and its location on the distribution circuit, in particular its distance from the distribution substation. These factors can substantially impact the result.

- Actual field conditions include dynamic loads and electrical components and equipment not simulated in a carefully controlled laboratory test environment. Data from a load rejection event occurring in field conditions is not well documented by the industry or by the Companies, as the NEM program continues to take distribution circuit penetrations to unprecedented levels.
- To protect customers and the power system, actual experience should be obtained with gradually increasing penetration levels to support the conclusion that overvoltage conditions do not occur. Circuit monitoring will be used to detect transient overvoltage issues as penetration levels are increased.

In consideration of the test results, the ITIC curve and the factors identified above, the Companies have concluded at this point that it would be reasonable to increase the allowable circuit threshold for transient overvoltage concerns from 120% of GDML to 250% of GDML once the program transition requested through this Motion can be approved.

It should be noted that transient over-voltage is not the only impact considered in evaluating distributed generation interconnections, and circuit penetration level is not the sole factor determining the impacts and mitigation requirements for a proposed interconnection. With the ever increasing levels of distributed generation, impacts occur on the circuit equipment and at the system level. These impacts require mitigation.

Mitigation can be expected to include a combination of minimum capabilities and requirements for the DG, modifications to circuit equipment and modifications to the overall power system. The mechanism to identify whether mitigation measures are required is the screening process provided in Rule 14H, including Supplemental Reviews. The screening process will consider the results and findings from the operational data from circuit-level monitoring, operational and system studies, area network studies, and evaluation of system events. Technical issues at the circuit level, area network level, and the system level may arise and may need to be mitigated or otherwise addressed.

As discussed in more detail below and in Appendix 5, due to the small size of their systems and their already high DG penetration levels, the Moloka'i and Lana'i systems are the first to experience very significant system level issues. The total system load on these islands is substantially lower than on the larger islands and the relative penetration of DG is highest. However, with increasing levels of DG on all systems, these impacts will eventually also occur on the larger islands. System level issues that will need to be mitigated include managing DG power production when it exceeds demand (excess energy), means to plan and operate the system with the high levels of variable output DG (system energy balancing and frequency control), and ensuring that the power systems remain operable through expected faults and contingencies during periods of high DG production (system security and reliability).

As discussed in the Companies' monthly update on its plan to clear the queue submitted on January 6, 2015 in this proceeding, rapid progress in approving outstanding applications is expected to be made over the next few months after the NREL study results are finalized. That will allow processing of customer projects on heavily penetrated circuits, predominantly over 120% DML, which were delayed by the need to address transient overvoltage concerns. This will occur following completion of inverter testing and self-certification, and compliance with the interconnection requirements described in the Companies' October 31, 2014 letter. As stated above, the Companies' interconnection requirements are subject to change, relaxed or tightened, in the future based on continuous circuit and system monitoring, review of operational data from system events, and engineering analysis of PV impacts at the system level. These activities are occurring and will continue on each of the island systems.

B. Strategic Investments to Add Long-Term Customer Value.

As noted above, through Exhibit A, the Commission identified a need for the utilities to make strategic capital investments which provide long-term customer value, and expressed support for efforts to cost-effectively enable the integration of higher levels of renewable resources. As expanded levels of penetration will likely require some level of circuit and possibly area network and system upgrades, the Companies are committed to making strategic and cost effective capital investments to upgrade the Companies' infrastructure to accommodate any increased thresholds and corresponding higher levels of renewable energy.

With the fairer and more cost-effective pricing proposed for the TDG, these renewable, distributed, grid friendly resources represent a benefit to all customers. With regard to how the Companies should prioritize this upgrade work, the Companies will work with the solar industry and key stakeholders to identify and address technical issues, evaluate potential upgrades to address such issues and their cost effectiveness, and fully evaluate and consider the needs of other distributed generation procurement programs such as the State's GEMS program.

C. Implementation of Recent Commission Guidance and Movement Toward a 21st Century Generation System Requires Transition to DG 2.0 and Reinstitution of a NEM Program Capacity Level.

Through a series of recent Orders, the Commission has made clear that the significant technical, market and public policy changes that have been and continue to occur in the utility and renewable energy environment in Hawai'i must be considered for purposes of ensuring the acquisition of a robust long-term portfolio of as-available renewable energy projects that are in the public interest. Most recently, the Commission has emphasized the procurement of high penetrations of lower-cost, utility-scale renewable resources that have preferred characteristics that are beneficial to the utility system. The Commission has also expressly noted that over-reliance on distributed solar PV capacity could hinder development of attractive alternative renewable energy resources, which may have more favorable production characteristics (e.g., higher capacity factor, better economics, etc.) due to the greater curtailment risk associated with excess energy and system level constraints. Taken together, the Commission's statements and directives lead to the conclusion that procurement of higher cost, distributed solar PV resources which are creating circuit and system level operational concerns, and which can preclude the procurement of lower cost energy from resources with superior operational characteristics, must be addressed with changes to the current program.

1. The Commission Has Provided Both Policy and Technical Guidance on the Procurement of New Renewable Resources.

a. **<u>Order No. 31354</u>**

The Commission provided its detailed comments with regard to the significant changes that have occurred in the utility and renewable energy environment in Hawai'i since 2008 through its July 11, 2013 Order No. 31354 Providing Guidance for Development of the Draft Final Oahu 200 MW Renewable Energy RFP in Docket No. 2011-0225 ("Order No. 31354"). Through Order No. 31354, the Commission noted that the "determination of what constitutes an optimal portfolio of as-available renewable energy resources for the Oahu grid is becoming more complex and challenging, given the numerous changes that have occurred over the last five years." Through Order No. 31354, the Commission discussed what it viewed as the "more noteworthy technical and market changes" for the purpose of providing a "foundation and understanding for the commission's decisions." Among those changes most relevant to this discussion are:

(1) Hawaiian Electric's annual electrical sales have been declining at an increasing rate, particularly on Oahu. The Commission noted that this "structural decline in electric sales" if continued into the future, could have several implications relative to acquisition of as-available renewable energy for Oahu. These included: (a) the total amount of as-available renewable energy resources that the Oahu grid can accommodate utilizing existing generation technology but without significant curtailment may be declining; and (b) Hawaiian Electric will need to become more judicious in terms of the amount and type of renewable energy projects selected for development given that there may be less grid capacity for development to accommodate as available renewable energy resources. (Id. at 17-18) Although the Companies are compensated for declining

sales under the decoupling regulatory model, the inequitable and increasing cost shift to non-NEM customers from those with NEM systems must be addressed.

(2) Distributed solar PV installations are growing at an exponential growth rate and are beginning to alter the net system load profile which could affect curtailment of existing and future utility-scale wind and solar PV projects on Oahu. (Id. at 19-20)

(3) <u>Reliance on a single renewable energy technology or island location may not produce the best long-term preferred portfolio of renewable energy projects that would be in the public interest</u>. It is important that the portfolio evaluation process analyze and rank renewable energy projects from a long-term public interest perspective in order to ensure inclusion of more economically beneficial projects that may take longer time to develop, and might be otherwise foreclosed if the utility project development queues are filled with only near-term projects. Selection of shorter lead-time renewable projects could preclude development of alternative projects with greater overall customer benefits, which results in a potential foregone economic benefit or an opportunity cost. (Id. at 24-25) (Emphasis supplied)

b. <u>Exhibit A</u>

As noted above, on April 28, 2014 in Docket No. 2012-0036, the Commission issued Order No. 32052. Attached as Exhibit A to Order No. 32052 were the Commission's Inclinations on the Future of Hawaii's Electric Utilities. Through Exhibit A, the Commission provided its "perspectives on the vision, business strategies and regulatory policy changes required to align the HECO Companies' business model with customers' interests and the state's public policy goals." (Id. at 1)

Specifically, as a part of the overall task of creating a 21st Century generation system, the Commission directed that the Companies should "expeditiously seek high penetrations of lower-cost, new utility-scale renewable resources" (Id. at 4) (emphasis supplied). Additionally, the Commission emphasized that the Companies should seek to integrate the "maximum level of cost effective renewable resources while maintaining adequate reliability of the electricity grid" (Id.) (emphasis supplied). Moreover, the Commission stated that "it is necessary that the Commission prioritize the review and approval of projects that exhibit preferred characteristics that are beneficial to the system" (Id. at 5) (emphasis supplied); and that the Companies "pursue a balanced portfolio of new energy resources" (Id.).

As the Commission noted at page 7 of Exhibit A, "[a]ll generation resources should contribute to system stability." The Commission stated:

> *Traditionally, utility-owned generation provided most of the grid support services required to maintain system stability. On island systems with rapidly growing utility-scale and distributed variable resources, individual utility-scale projects and, in aggregate, distributed resources can have a significant impact on system stability. Consistent with meeting the future needs of Hawaii's island grids, the electric systems should evolve such that all generation resources, whether utility, IPP or customer- owned, will contribute to maintaining system stability. Therefore, to maximize the integration of variable renewable energy resources, the Commission expects the HECO Companies to require all generators to address and support system stability consistent with their resource characteristics and state-of-art technical capabilities.*

(Emphasis supplied)

c. **Order No. 32053**

On April 28, 2014, the Commission issued Order No. 32053 in Docket No. 2011-0206.

At page 23 of Order No. 32053, the Commission provided a detailed description of recent Distributed Generation interconnection trends including the status and level of net energy metering and the impacts of those projects on the system. At page 31, the Commission offered certain observations and perspectives on distributed generation issues. Relevant to the instant discussion, the Commission stated:

> *It is axiomatic that customer distributed generation must be interconnected to electrical grids in a safe and reliable manner. The rapid growth in solar PV systems over the last several years has likely consumed the distributed generation safety, power quality, and reliability "reserve margins" that previously existed in electric distribution systems. *** It is the sole responsibility of the HECO Companies to address interconnection challenges before adverse consequences manifest themselves in terms of poor customer reliability or unsafe operating conditions.* (Id. at 35)
>
> ***
>
> *A significant technical challenge related to customer solar PV systems is the ability for net energy metering (NEM) customers to export their excess solar energy onto the grid, in an unscheduled and uncontrolled manner, regardless of whether the grid could physically or economically utilize the energy.* (Id. at 36)
>
> ***
>
> *System level reliability could be adversely affected in several ways as a consequence of integrating significant amounts of distributed solar PV capacity. First, conventional generators, which currently provide dispatchable power and ancillary services, would be displaced during the daily solar output period.* (Id. at 40)
>
> ***
>
> *Second, distributed solar PV, similar to utility-scale solar and wind resources, are electronically-coupled to the grid through power inverters that convert solar DC power into 60 Hz AC power. Unlike the displaced conventional synchronous generators, power inverters have technical limitations, that when aggregated in sufficient volume could create dynamic stability challenges for the power grid.* (Id.)
>
> ***

The resulting lower day-time net system loads will, by necessity, displace the operation of conventional synchronous generation in order to balance supply and demand. As a consequence, a power grid would be less robust and resilient to reliably withstand short-circuit faults or other grid contingency events from a system level perspective. (Id. at 40-41)

***

The interconnection of distributed solar PV systems, and more importantly, the unscheduled and uncontrolled export of excess solar energy onto the grid, could eventually create curtailment risks for existing and future utility-scale solar PV, wind, and other renewable energy projects. This occurs because the total amount of variable renewable energy that could be accommodated reliably on each island grid, at the system level, is limited. When variable energy congestion occurs due to excess energy at the system level, utility-scale renewable energy projects would be curtailed due to the current technical inability to curtail distributed generation exports onto the grid. This can also result in loss of grid access to the reliability capabilities that are inherently provided by utility-scale wind and solar PV projects pursuant to generator performance standards set forth in interconnection requirements. (Id. at 41)

***

As a consequence, distributed solar PV customers effectively have higher priority and preferential grid access than do the utility-scale projects, which serve all customers, because the utility is forced, by technical default, to curtail the purchase of low-cost, wholesale renewable energy that otherwise may provide economic savings to utility customers. In its place, the utility is effectively required to purchase, at retail rate levels, uncontrolled solar PV energy exported onto the grid by distributed solar PV customers. (Id. at 42)

***

A large amount of solar PV capacity can create major daily operational challenges for island grids as a consequence of substantially reducing the day-time net system load that must be served by dispatchable fossil and renewable generation. If the island grid lacks sufficient quick-start generation, other flexible load-following generation capacity, or large-scale bulk energy storage resources, it may not be possible to serve major morning ramp-down and late afternoon ramp-up of net system load requirements as a result of large quantities of solar PV capacity. (Id. at 43-44)

***

Over-reliance on distributed solar PV capacity could also hinder development of attractive alternative renewable energy resources, which may have more favorable production characteristics (e.g., higher capacity factor, better economics, etc.) due to greater curtailment risk associated with excess energy and system level constraints. (Id. at 46)

***

Distributed solar PV generators could be required to utilize advanced inverter features, energy storage, demand response or other technologies to supply dispatchable capacity, ancillary services and other grid support services that otherwise would have been supplied by the conventional generators displaced by the distributed generation. (Id.)

***

Limiting, or precluding, the export of excess distributed solar PV energy could be an effective, and perhaps significant, mitigation measure for a variety of reasons. (Id.)

***

The commission believes it is unrealistic to expect that the high growth in distributed solar PV capacity additions experienced in the 2010 - 2013 time period can be sustained, in the same technical, economic and policy manner in which it occurred, particularly when electric energy usage is declining, distribution circuit penetration levels are increasing, system level challenges are emerging and grid fixed costs are increasingly being shifted to non-solar PV customers. (Id. at 49)

***

The commission submits that the distributed solar PV industry in Hawaii will, out of necessity due to their accomplishments thus far, have to migrate to a new business model, not unlike what is expected for the HECO Companies as a result of disruptive technologies. The distributed solar business model will need to shift from a customer-value proposition predicated upon customers avoiding the grid financially - but relying upon it physically and thereby creating circuit and system technical challenges - to a new model where the customer-value proposition is predicated upon how distributed solar PV benefits both individual customers and the overall electric system, and hopefully becomes a key contributor to Hawaii's grid modernization, and most importantly as a consequence, customers are compensated by the utility for the grid value created. (Id. at 49-50)

(Emphasis above supplied)

2. The Companies Submitted Their Distributed Generation Interconnection Plan, Including a Proposal to Transition Away from the Existing NEM Program, in Response to the Commission's Directives

Through Order No. 32053, the Commission concluded that based on the Commission's observations and perspectives, "further information and analysis is necessary in order to analyze potential constraints that exist due to high penetration of solar PV systems, and as a result, develop strategies and plans to mitigate these constraints." (Id. at 50) The Commission therefore, ordered the Companies to file a Distributed Generation Interconnection Plan with the commission within 120 days of the date of Order No. 32053. The Companies DGIP was filed for the Commission's consideration on August 26, 2014.

As a part of the DGIP, the Companies set forth their strategies and proposed actions to increase DG capacity on their systems while preserving system reliability. To address the technical and system security[3] challenges, the DGIP outlined specific circuit upgrades required to enable higher levels of DG penetration in a proactive manner, and plans to implement advanced inverters and other technologies, to maintain safe and reliable service. The Companies also discussed how they would seek to establish a revised set of DG tariffs as a part of an approach to distributed generation called "DG 2.0" which would enable the interconnection of DG systems in a manner that fairly allocates costs among all customers and appropriately compensates DG providers. This

[3] System security, in this context, refers not to the physical security of the electrical infrastructure from natural or man-made threats, but rather to the ability of the utility to maintain stable and reliable operation of the grid under steady-state conditions as well as under conditions where events, such as sudden and unexpected generator or transmission line outages, disturb the stability of grid operations.

included an introduction of multiple ways to access DG resources – including export and non-export systems and community solar to facilitate the benefits of DG across all customers.

With regard to Non-Export and "smart export" systems ("NESE"), Hawaiian Electric is currently implementing several pilots with multiple local and national PV and storage vendors in Hawai'i to provide concrete, real-world performance data and operating experience on the ability to manage load using PV-only, battery-only and PV/battery combined systems. Systems with the capability of smart PV/coupled with battery energy storage such as Gridco and customer-sited storage capabilities with intelligent software such as Stem, focus on features such as advanced technical interfaces, visibility to measured data and 24/7 real-time controls of DER functions. Customer-sited storage capabilities, which include the on-going Energy Excelerator demonstration projects that the Hawaiian Electric Companies have underway, are a component of the Companies' total portfolio approach to developing innovative solutions to manage autonomous and/or aggregated controllable load-to-generation ratios at the circuit level while enabling increased PV interconnections. These innovative solutions include advanced DER and Demand Response applications, battery energy storage charge management, and high resolution usage and generation data analytics. With the large potential for residential and commercial storage systems to support Hawai'i's energy needs, developing the practical technical and operational experience with these systems is a critical first step prior to offering widespread programmatic adoption. These investigative pilots, which the Companies anticipate could include as many as 1,000 total projects, are intended to characterize and quantify those benefits with the aim of accelerating the use of distributed storage systems on the customer side of the meter to support localized circuit-level and system-level needs.

The Companies' anticipated community solar program will provide the benefits of solar energy to those customers who either choose not to or do not have the necessary access to install rooftop solar on their property. Generally, the community solar facility will be developed at an optimal location with energy being delivered to and benefiting ALL customers via the grid. A community solar facility is developed in the most cost-effective manner and at a scale that allows as many community solar customers to participate as possible. Interested community solar customers purchase an interest in the energy produced from the community solar facility to off-set their monthly bill without installing solar panels on their property. The monthly electric bill of community solar customers is credited for the community solar electricity used by Hawaiian Electric equal to their pro rata interest in the community solar facility.

Finally, the DGIP also made clear that regulatory and policy reforms would be essential to ensure that the incentives for future DG interconnections are aligned with the interests of all customers. To that end, the DGIP described policies that better reflect the value of DG to the grid, and the value of the grid to DG customers. These policies entailed both: (1) clearing the existing queue of DG projects (including NEM program applications) as circuit and system-level constraints allow; and (2) transitioning the NEM program (while revised DG tariffs are being developed) together with the development of a non-export option. (See, DGIP at 1-4 and ES-4)

The DGIP provided an extensive discussion of both the economic and technical reasons why a program transition is required in order to achieve a more equitable and sustainable distributed generation procurement program in the future.

a. Background to NEM Program and Current Limits

By statute, NEM was intended to be offered on a "first-come-first-served basis" until the total rated generating capacity produced by eligible customer-generators equals 0.5% of the electric utility's system peak demand. However, this cap was increased over time as part of the Commission's investigative docket on NEM, Docket No. 2006-0084. The Commission released its most recent decision related to NEM limits on January 13, 2011, in which, among other things, it approved a stipulation filed January 7, 2010, between the Companies and the Consumer Advocate to eliminate NEM system-wide caps and replace them with a 15% of distribution circuit peak load threshold for DG penetration. The Companies believe that the intent of the NEM program at its inception, in combination with federal and state incentives, was to nurture a developing technology and industry, because the cost to self-generate clean renewable energy was prohibitive at the time. However, PV system costs have decreased dramatically during the last several years, and the need to provide retail level compensation to incent DG no longer exists.

For the Companies, there is currently no system cap for NEM generators. As mentioned above, the system cap was replaced with a per-circuit cap of 15% circuit peak in the NEM Docket. As a matter of practice, however, the penetration levels were used as a technical evaluation tool to identify interconnections that might warrant further engineering assessment for circuit impacts which could require mitigation measures to protect other customers, utility equipment, and DG customers from unacceptable impacts.

DG now far exceeds 15% on most circuits and 100% on a number of circuits. As of the date of this Motion, the NEM program penetration has grown to a level 50-60 times that originally envisioned when it was capped at 0.5% of system peak. As shown in Figure 6-2 of the DGIP, the NEM program is by far the largest and most costly of the renewable energy resources when compared with the Companies' other resource contracts.

b. <u>NEM Penetration Levels and Corresponding Impacts</u>

The total number of solar PV systems interconnected on the Companies' grids as of December 31, 2014, is approximately 51,000, with a total capacity of about 390 MW. Of those installations, 97% take advantage of the NEM program. More than 70% of rooftop systems are on O'ahu. With approximately 36,400 PV systems and 283 MW on O'ahu as of December 31, 2014, approximately 13% of Hawaiian Electric residential customers now have rooftop solar, an appreciably higher percentage than any mainland utility. On the Island of Hawai'i, 10% of Hawai'i Electric Light residential customers have rooftop solar, and 11% of Maui Electric customers have rooftop solar. The Solar Electric Power Association has confirmed in recent reports that Hawai'i leads the nation in the amount of PV penetration per capita—more than triple the amount of the next state (Hawai'i 16.9, Arizona 4.3, California 4.2, and Colorado 2.9 (installations per 1,000 people)).

The levels of DG are so high in Hawai'i that this resource is essentially squeezing out room on the Companies' grids for other lower cost utility-scale projects that provide the same environmental benefits but have increased economic benefits for all customers, and reducing the ability to accept energy from existing and planned renewable energy projects. Utility-scale facilities have economies of scale related to their large size, which can provide lower cost energy to all customers, and are typically able to provide more favorable grid operational characteristics, but the potential for such projects has been displaced by NEM systems, which typically do not extend those economic benefits to all customers. The Companies are concerned that NEM projects will prevent the Companies from procuring lower cost energy from other forms of renewable energy, such as geothermal facilities, biomass, waste-to-energy, and lower cost distributed generation resources.

The issues also go beyond simple production costs. The high levels of DG have reduced system reliability and security due to the technical and operational characteristics of these resources. These impacts result from the variability of power output, difficulty in forecasting production, excess production during daytime periods with limited production at evening peak, disconnection during system disturbances, issues associated with being connected to the radial distribution system, and lack of visibility and control. Continued growth in DG as an option for customers remains an important part of the Companies' future energy plans. Mitigation of the economic and technical issues to ensure a sustainable DG program will require a combination of grid capital investments and modifications and changes to the interconnection requirements for and capabilities of the DG.

c. Achieving Fairness in the Procurement of Renewable DG

Other than fuel and purchased energy, the costs of generating, transmitting, distributing, and managing electricity over a complex electric system are primarily fixed, representing long-term commitments of capital to build and maintain facilities. These fixed costs are recovered mainly from residential and small commercial customers and, to a lesser extent, large commercial customers through a volumetric charge (i.e., kWh usage varies on energy consumption). In such a rate design, the more energy a customer consumes, the higher the kWh charge, the higher the electricity bill, and the higher the contribution to fixed costs; the fewer kWh consumed, the lower the bill, and thus, the lower the contribution to fixed costs. The residential and small commercial customer classes do not have demand charges and the utility recovers over 85% and over 65% of fixed costs, respectively, from these customers through the volumetric (energy) charge. In Hawai'i, with the advent of NEM, customers who self-generate are able to reduce their net energy usage, thereby reducing their volumetric charges and their contribution to the fixed costs associated with safely and reliably operating and maintaining the entire system. This phenomenon shifts a portion of the fixed cost recovery from customers who self-generate to those who do not. This cost shifting is an equity issue in rate design. The Companies believe that NEM pricing at full retail rates represents an embedded subsidy to PV systems, a view that is shared by many utilities in the United States and worldwide.

The Companies estimate annualized lost contribution to fixed costs (cost shift) of approximately $53 million (Hawaiian Electric, $38 million; Maui Electric, $7 million, and Hawai'i Electric Light, $8 million) based on installed NEM capacity as of December 31, 2014. The estimated O'ahu monthly typical residential bill impact is $3.30.[4] An annualized cost shift of $53 million is large enough to raise an equity issue between those who self-generate and those who do not. This is a public policy issue that must be addressed, especially given the rapid rate at which this absolute cost shift is increasing. The total lost contribution to fixed cost across the Companies has increased from an

[4] The typical residential usage for O'ahu is 600 kWh per month.

estimated annualized $19 million based on installed NEM capacity as of the end of 2012, to an annualized $38 million at the end of 2013, and to an annualized $53 million at the end of 2014[5].

California recently passed AB 327, which allows the Commission to modify the rate designs of investor-owned utilities to make them more equitable and to reflect the cost of serving customers. Oklahoma recently passed SB1456, which directs the Oklahoma Public Utilities Commission to establish a separate DG customer class, which then will pay a form of a fixed monthly surcharge toward the Oklahoma utilities' fixed costs. The Companies have examined these recent legislative efforts to identify aspects that could be adopted for use in Hawai'i.

d. **The Need for Program Transition**

Consistent with the Commission's guidance, the Companies are committed to enabling DG growth as a segment of the total resource portfolio. This commitment includes continued development of mitigation measures through research and engineering, such as was done to propose modification of the transient overvoltage threshold and identification of utility projects to mitigate DG system impacts. However, it is recognized that DG growth cannot be sustained under the same regulatory, business, and operational policies that have governed this industry during the past 5 years. Achieving this vision requires strategic initiatives encompassing regulatory reform, operational improvements, and a range of new DG-related products and services.

---

[5] Annualized amounts for December 31, 2012 and 2013 are the sums of the Companies' Total Lost Contributions to Fixed Costs in Appendix A of the 2013 Net Energy Metering Status Report, submitted to Commission January 31, 2014. The annualized amounts for December 31, 2014 to be filed 2014 Net Energy Metering Status Report on or about January 31, 2015.

Together, these initiatives can be applied over the short, medium, and long term to ensure a smooth transition to this new model for DG.

The Companies' strategic vision for DG encompasses alternatives for the rates governing DG interconnections. As part of this effort, the current NEM program needs to be transitioned to a tariff structure for dispatchable DG systems that more fairly allocates fixed grid costs to DG customers and compensates customers for the value of their excess energy.

Currently, DG systems installed under the Companies' standard interconnection agreement ("SIA") are not compensated for energy that is exported to the grid. Customers interconnecting under the SIA are economically incentivized to install a DG system that does not exceed their load. The SIA typically is utilized by customers who install systems larger than 100 kW which are not eligible for NEM. SIA systems can be considered as a form of Parallel Non-Export DG without energy storage. NEM customers, on the other hand, are incentivized to maximize their annual energy production to potentially reduce their annual net energy usage to zero. Since most of these systems are PV-based, the incentive is for excess production to export during the day and compensate for the periods when the sun's energy is not available. The Companies are obligated under NEM to purchase excess energy generated during the day at retail rates and to credit customer usage during hours when the DG is not generating. There currently is no limit imposed by tariff on how much energy a NEM customer can export to the grid relative to their electricity usage as excess energy credits are trued-up on an annual basis (i.e., no continuous credit rollover).

The majority of existing DG (NEM and SIA) do not have identified mitigation measures to support the system (i.e., do not have fast-trip capability to mitigate transient over-voltage conditions; or the ride-through settings required to remain connected through system disturbances, or the ability to reduce DG production when it exceeds demand on the system). While adoption of these interconnection requirements is important for all DG, exporting NEM has less attractive economic characteristics for the utility and non-participating customers, and contributes more significantly to system security and reliability issues because of the incentive to export energy during the day. Because of the desire to "zero out" usage, these systems maximize export during the day, which utilizes the available infrastructure which might otherwise support a greater number of non-exporting DG systems, and disproportionately contributes to the system security and reliability issues in comparison with non-exporting DG. Many of the system and circuit level issues are proportionate to the amount of export: greater export causes increased potential for excess energy at the system level, more complexity in the underfrequency load-shed scheme requirements, and greater system impact from DG disconnecting during disturbances. There is also increased potential for circuit-level reliability impacts and need for equipment upgrades. The larger the export during the day, the greater potential there is to displace lower-cost energy including renewable resources.[6] The excess energy exported from NEM DG is purchased at essentially a retail rate, whereas, SIA reduces demand. System-level excess energy caused by exporting DG is a serious system security concern as it cannot be managed for reliability

[6] The Companies note, however, that increasing daytime load, such as through the State's planned rail system, has the potential to accommodate additional PV generation without the risk of displacing generation from other renewable resources.

or economic reasons. The capability to control exporting DG is currently limited and is in most cases not allowed under existing statutory provisions.

One of the major system security issues facing the Companies now and as the DG PV levels increase is how these DG systems behave and respond after a grid disturbance (e.g., trip of a particular generating unit or transmission line due to a fault). Generator trips and transmission line faults cause short-term excursions in the system frequency and voltages away from normal ranges. These excursions are halted by equipment response, and as other system equipment operates to stabilize the power grid following the event. Historically, DG resources were required to disconnect during these momentary excursions in accordance with standards that were developed assuming the total amount of DG was insignificant on a given power system. When large amounts of DG, such as are connected on all of the power systems in Hawai'i today, disconnect during these short-term excursions, it magnifies the disturbance, causing more extensive outages than would otherwise occur. Analysis indicates aggregate loss of DG during disturbances may lead to system failure in some circumstances, at present levels of DG, for all of the power systems. The ability of all generation, including DG, to remain connected through momentary frequency and voltage conditions is important and necessary to ensure the system will stabilize after a disturbance. The Companies have moved to require DG resources to remain connected, or ride through, the momentary frequency and voltage conditions that occur for many grid events. Implementing DG ride-through capability is separate from, but complementary to, circuit-based mitigation measures aimed at addressing high circuit penetration levels and transient overvoltage issues. However, there are a number of installed DG systems which will not be able to be retrofitted to achieve this ride-through capability and will continue to trip offline during disturbances, thereby magnifying the impact of the disturbance.

During these grid disturbances, the electric system's resources need to respond immediately and automatically to the system imbalances. This response has historically been provided by the primary frequency response of generators which have reserve capacity (online contingency reserve) in combination with fast-tripping underfrequency load-shed. The primary frequency response of contingency reserve determines the maximum deviation in frequency that will occur before the system stabilizes. In isolated power systems (such as those on islands), the primary frequency response of contingency reserve must be extremely fast. As the power system evolves and displaces thermal generation with increasing amounts of variable generation, the required response time of the contingency reserve becomes even faster due to the reduced available inertia and reduced frequency response from generation. A larger amount of generation is being provided by resources that do not have a primary frequency or inertial response, such as inverter-based DG PV and wind. The need for fast response has been increased by the loss of DG during disturbances. If the primary frequency response is not fast enough, excessive underfrequency load-shedding will occur and the system may fail to reach stable operation. Analysis indicates that the response time precludes many types of energy systems from supplying the necessary fast-responding primary frequency response from the contingency reserve. Even traditional contingency reserve carried on conventional generation will not be fast enough to provide acceptable contingency response with the reduction in inertia and frequency response resulting from the change in resource mix and the loss of some of the DG during disturbances.

For instance, the contingency reserve implemented as part of the Under Frequency Load Shed system must be fully deployed within 7 cycles (0.12 seconds) of reaching the target frequency. Primary frequency response from the contingency reserve through governor action of thermal generation is not fast enough to prevent frequency from reaching load-shed levels for many events which previously did not shed load (as observed in actual data and expected through analysis). Analysis shows unless a faster primary frequency response can be implemented, certain events will result in loss of all underfrequency load shed blocks and potentially the entire system. The historical methods used in Hawai'i (and elsewhere) to provide primary frequency response are now simply too slow to respond to the new system characteristics as a result of the increasing levels of DG. In particular, the systems are very vulnerable if frequency and voltage conditions are longer than 8-9 cycles, such as occur during secondary fault clearing. This situation is further complicated by the fact that the underfrequency load-shedding used to stabilize the system during large frequency disturbances by reducing system demand, now must be modified to reflect the fact that when solar energy is available, many under frequency circuits will have greatly reduced load, and may even be exporting power, due to the DG PV production. This greatly complicates the design of an effective scheme. Another complication is that the underfrequency schemes must avoid shedding too much load, due to the potential to create over-frequency, which will trip legacy PV systems.

DG PV can result in challenges for system operation during steady-state conditions. The operators must dispatch other generation to meet a net of the system demand minus the production from DG PV. This production is not presently visible to the system operator and, although forecasting has been developed, the forecasts are subject to a high level of uncertainty. Further the DG PV has variable production which can ramp up and down quite quickly. If the operators bring too little generation online, there will be insufficient generation to serve demand. If operators bring too much generation online, frequency will increase and a cascading event can occur. With ever-increasing DG PV production, day time demands are decreasing to the point where the systems are vulnerable to excess energy production, even with only the minimum online generation from non-DG sources. Without any means to control the output of the DG, the operator will not have a way to balance supply and demand.

The Companies are moving to mitigate these system level risks, which have been described in many filings including the Companies' Power Supply Improvement Plan ("PSIP") reports. Some of the mitigation measures include:

1) Installing "fast acting" Battery Energy Storage Systems (BESS) that will provide contingency reserve for the larger island systems if effective.
2) Reducing secondary fault clearing times.
3) Implementing expanded inverter ride-through requirements for DG.
4) Modifying the under frequency load shedding scheme to address impacts of reduced day-time load because of PV production.
5) Controlling future DG for excess energy.
6) Increasing the available regulating ramp rates needed to balance fast-ramping DG

Until these measures are implemented, the Companies operate with the identified risks, and which increase in severity with the growth in DG. While the Companies recognize these increased risks, the Companies are proceeding to implement their plans to transform the grid to accommodate more DG which includes increasing the allowable circuit threshold from 120% of GDML to 250% of GDML, once the program transition requested through this Motion can be approved.

As noted above, due to the small size of the systems and the already high DG levels, Lana'i and Moloka'i are the first to experience very significant system level issues for steady state and transient conditions. The total system load on these islands is substantially lower than on the larger islands and the relative penetration of DG is highest. As described more fully in Appendix 5, Moloka'i in particular has reached a point where additional DG must be subject to output control by the Maui Electric operator in order to keep the system reliable and operable. Maui Electric must be able to match generation to the demand at all times in order to provide reliable power and maintain the system frequency. With only the minimum generation that Maui Electric can run and still maintain reliability, the capacity of DG that has been currently installed and approved to be installed (approximately 2.5 MW) will exceed the ability of the system to use the DG energy during the minimum day time load of the system (approximately 2 MW). At this time, Moloka'i is near or at the point where generation cannot be matched to demand, and frequency cannot be maintained reliably. Accordingly, and as illustrated in Appendix 5, on Moloka'i, Maui Electric will not be able to interconnect any more DG systems whose output cannot be controlled by the utility on the island of Moloka'i until such time that daytime demand increases by a sufficient extent and/or when there are other means to use the available excess energy in a cost effective manner.

However, with increasing levels of DG on all systems, these impacts will eventually also occur on the larger islands. System level issues that will need to be mitigated include means to manage when DG power production exceeds demand (excess energy), ability to plan and operate the system with the high levels of variable output DG (system energy balancing and frequency control), and ensuring that the power systems remain operable through expected faults and contingencies during periods of high DG production (system security and reliability).

The Companies value DG as a resource that enables customer choice, contributes to meeting the renewable portfolio standards, and, to the extent the DG energy is displacing fossil fuels, avoids emissions and other impacts associated with burning fossil fuels. The Companies intend to continue to offer customers choices to manage their energy use.[7] However, the Companies believe that, to ultimately ensure a sustainable

---

[7] The Companies are working on the following solutions as a way to proactively offer customers more options where high circuit penetration levels present interconnection challenges. These additional programs will provide a range of customer options for future DG applicants. The programs are:

- Non-export PV model with storage;
- Programmed charge and discharge PV and storage model; and
- Community solar program, which will allow customers on highly penetrated circuits and customers without space or access to rooftop PV (such as condo owners) to participate in shared solar projects through a financial arrangement as an offset on their bill.

The Companies are actively developing these alternatives, and will pilot or implement them in the first half of 2015 pending Commission approval to do so.

In addition, consistent with the Companies' plans, the Companies are pursuing or proposing:

- Grid scale storage to mitigate reliability impacts of the existing and growing distributed PV during system events and increased variability;
- Modification of underfrequency load-shed schemes to accommodate impacts of the distributed PV;
- Reduction in fault-clearing times to avoid loss of DG during faults and contingencies.
- Future low-cost grid scale renewable energy projects to help lower bills for all customers, including non-PV customers;
- Cost-effective demand response programs to offer customer options for lowering bills;
- Smart grid investments that enable network optimization and customer rate and pricing programs;
- Installing monitors on circuits to obtain actual distribution circuit data to monitor impacts of growing DG PV and to further future renewable DG integration work;
- A unified and transparent distribution interconnection queue; and
- Decreasing clearing times for transmission system faults in an effort to reduce risk of distributed energy resources tripping during system events

future for DG, it is necessary to transition away from the current NEM program. As discussed above, this transition will begin with the reinstitution of a NEM program capacity.

3. The Commission Has the Authority to Impose a Program Capacity Level

The provisions governing Net Energy Metering in the State of Hawai'i are set forth in §269-102, Hawai'i Revised Statutes ("HRS"). Section 269-102 (a) provides the Commission with the authority to modify the total rated generating capacity produced by eligible NEM program customer-generators:

> *Every electric utility shall develop a standard contract or tariff providing for net energy metering and shall make this contract available to eligible customer-generators, upon request, on a first-come-first-served basis until the time that the total rated generating capacity produced by eligible customer-generators equals .5 per cent of the electric utility's system peak demand; <u>provided that the public utilities commission may modify, by rule or order, the total rated generating capacity produced by eligible customer-generators ....</u>*
>
> ***

Section 269-102, also provides the Commission with the authority to exempt an island or utility grid system from the NEM program generating capacity requirements:

> *Notwithstanding the generating capacity requirements of this subsection, the public utilities commission may evaluate, on an island-by-island basis, the applicability of the generating capacity requirements of this subsection and, in its discretion, may <u>exempt an island or a utility grid system from the generating capacity requirements.</u>*

(Emphasis supplied)

With regard to the issue of generating capacity, Section 269-103, HRS, makes clear that the Commission has the authority to determine that an electric utility is no longer obligated to provide net energy metering to customer generators in its service area based upon the total rated generating capacity produced by eligible customer-generators of the utility in the utility's service area:

> *On an annual basis, beginning in 2003, every electric utility shall make available to the public utilities commission information on the total rated generating capacity produced by eligible customer-generators that are customers of that utility in the utility's service area. The public utilities commission shall develop a process for making the information required by this section available to electric utilities, and for using that information to determine when, pursuant to section* ***269-104, an electric utility is not obligated to provide net energy metering to additional customer-generators in its service area****.*

(Emphasis supplied)

With regard to the issue of additional customer-generators on the utilities' systems, Section 269-104, HRS, states that the Commission has the authority to increase the allowable percentage of the utility's system peak demand produced from eligible customer-generators in the utility's service area:

> *Notwithstanding section 269-102, an electric utility is not obligated to provide net energy metering to additional customer-generators in its service area when the combined total peak generating capacity of all eligible customer-generators served by all the electric utilities in that service area furnishing net energy metering to eligible customer-generators equals .5 per cent of the system peak demand of those electric utilities; provided that the public utilities commission may increase, by rule or order, the allowable percentage of the electric utility's system peak demand produced from eligible customer-generators in the electric utility's service area, whereupon the electric utility will be obligated to provide net energy metering to additional eligible customer-generators in that service area up to the increased percentage amount.*

(Emphasis supplied)

Through the Commission's Order Regarding Net Energy Metering Proposals, issued January 13, 2011 in Docket No. 2006-0084 ("January 13, 2011 Order"), the Commission discussed its authority to modify the NEM program capacity.

> *In addition, the Net Energy Metering Law provides a cap on the total power producing capacity of eligible customer-generators, which is currently set in the statute at 0.5 percent of an electric utility's peak demand. As with the maximum generating capacity of individual customers established in HRS § 269-101.5, the Net Energy Metering Law authorizes the commission to "modify, by rule or order, the total rated generating capacity produced by eligible customer-generators[.]"*

(January 13, 2011 Order at 3) (Emphasis supplied)

The January 13, 2011 Order also discussed how the NEM program was referenced in the 2008 Energy Agreement.[8] The Commission noted that while the parties to the Energy Agreement were in agreement at the time that there should not be system caps on the Companies' NEM program, the parties did agree that distributed generation interconnection as a whole should be "limited on a per-circuit basis, where generation (including [photovoltaic ("PV")], micro-wind, internal combustion engines, and net metered generation) feeding into the circuit shall be limited to no more than 15% of peak circuit demand for all distribution-level circuits of 12kV or lower." (Id. at 7-8) The Commission also discussed processes for the Companies to analyze whether such capacity could be increased, and the notification processes for projects which the utilities believe pose a significant risk to circuit reliability and safety or grid stability.

Specifically, the Commission referenced the provisions of the Energy Agreement which stated that "NEM currently provides an interim measure to encourage the installation of and pay for renewable energy generated from customer-sited systems, generally PV systems." (Emphasis supplied) The Commission noted that the parties to the Energy Agreement agreed that "NEM will be replaced with an appropriate feed-in

[8] On October 20, 2008, the Governor of the State of Hawai'i, the State of Hawaii Department of Business, Economic Development and Tourism, the Consumer Advocate, and the Hawaiian Electric Companies entered into a comprehensive agreement designed to move the State away from its dependence on imported fossil fuels for electricity and ground transportation, and toward indigenously produced renewable energy and an ethic of energy efficiency ("Energy Agreement").

tariff and new net metered installations shall be required to incorporate time-of-use metering equipment and, when time-of-use rates are implemented on a full scale basis in Hawai'i or the applicable area, the net metered customer shall move to time-of-use net metering and sale of excess energy."[9] (Id. at 8)

In summary, it is evident that the State always envisioned that the NEM program should have some limit, and indeed, that depending upon circumstances, entire islands or systems could be exempted from the obligation to provide a NEM program. Moreover, it is evident that the signatories to the Energy Agreement viewed the NEM program as an "interim measure" with a program cap that would eventually be supplanted by alternative procurement mechanisms as well as technical controls on capacity. In any case, it is clear that the Commission was granted and empowered with the discretion to modify or increase any capacity level to the NEM program.

4. Determining an Appropriate Program Capacity Level

As a part of their Stipulation in Docket No. 2006-0084 (Net Energy Metering proceeding) to effectuate the provisions of the Energy Agreement, while the Companies and Consumer Advocate proposed to eliminate NEM system-wide caps and replace them with a 15% per-circuit distribution threshold for DG penetration, their stipulation also stated that "[r]eliability and interconnection standards shall provide the basis by which protection measures on system reliability are maintained and periodically reviewed. . . .

[9] Consistent with the Energy Agreement, the Companies and Consumer Advocate proposed to replace the NEM program with the adoption of a Feed-In Tariff program in Docket No. 2008-0273. The Commission at the time chose not to end the NEM program and instead to keep all procurement options available subject to revisiting the issue as a part of the first FIT reexamination process. See Decision and Order issued in Docket No. 2008-0273, on September 25, 2009, at 17-18. That reexamination process is presently pending in Docket No. 2013-0194. In Decision and Order No. 32499 in that docket, issued on December 5, 2014, at Ordering Paragraph 5, the Commission noted that "[f]uture revisions or modifications to the FIT program will be addressed either in Docket No. 2014-0192, which has been established to investigate DER policies, or in Docket No. 2014-0183, which has been established to review the HECO Companies' PSIPs."

Overall system level caps can be derived based on these protection measures and re-evaluated." The Stipulation expressly stated that the Companies will remove the NEM system caps "with the adoption of the Rule 14H modifications and the establishment of Reliability Standards" in Docket No. 2008-0273.[10] (Id. at 11-12)

The Commission found the Stipulation on the Hawaiian Electric Companies' NEM System Cap to be reasonable. The Commission also supported the "assertion in the stipulation that additions of renewable energy generators at the distribution level could have an impact on overall grid reliability and responsiveness, and therefore must be "planned, assessed and reviewed in the context of the whole system in order to ensure circuit reliability, safety and grid stability." (Id. at 12) Accordingly, the Commission approved the stipulation, subject to the certain conditions. Pursuant to its "authority granted in HRS § 269-102" the Commission approved the adoption of "essentially unlimited system-wide limits when the per-circuit caps are in effect." The Commission noted however that with respect to system reliability, "the responsibility for assuring system reliability remains with the HECO Companies." Finally, with respect to implementation, the Commission stated that "with the 15% per-circuit cap in place, the commission expects the HECO Companies to remove the system-wide caps without waiting for final approval of reliability standards in the FIT docket." The Commission expressly stated that the "HECO Companies shall report to the commission if such an implementation schedule compromises system reliability, or is otherwise unfeasible." (Id. at 13)

[10] Reliability Standards were proposed to the Commission by stakeholder members of the Reliability Standards Working Group in Docket No. 2011-0206 on March 25, 2013. (See Reliability Standards Working Group Independent Facilitator's Submittal, Final Report, dated March 17, 2013, in Docket No. 2011-0206). Those reliability standards are pending for Commission consideration.

For the reasons discussed above, an unlimited NEM program has now become unsustainable and indeed contrary to other directives from the Commission and contrary to the objectives of the Companies to create a sustainable, affordable renewable energy future for all customers. The Commission's inclinations and directives cannot be implemented if distributed NEM, which is one of the most costly renewable resources, which displaces existing and potential generation with the characteristics necessary to support a modern grid, and which, particularly in the aggregate, impact reliability, is displacing more cost effective resources, such as utility scale renewable energy projects and lower cost distributed renewable resources. Therefore, it is reasonable to implement a new NEM program capacity level on a going forward basis.

An appropriate NEM program capacity should be set at percentage figures for each island system which reflect and include existing interconnected NEM customers, those NEM customers that have been approved for interconnection, those customers whose NEM applications are presently undergoing a review for interconnection, and an additional margin to account for some amount of new NEM applications that may be received through March 20, 2015, the requested approval date for this Motion. The Companies presently estimate these limits to be equivalent to the following percentages of system peak (at the time of this filing) on each island the Companies serve: O'ahu: 25.6%; Hawai'i Island: 33.8%; Maui: 40.2%; Moloka'i: 51.0%; Lana'i: 15.8%.[11]

To the extent that customers that fall within these extended program capacity limits are not able to or not allowed to interconnect for technical or operational reasons, or decide on a voluntary basis to no longer participate in the NEM program (including

[11] Please see Appendix 4, attached to this Motion, for a description of the calculations to develop these proposed percentage of system peak program capacity

moving to an alternative program such as the community solar or non-export program options currently under development), the percentages, which will be based on each island's system peak at the time of the filing of this Motion, will be reduced in a corresponding fashion. This is consistent with the goal of transitioning customers to DG 2.0 and more cost effective distributed renewable energy options rather than continuing to subscribe to the existing NEM program. The Companies respectfully submit that once the new program capacity is met, or by March 20, 2015, whichever occurs first, the Commission should determine that the Companies are no longer obligated to provide net energy metering to customer generators in their service areas and the NEM program should be declared closed.

Consistent with this, once these revised program capacity is met, or on March 20, 2015, the Companies will no longer accept new applications for the NEM program. This would include expansion of any existing NEM system. After program capacity is met or March 20, 2015, NEM program applicants and existing NEM program customers seeking to expand their system will be directed to the TDG.

5. Customer Transition Process

As the Companies move forward in transitioning away from the existing NEM program, the Companies have also developed a proposal to address both existing NEM program participants and those customers that are presently awaiting approval for interconnection under the existing NEM program. The Companies respectfully propose that:

(1) interconnected NEM program participants will continue under the existing NEM program structure subject only to any modifications that the Commission may approve as a part of the development, evaluation and approval of DG 2.0;

(2) customers who were awaiting approval for interconnection on O'ahu, Maui, Lana'i, Moloka'i and the island of Hawai'i as of October 22, 2014, will be eligible for the existing NEM program structure subject to any modifications that the Commission may approve as a part of the development, evaluation and approval of DG 2.0. These customers will be interconnected pursuant to the terms and conditions set forth in the Companies' October 31, 2014 Supplemental Responses to Commission Information Requests filed in Docket No. 2014-0192 which are as follows:

(a) The system to be interconnected must use inverters which have been tested for transient overvoltage to the satisfaction of the Hawaiian Electric Companies or certify compliance of performance using a Company-approved test plan; and

(b) The customers and solar companies performing the installations accept, as a condition of interconnection, the commitment and responsibility to upgrade the settings on their equipment from interim low voltage and frequency ride-through settings to final settings once UL certification of those final settings are obtained for their inverters. The reprogramming of the inverter settings shall be performed by the inverter manufacturers or installers at their expense. In addition, applications will still be subject to any other requirements identified in the Rule 14H screening process.

(3) customers who were not included within the queue for each island system as of October 22, 2014, but who apply for interconnection within any revised program

capacity approved by the Commission or by March 20, 2015, whichever occurs sooner, will be eligible for the existing NEM program structure subject to any modifications that the Commission may approve as a part of the development, evaluation and approval of DG 2.0. These customers will be interconnected as circuit and system constraints allow and pursuant to the requirements set forth in the Companies' October 31, 2014 correspondence and discussed above.

Additionally, and as discussed above, stakeholders in various Commission proceedings are presently discussing the availability of a variety of DG operational capabilities, including in particular power output control, which may be required of interconnecting systems in the future upon receipt of any necessary Commission approvals. Operational capabilities and overall support of grid reliability can be discussed as bases for prioritization of resource interconnection in the future.

Customers who are not eligible for the existing NEM program due to such factors as inability to fulfill their obligations under the existing NEM program; inability to be interconnected pursuant to the applicable requirements contained in the Companies' October 31, 2014 correspondence, a lack of program capacity due to revised program capacity levels having been met for the system the customer is seeking to interconnect to, or the occurrence of the March 20, 2015 program conclusion date, may apply for the TDG program.

D. Approve An Interim Transitional Distributed Generation Tariff To Be Made Available To Customers.

As discussed extensively in the DGIP, the Companies recommend a progression away from the current NEM program and other programs toward a system that provides more customer choice, lower energy costs, and increased access to sustainable renewable resources. The Companies have recommended as a part of this transitional process that the new DG 2.0 consider and incorporate a number of provisions which could include development of revised rates based upon new methodologies and assumptions, rate design that could include implementation of time-variant elements, and curtailment policies and crediting schedules to equitably compensate customers during curtailment events. While the Companies hope to develop these alternative structures and processes in an expedited manner, they also recognize that addressing and working through such complex issues may take some time.

With the reintroduction of an appropriate NEM program capacity to the NEM program, alternative and more sustainable program options should be made available to customers whose proposed generation is in excess of the NEM program capacity approved by the Commission. The Companies propose that the Transitional Distributed Generation Program tariff described in more detail below be made available to customers on an interim basis until DG 2.0 can be developed with stakeholders and approved in this proceeding, or until January 1, 2017, whichever occurs sooner. To the extent that the collaborative development of DG 2.0 has not been completed within this approximately 2 year interim TDG program window, the parties to this proceeding may discuss and evaluate whether an extension of the TDG program, and any modifications to the program, may be required and recommended to the Commission for consideration. Interconnection of DG projects will be subject to Company engineering review to ensure that continued interconnections will not unacceptably reduce system reliability or increase costs for customers.

1. The TDG Should be Approved on an Interim Basis.

Through Exhibit A, the Commission made clear that the pricing of utility services should reflect new business and technical realities in Hawai'i. The Commission stated:

> *Current electric utility rate structures in Hawaii are not well suited for a future environment where there are significant quantities of variable renewable energy, customer-sited distributed energy resources and increasingly smart- grid technologies. Existing utility rate and pricing structures need to be reconsidered to better respond to customer and technological changes. In addition, current rate structures do not provide the correct market signals to customers and market actors to address periods with an excess supply of energy to the grid. In this area, the Commission offers the following perspectives for consideration: "Unbundled" rate structures could more appropriately fit customer preferences for varying levels of electricity service- Today, typical electric rate tariffs contain a bundled rate (price) to recover the cost of providing both utility electricity supply and energy delivery services. Unbundled rates that separate power supply, ancillary services, and energy delivery costs could more properly account for utilizing different mixes and quantities of various utility services where each customer would be charged accordingly. Customers with distributed generation are likely to utilize different combinations of utility-supplied electricity and grid-delivery services than customers without distributed generation. Under this structure, DER customers would pay for grid services they utilize and receive compensation for various grid support services they provide. An unbundled rate structure could also prevent shifting utility fixed costs from customers with distributed generation to customers without distributed generation, consistent with cost causation principles. (at page 25)*

(Emphasis supplied)

The NEM program has been extremely successful in encouraging the adoption of customer-sited DG and helping a nascent solar industry develop to a point where customer –sited DG has become more mainstream. TDG, as an interim measure, is required to address the cost and fairness issues associated with the existing NEM program while a more comprehensive effort to address the broader issues associated with distributed generation resources is undertaken in this proceeding.

The proposed TDG, a copy of which is attached to this Motion as Appendix 2, is an interim program which will provide a more sustainable alternative to the NEM program. The key attributes of the TDG are:

(1) New DG customers are charged separately for the energy that they consume at the tariff energy rates for their customer class. This helps ensure that they will be contributing a fairer share of the cost of the services they receive since there is a contribution to fixed costs embedded in the tariff energy rates;

(2) New DG customers will receive an energy credit for excess DG energy exported to the utility grid at a rate equal to the sum of the unbundled Base Fuel Energy Charge and the Energy Cost Adjustment rates. The energy credit rate for the January 2015 period would have been 14.6712¢/kWh for O'ahu; 18.6177¢/kWh for Hawai'i; 22.2996¢/kWh for Maui; 27.5688¢/kWh for Lana'i; and 26.2058¢/kWh for Moloka'i. These rates are consistent with the Commission's above-stated inclination toward the unbundling of rates while providing sufficient energy credit to incentivize investment in renewable DG with an estimated payback period for a 5 kW PV DG system that ranges from 5 years to 9 years.[12] Although reflecting only the fuel component of the retail rate,

---

[12] Assumes an installed price of $4.70 per watt, 17% capacity factor, 30% Federal income tax credit, 35% Hawai'i State income tax credit up to $5,000 per residential installation, 15% coincident "behind the meter" residential consumption of self-generation and energy credit rates equal to the simple average of the monthly base fuel plus energy cost adjustment rates that were effective from February 1, 2014 to January 1, 2015. A 5 kW PV system would cost approximately $11,450 after tax credits and the annual generation would be about 7,446 kWh/year. At the DG credit rate of 14.6712¢/kWh and effective retail rate of 29.4883¢ for O'ahu, the annual energy credit would be $1,258/year. The PV system cost of $11,450 divided by $1,258/year = 9.1 years. At the DG credit rate of 27.5688¢/kWh and effective retail rate of 40.0150¢/kWh for the island of Lana'i, the annual energy credit would be $2,192/year. The PV system cost of $11,450 divided by $2,192/year = 5.2 years.

If the February 2014-January 2015 average rates were used, the payback periods range from 5 to 7 years. At the average DG credit rate of 18.671¢/kWh and average effective retail rate of 33.507¢/kWh for Oahu, the annual energy credit would be $1,556/year. The PV system cost of $11,450 divided by $1,556/year = 7.4 years. At the average DG credit rate of 31.882¢/kWh and average effective retail rate of 43.723¢ for the island of Lana'i, the annual energy credit would be $2,478/year. The PV system cost of $11,450 divided by $2,478/year = 4.6 years.

Installed price of $4.70 per watt is the 2013 national median price for systems less than 10 kW per Barbose, G., Weaver, S., Darghouth, N., 2014, "*Tracking the Sun VII, An (sic) Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2013*", Lawrence Berkeley National Laboratory. SunShot, U.S. Department of Energy.

the rate for Oahu was still higher than the retail rates of all but 7 of the 171 North American domestic investor-owned utilities listed in the EEI July 1, 2014 Rankings report.[13] Furthermore, it better supports fairness to non-participants and more clearly delineates between energy delivered and received, and fixed and non-fixed charges;

(3) Similar to the NEM program, TDG customers will receive an energy credit to offset energy charges on their monthly bills, and any excess energy credits in a month will rollover with a 12-month reconciliation period; and

(4) Similar to the NEM program, TDG customers will be able to offset usage with self-generation behind the meter. This encourages TDG customers to shift electricity usage to periods of excess DG either coincidently or through battery storage.

The Companies maintain that the TDG should be approved to encourage more efficient customer utilization of DG resources and to address the fairness and cost allocation issues discussed through this Motion.

2. The Standard Form TDG Contract Should be Approved.

In order to implement the TDG program, a new standard form contract is required. This proposed Transitional Distributed Generation Tariff Standard Power Purchase and Interconnection Agreement (100 kW or less) ("TDG Agreement") will be utilized for those customers seeking to participate in the TDG program. A copy of the proposed TDG Agreement is attached hereto as Appendix 3.

17% capacity factor is the rounded average of PV Benchmarking factors per Attachment 4, pg. 37 of 135 *Docket 2008-0273 Feed-In Tariff ("FIT") Proceeding, Comments on Alternative FIT Tariff and Standard Agreement*, filed January 21, 2010.

[13] Edison Electric Institute, 2014, "Rankings July 1, 2014, pages 85-89.

In developing the TDG Agreement, the Companies utilized the form NEM Agreement as the baseline agreement. Where applicable, the Companies modified the existing NEM Agreement provisions to conform to the requirements of the TDG program and, where appropriate, added provisions to address certain deficiencies in the current NEM Agreement. The intent of this effort is to incorporate the required functionalities and technical requirements that will allow all distributed DG moving forward to reduce negative impacts on system reliability from variable DG resources. Where provisions were added, the Companies primarily utilized existing provisions from the existing form Standard Interconnection Agreement and Feed-in Tariff agreements which have been previously approved by the Commission.

The following is a summary of the notable modifications between the existing NEM Agreement and the proposed TDG Agreement:

- Paragraph 1: Notice Regarding Future Rate and Tariff Modifications. Requires the Customer-Generator to acknowledge, in writing, that the rules relating to the interconnection of their Generating Facility, including rules relating to required system controls, electricity rates, charges, and fees, are subject to future modification, including with appropriate Commission review and approval where necessary, and that such modifications may positively or negatively affect potential savings or the expected value of their DG system.

- Paragraph 2: Effectiveness of Agreement. Clarifies that: (1) the TDG Agreement shall not be effective until approved and executed by each Party, i.e., upon the Effective Date; (2) the Generating Facility shall not be operated in parallel with the Company's system prior to approval and execution of the TDG Agreement by the Company; and (3) any actions taken by a Party in reliance on the terms of the TDG Agreement prior to the Effective Date shall be at that Party's own risk.

- Paragraph 6: Parallel Operation. Reiterates that parallel operation of the Generating Facility is permitted in accordance with terms and conditions of the TDG Agreement and Company Rule 14, Paragraph H (Interconnection of Distributed Generating Facilities Operating in Parallel With The Company's Electric System) ("Rule 14H").

- Paragraph 8: Installation: Clarifies requirements for appropriate control and protection equipment, including requirements for automatic and manual disconnect devices.

- Paragraph 9: Metering. Clarifies that Company shall install required meters within fifteen (15) days of the Effective Date of the TDG Agreement.

- Paragraph 10: Purchase of Energy by Company and Exhibit E (Company's Payment Obligation): Sets forth the proposed compensation structure for TDG program participants. The TDG would function similarly to the existing NEM program in that there would be a monthly rollover of Energy Credit with a 12-month reconciliation period. In each billing period, the Energy Credits delivered by the Generating Facility during such billing period shall be credited against the cost of the Customer-Generator's kWh consumption, i.e., energy delivered by the Company to the Customer-Generator for such billing period under the applicable rate schedule ("Consumption Costs"). The Energy Credit to be applied would be equal to the Base Fuel Energy Charge plus the ECAC rate. Energy Credits will not be credited against the Minimum Charge or any other applicable fixed charges for the billing period.

- Paragraph 12: Indemnification. Clarifies indemnification obligations for Owners/Operators of Generating Facilities and makes formatting modifications to clarify indemnification obligations for governmental entities.

- Paragraph 13: Continuity of Service and Paragraph 14: Personnel and System Safety. Clarifies the conditions under which the Companies can temporarily disconnect, curtail, interrupt or reduce deliveries of energy.

- Paragraph 18: No Material Changes to Generating Facility. Clarifies that no material changes or additions to the Generating Facility, regardless of the size of the Generating Facility, can be made without first obtaining Company consent.

- Paragraph 21: Force Majeure: Clarifies that if a Force Majeure Event prevents a party from fulfilling any obligations under the TDG Agreement, the affected party will be entitled to suspend or modify its performance of obligations under the TDG as long as certain conditions are met.

- Paragraph 22: Good Engineering Practice: Provides that each party agrees to install, operate and maintain its respective equipment and facilities and to perform all obligations required to be performed by such party in accordance with good engineering practice in the electric industry and with applicable laws, rules, orders and tariffs.

- Paragraph 23(a): Disconnection and Survival of Obligations: Clarifies that Generating Systems under the TDG program shall be disconnected upon termination of the TDG Agreement and states that termination of the TDG Agreement shall not relieve either Party of their respective liabilities and obligations, owed or continuing at the time of termination.

- Paragraph 24: Provisions Applicable Only To Generating Facilities Greater Than 10 kW. Sets forth provisions that are only applicable to Generating Facilities with a Total Rated Capacity greater than 10 kW but not exceeding 100 kW.
- Appendix B (Description of Generating Facility): Formatting adjustments were made for clarity and ease of use.

This modified standard form agreement will both streamline and make more efficient the contracting for TDG program resources, and will provide for the required functionalities and technical requirements that will allow all distributed DG moving forward to contribute to grid reliability.

E. Energy Credits Under the TDG Should Be Offset to Revenues

Presently, under the NEM program, electric sales revenues and kWh sales are accounted for and reported on a net basis. The Companies propose a similar methodology for TDG. Energy credits and the associated kWh's received from customers under TDG would offset electric sales revenues and kWh sales, respectively. The major difference between the accounting for the TDG and NEM programs is that the energy credit under the TDG will be a factor of the base fuel and Energy Cost Adjustment ("ECA") rates rather than full retail rates under NEM. Under the TDG, the kWh's received from DG customers will offset kWh's delivered to DG customers and kWh sales will be reported on a net basis in a similar manner as the NEM program. The ECA reconciliation will use the net ECA revenues in its calculation as it does today under the NEM program. The Revenue Balancing Account ("RBA") adjustment will continue to use net kWh sales in its calculation of base fuel and purchased energy which is consistent with the current procedure for NEM. However, unlike NEM, TDG will not reduce base non-fuel revenues and, therefore, result in lower RBA adjustment revenues and lower customer bills than otherwise would result under NEM.

This procedure will facilitate an orderly program transition by utilizing existing processes. In addition, the Public Benefit Fund, Renewable Energy Infrastructure, Integrated Resource Planning and any other surcharges based on kWh sales will be appropriately collected since those surcharges will not be offset under TDG.

F. The DER Docket is the Appropriate Proceeding for This Request.

Through Order No. 32053, the Commission concluded that based on the Commission's observations and perspectives, "further information and analysis is necessary in order to analyze potential constraints that exist due to high penetration of solar PV systems, and as a result, develop strategies and plans to mitigate these constraints." The Commission therefore, ordered the Companies to file a Distributed Generation Interconnection Plan with the commission within 120 days of the date of Order No. 32053. The Companies' DGIP was filed for the Commission's consideration on August 26, 2014 and contained the Companies' proposals for a transitioning of the NEM program and development of an interim form of renewable energy tariff until the Companies and stakeholders could develop, and the Commission could approve, DG 2.0. On September 12, 2014, the Commission issued Order No. 32292 transferring the DGIP from Docket No. 2011-0206 to the instant proceeding. The Commission stated:

- *In Docket No. 2014-0192, the commission will address the technical, economic, and policy issues associated with distributed energy resources as they pertain to the electric operations of HECO, HELCO, MECO, and the Kauai Island Utility Cooperative ("KIUC"). Given the scope of Docket No. 2014-0192, the commission finds that it is appropriate to conduct the review of the DGIP in that Docket. Thus, the commission is hereby ordering the transfer of the DGIP from Docket No. 2011-0206 to Docket No. 2014-0192 for review.*

Accordingly, the Companies respectfully submit that this proceeding is the appropriate proceeding in which to evaluate and consider the Companies' Motion and related distributed generation issues.

G. Modifications to Rule 14H Will Be Required On A More Expedited Basis for a More Diverse and Advanced Grid.

As the Commission is aware, there are presently certain modifications to Tariff Rule 14H that have been submitted in Docket No. 2011-0206 via stipulation of the stakeholders. There are also proposed modifications that are in the process of being evaluated in Docket No. 2014-0130. There is a consensus that as variable DG has become in aggregate the largest single source of energy on the power grids, and as operational and technical requirements are identified based on the impacts of distributed resources, and as new technologies and functionalities become available to address these impacts, modifications to the Companies interconnection rules (Rule 14H) will also likely need to be instituted on a more expedited basis to have relevance. This includes means to evaluate interconnection requirements based on aggregate impacts on the entire power system and area networks, as well as individual circuit requirements.

Pursuant to the Commission's Ordering Paragraph 6 in Order No. 30027, issued December 20, 2011 in Docket No. 2010-0015, the Companies are required to submit a full Application to request approval of modifications to Rule 14H rather than the more expedited process provided by Rule 6-61-111 of the Commission's Rules of Practice and Procedure, Title 6, Chapter 61, HAR. In order that the Companies may be able to propose and seek approval of future modifications to Rule 14H, including any modifications needed to implement the requests and provisions discussed in this Motion (identification of which is anticipated to be conducted through transparent discussions with stakeholders), in a timely manner, the Companies respectfully request the Commission's approval to propose any further required modifications to Rule 14H through a 30-day notice filing provision pursuant to Rule 6-61-111, HAR.

H. The Companies Request an Expedited Decision on this Motion.

The Hawaiian Electric Companies respectfully submit that this Motion, the Memorandum in Support of Motion attached hereto, the supporting documentation provided or referenced herein, any opposition or comments provided by the parties to this proceeding, and any reply which may be approved by the Commission, will provide a sufficient record for the Commission's decision making on the requests made in this Motion. However, to the extent that the Commission may determine that additional process or information is required prior to decision making, the Companies stand ready to actively participate in such process as necessary.

As discussed above, on October 31, 2014, the Companies submitted their supplemental responses to the Commission's information requests in this proceeding describing the Companies' plans to interconnect the majority of customers in the NEM queue as of October 22, 2014, by April 2015, and all remaining customers in this grouping by December 2015. Through that correspondence, the Companies noted that as they continue to seek technical solutions for higher levels of DG PV adoption, the Companies will seek economic and policy solutions to ensure that all customers receive the benefits of more cost effective and grid friendly distributed renewable resources.

This includes a process for moving to a more sustainable distributed renewable generation procurement program which will allow the Companies to implement requirements which will support both circuit and system resiliency and reliability on a going forward basis. The Companies are not able to implement some of these technical requirements for NEM program customers due to existing statutory provisions which currently preclude the imposition of required controls upon these resources.

Due to the critical nature of these issues, the unconstrained level of the current NEM program and its associated economic, technical and equity impacts, and the need to implement more sustainable solutions, the Companies respectfully request that any Commission order on the requests presented in this Motion be issued on an expedited basis so that these program modifications and elements can be made available as soon as possible and within sixty days of this filing (i.e., by March 20, 2015) at the latest.

III. CONCLUSION

Hawai'i's high DG penetration is unmatched by any other utility in the nation. DG growth in the islands has benefitted DG customers, lowering their bills and increasing their choices and control over their energy use. It has brought jobs and innovation to the growing energy industry in Hawai'i, and it has provided a valuable source of renewable energy to the grid, while contributing to environmental goals across the islands. However, the current policies governing DG have also created cost and allocation issues for the Companies and their full-service customers.

In evaluating the requirements needed to increase the amount of DG that can be supported, the current NEM program and rate structure, which increasingly adversely impact non-NEM customers, have become unsustainable. The NEM program, which compensates customers for energy exported onto the grid by DG systems at full retail rates, allows DG customers to shift the burden of operating the grid to full-service customers, while still benefiting from access to the grid's physical infrastructure for import and export of power - with many NEM customers paying less than their cost for services they receive from the utility. By the end of 2014, the annualized shift in the burden of fixed costs from DG to full-requirements customers due to the NEM program totaled approximately $53 million across all islands. This cost shift has the potential to increasingly affect customer bills in future years as DG capacity grows.

In addition, the system capacity taken up by the NEM program can supersede the integration of other renewable procurement programs that cost less and benefit all customers – both NEM and non-NEM customers – contrary to recent directives from the Commission. From the perspective of total system production cost, high levels of DG under the NEM program are more expensive to install and operate than utility-scale renewable energy. The need for significant investment in grid modernization has also increased, in part because of the impact of distributed resources on the grid.

In addition to these cost and allocation challenges, the interconnection process has not facilitated consideration of the aggregate impacts of DG on system reliability in its requirements. DG, in aggregate, is one of the largest suppliers of energy to the power systems. The impacts of DG, due to their operational and technical characteristics, have created significant system level operational challenges and reliability impacts. High levels of uncontrolled, unscheduled, and variable energy from DG systems are an increasing threat to the safety and reliability of the power network at the circuit and system levels. In response to circuit-level impacts, the Companies have been forced to restrict the interconnection of DG on certain circuits with high existing levels of DG, leading to a significant reduction in the rate of interconnections and an increase in customers waiting in interconnection queues while technical solutions could be verified.

Restrictions on DG interconnections, in turn, have created an unpredictable business environment for external stakeholders, including the Companies' partners in the solar industry.

As discussed in the DGIP, the Companies propose transitioning the NEM program to a more equitable and sustainable rate mechanism under DG 2.0 through the regulatory process which will take place in this docket in due course. Under revised tariff structures, DG 2.0 will enable the interconnection of export and non-export systems in a manner that more fairly and appropriately compensates DG providers. In the short term, these policies entail transitioning the NEM program to an interim DG procurement tariff, or TDG.

This proposed TDG provides for a new rate solution that is reasonable, and reduces cross-subsidization issues for non-participants. The proposed approach addresses the Commission's request for cost allocation methods that allocate costs to the customers who bear responsibility for system and circuit upgrade costs. The TDG compliments the commitment by the Companies to provide a range of options for accessing distributed generation resources, including dispatchable ("export") DG systems, non-export systems, and community solar alternatives. The TDG is an interim and transitional tariff until DG 2.0 can be developed with stakeholder input in this proceeding.

Accordingly, the Companies respectfully request through this Motion that the Commission: (1) reinstitute an appropriate program capacity level for the Companies' existing NEM program, (2) approve the Companies' proposal to address both existing NEM program participants and those customers that are presently awaiting approval for interconnection under the existing NEM program; (3) approve an interim transitional distributed generation tariff to be made available to all customers, including any customers whose proposed generation is in excess of the program capacity approved by the Commission; and (4) approve the standard form TDG contract to be utilized on an interim basis for those customers seeking to participate in the TDG program; (5) reinstate the Companies' ability to submit proposed modifications to Tariff Rule 14H via a 30-day filing pursuant to Rule 6-61-111, HAR; and (6) grant such other and further relief as the Commission may deem appropriate under the circumstances discussed herein.

The Companies respectfully submit that having provided good cause and grounds therefore, that the Commission approve the instant Motion and grant the relief requested herein within sixty days, or by March 20, 2015, at the latest.

A hearing on this Motion is not requested. To the extent that any comments are submitted pursuant to H.A.R. 6-61-41 in response to this Motion, the Companies respectfully request the Commission's authorization to file a reply within 10 days of the receipt of such comments for purposes of supplementing the available record for the Commission's decision making

Dated: Honolulu, Hawai'i, January 20, 2015

ROD S. AOKI
Attorney for
Hawaiian Electric Company, Inc.
Maui Electric Company, Limited
Hawai'i Electric Light Company, Inc.

Justification for 250% of GDML

In the interconnection process, which is described in the Hawaiian Electric Companies' Rule 14H[1], the application for interconnection would first undergo an Initial Technical Review. If one or more of the Initial Technical Review screens are not passed, the application would then undergo a Supplemental Review. If one or more of the Supplemental Review screens are not passed, a determination may be made that an Interconnection Requirements Study ("IRS") is required.[2]

The Supplemental Review uses as one of the thresholds for the screening work a level of "50% of the Line Section minimum kW load during the period when the proposed generation is available (including noon on Sunday for solar photovoltaic systems)." [3] As the Hawaiian Electric Companies gained more insights on circuit performance and reliability through studies and actual experience, it gradually increased this threshold.

For example, on September 18, 2012, the Hawaiian Electric Companies announced that IRSs would not be required for Distributed Generation ("DG") (≤ 10 kW) systems that would be interconnected on circuits with penetration levels < 75% of Gross Daytime Minimum Load ("GDML"). On September 6, 2013, the Hawaiian Electric Companies announced that IRSs would not be required for DG (≤ 10 kW) systems that would be interconnected on circuits with penetration levels < 100% of GDML. On February 26, 2014, Hawaiian Electric issued a notice to the solar industry that IRSs would not be required for DG (≤ 10 kW) systems that would be

[1] For example, as provided in Hawaiian Electric's Rule No. 14 (Service Interconnections and Facilities on Customer's Premises), Appendix III (Interconnection Process Overview), on Revised Sheet No. 34D-1 to 43D-26.
[2] Pursuant to Order No. 32053 in this proceeding, the PV-DG Subgroup submitted on May 28, 2014, a Stipulation among the parties in this proceeding pertaining to modifications to Rule 14H. As indicated in the Order, "the commission intends to rule on the Stipulation in this docket." (Order at 61)
[3] For example, see Sheet No. 34D-17, paragraph d. in Hawaiian Electric's Rule No. 14.

interconnected on circuits with penetration levels ≤ 120% of GDML, provided that the PV systems utilize fast-trip inverters or automatic transfer switches for installations where the penetration level is ≥ 100% GDML and ≤ 120% of GDML.[4]

One concern with higher circuit penetration levels is with load rejection transient overvoltage. This can occur when excess generation capacity on a customer's secondary and distribution transformer suddenly has less load because the feeder breaker or another device opens; this mismatch of load and generation leaves the DG with too little load to absorb its energy. This situation reflects a temporary unintentional island for the customers served from the distribution transformer. In some situations, this condition can pose a threat to connected customer loads and utility equipment served from the same customer transformer.

To determine whether the circuit penetration threshold could be increased above 120% of GDML, Hawaiian Electric worked collaboratively with SolarCity and the Electric Power Research Institute to test certain inverters at the National Renewable Energy Laboratory in Golden, Colorado. The performance of each selected inverter was tested under controlled conditions to determine the extent to which overvoltage occurred and the speed at which inverters tripped off line when test circuits were suddenly islanded. Tests were conducted with increasing ratios of PV generation to circuit load.

In general, the test results indicated that there was a correlation between the level of overvoltage and increasing ratios of PV generation to circuit load, i.e., higher ratios of PV generation to circuit load resulted in higher levels of overvoltage when the circuit was suddenly islanded. The test results also indicated that the tested inverters could trip off extremely quickly to mitigate the extent to which overvoltage occurred.

---

[4] Please refer to the Hawaiian Electric Companies' responses to PUC-IR-1 to PUC-IR-4, submitted on March 21, 2014, via letter with Subject "Changes in Interconnection Procedures for Small PV Installations Announced January 30, 2014."

Exhibit 1 of this Appendix 1 provides a summary and explanation of the results.

The Companies' compared the results with the Information Technology Industry Council ("ITIC") (formerly known as Computer Business Equipment Manufacturers Association, or "CBEMA") curve, which limits various levels of high voltage over time to prevent damage to 120-volt customer equipment.

The Companies' made several observations from the results provided in Exhibit 1:

1. In general, the overvoltage magnitude and duration produced by inverters two through four fall narrowly outside of the ITIC curve, including up to 1,000% penetrations.
2. The overvoltage magnitude and duration produced by inverter one falls narrowly outside the ITIC curve except at higher penetration levels (i.e. > 300%).
3. Different inverter models have different transient overvoltage characteristics. Each model should be independently tested and not serve as a proxy for other inverter models.
4. Each inverter also produces different voltage waveforms, not typical 60Hz sinusoidal waveforms.
5. No load rejection test produced an overvoltage greater than 200% of nominal voltage.

The Companies' evaluation of the test results against the ITIC curve indicated that circuit penetration levels greater than 120% of GDML but less than some upper bound can be allowed such that load rejection overvoltage will occur in the non-prohibited region, or narrowly outside of the ITIC curve. In order to establish a new, higher upper bound, the Companies considered the following factors:

- The laboratory tests were conducted on inverters one at a time. Under actual field conditions, there may be hundreds of different models of inverters tripping off simultaneously in a load rejection scenario.
- Actual field conditions include dynamic loads and electrical components and equipment not simulated in a carefully controlled laboratory test environment. Data from a load rejection event occurring in field conditions is not well documented by the industry or by the Companies, as the NEM program continues to take distribution circuit penetrations to unprecedented levels.
- Actual experience should be obtained with gradually increasing penetration levels. Circuit monitoring will help identify issues as penetration levels are increased[5].

In consideration of the test results, the ITIC curve and the factors identified above, the Companies intend to increase the allowable threshold from 120% of GDML to 250% of GDML.

It should be noted that the circuit penetration level is not the sole factor that is used to determine whether a system can be interconnected to the distribution system. Systems will still be subjected to the screening process provided in Rule 14H, including Supplemental Reviews. Other issues at either the circuit level or the system level may arise and may need to be mitigated. The situation on Lana‘i and Moloka‘i may be particularly sensitive to system level issues as the total system load on these islands is substantially lower than on the larger islands. There may be issues with excess energy at the system level.

[5] DGIP, Attachment E-2, At 2-27

Summary of Results[6]

This Exhibit I illustrates the load rejection testing for the five inverters tested at the National Renewable Laboratory ("NREL") at various penetration levels. The results are reported by NREL as "total overvoltage duration" curves.

The total over-voltage duration curves for each of the five test inverters are provided below. These plots display the total amount of time that the voltage at the AC terminals exceeded each of the critical voltage thresholds (110%, 120%, and 140% of nominal voltage). Each measurement is inclusive of higher threshold limits; for example, time above the 120% threshold includes time above the 140%, 200%, and 500% thresholds. For three-phase inverters (Inverter 4 and Inverter 5), these plots show the total time that any of the three phases exceeded a given threshold (the sum of the three phases).

An example over-voltage duration plot is shown in Figure 3. The legend shows each of the 11 inverter power and load power test settings, and a plot is given at each of these test settings for each voltage threshold. The legend reads top to bottom as the plot points read left to right for each voltage threshold level. Each whisker plot shows the average (mean) value of the seven test runs, along with the maximum and minimum values of these tests. All time measurements are reported in milliseconds (ms), and only the 110%/120%/140% voltage thresholds are reported because no instantaneous voltage measurement exceeded the 200% voltage threshold.

[6] Graphs and text in Exhibit 1 are referenced from: *SolarCity CRADA Task 1 Interim Report: Load Rejection Over-voltage Testing."* Nelson, A., Hoke, S., Chakraborty, S., NREL. Golden, CO: December 2014. At 8-13.

Continuing with Figure 3, the 11th whisker plot from the left represents the test scenario of 67% inverter output power and 10% load power – 10% load represents 10% of the inverter nameplate rating. In other words, this scenario represents the 670% penetration. This specific whisker plot shows the maximum, average, and minimum total time (out of seven test runs) the resultant overvoltage remained over 110% of nominal voltage was approximately, 85, 64, and 53 milliseconds, respectively. At 85 milliseconds, the worst case or maximum overvoltage at the 110% threshold falls within the 0.5 seconds allowed at the 110% of nominal voltage threshold as indicated in the ITIC curve included in Exhibit 2 of this Appendix 1.

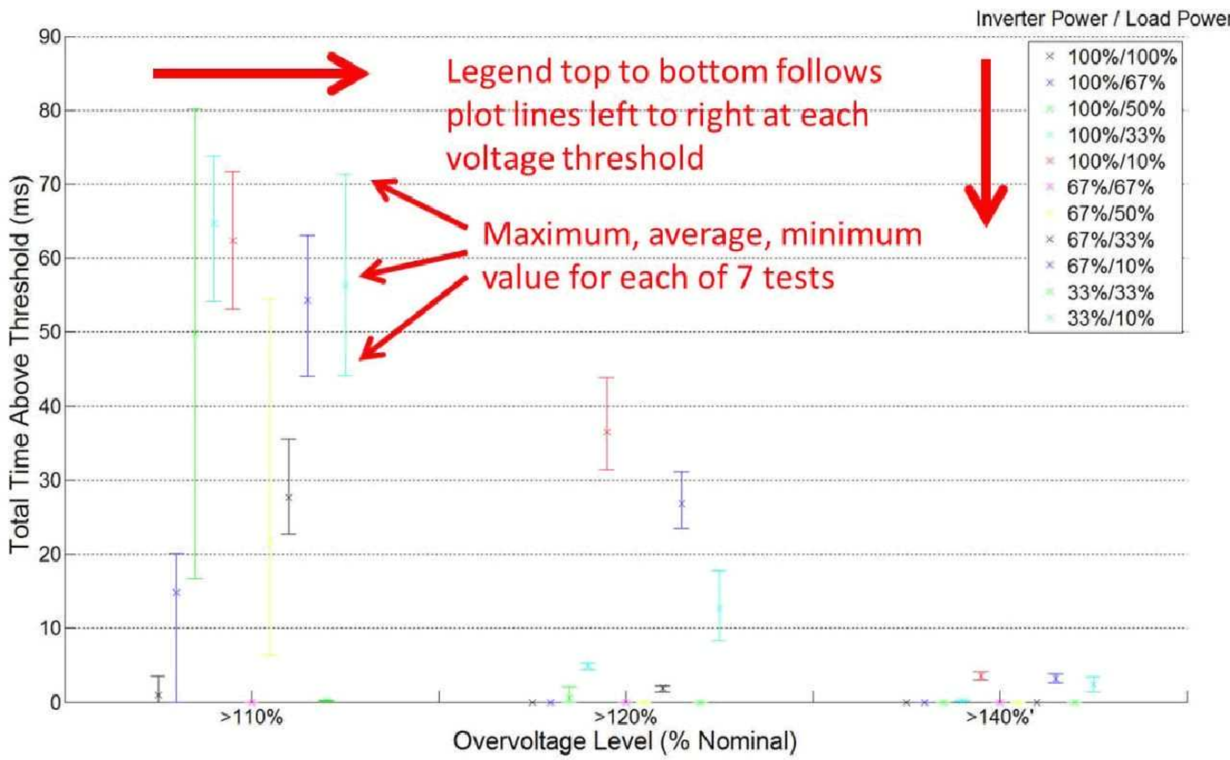


Figure 1 Example plot overvoltage duration as a function of voltage threshold level for a single test inverter

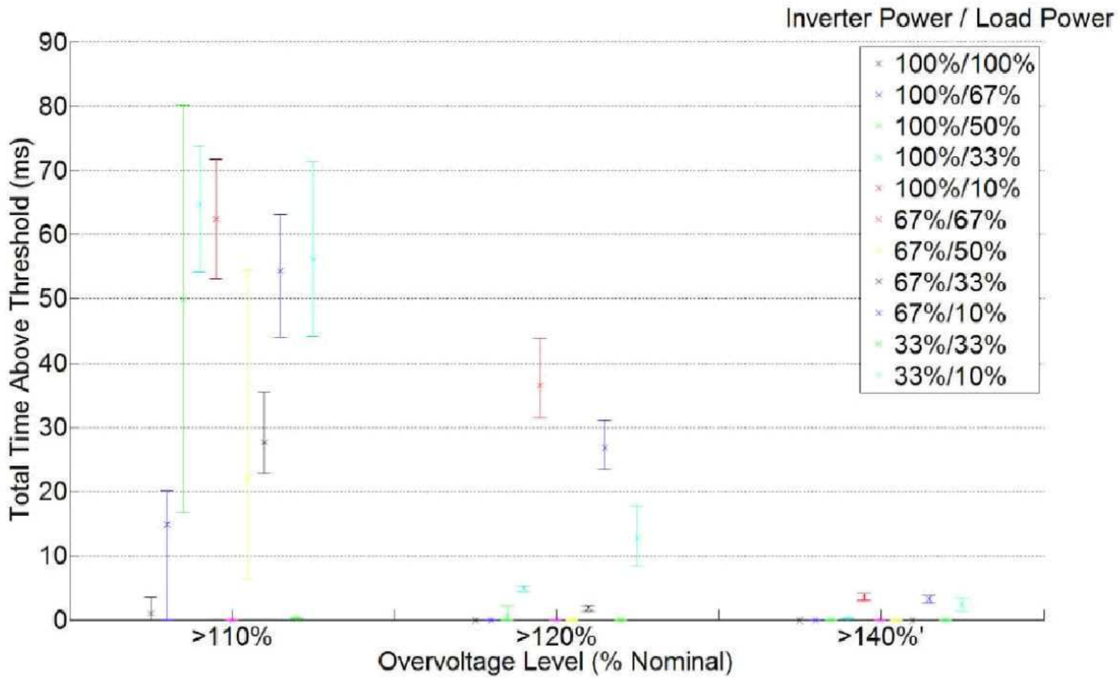


Figure 2 Overvoltage duration times for Inverter 1

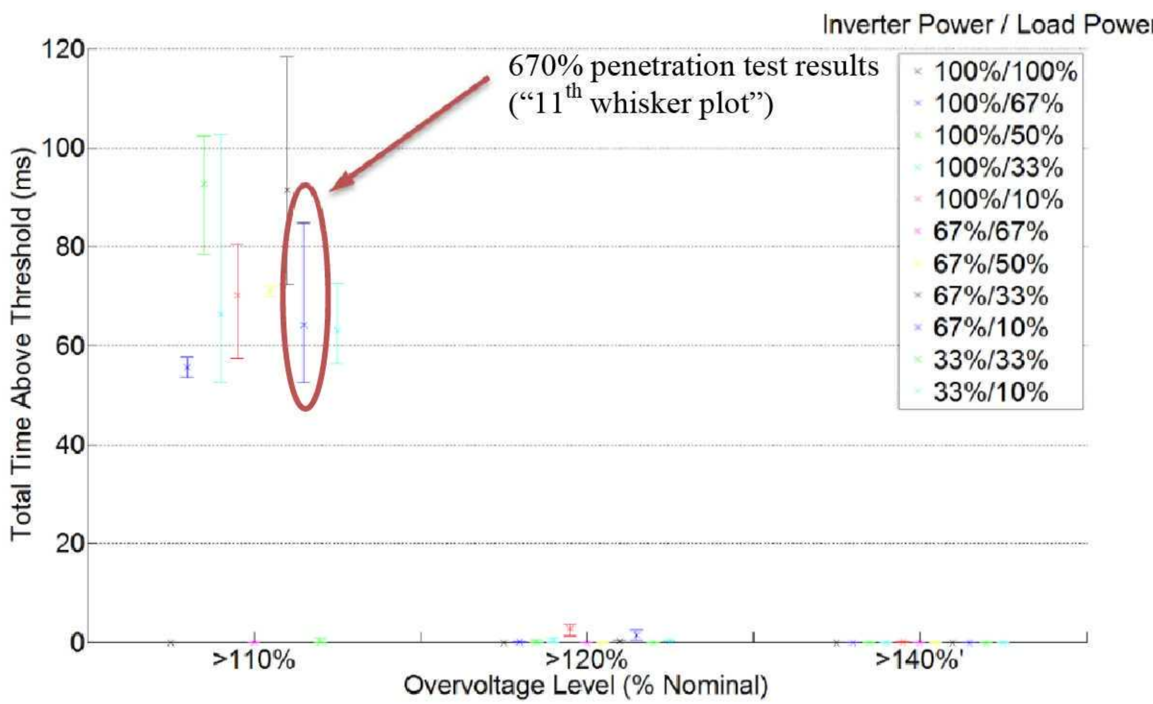


Figure 3 Overvoltage duration times for Inverter 2

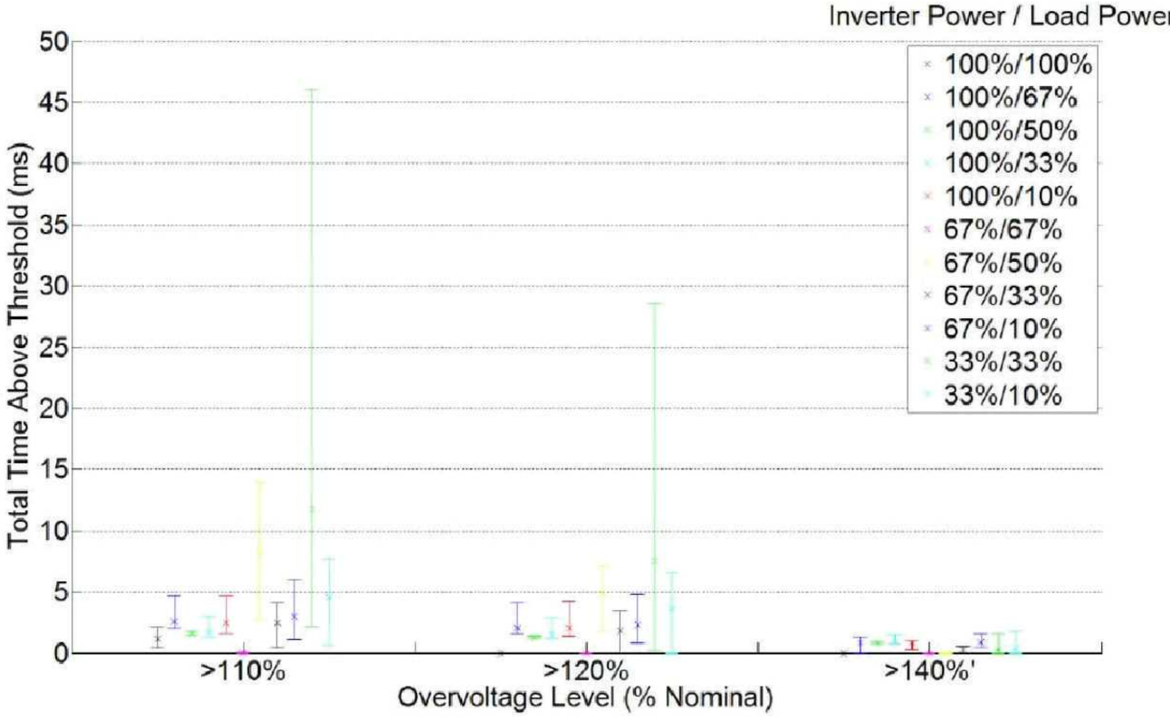


Figure 4 Overvoltage duration times for Inverter 3

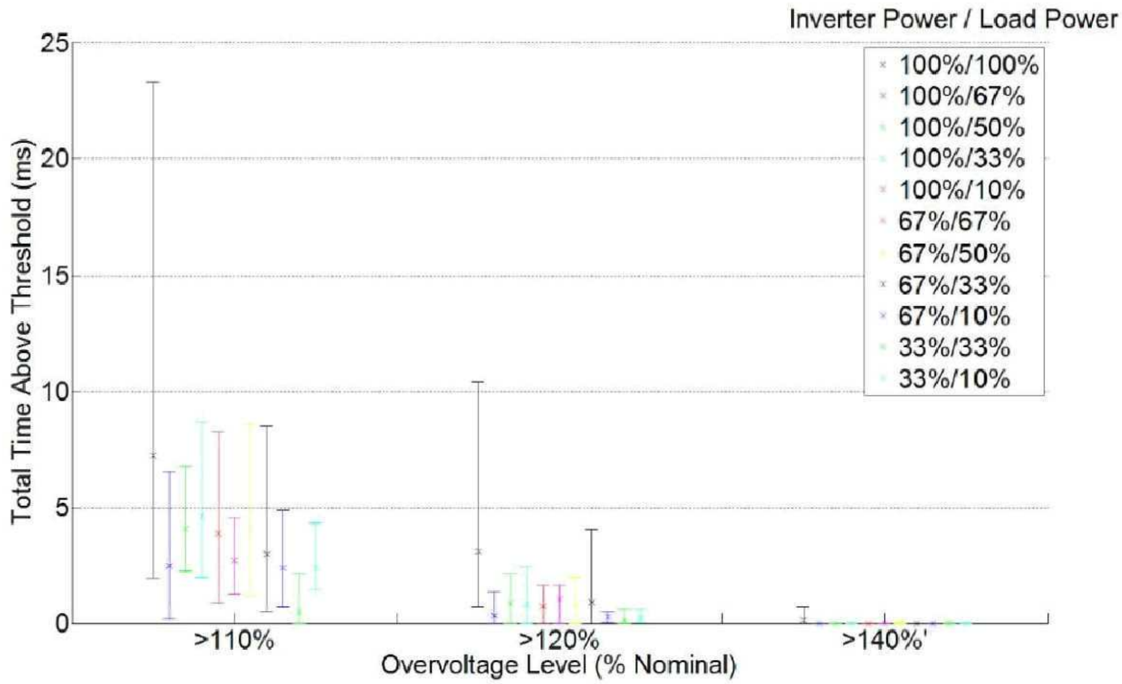


Figure 5 Overvoltage duration times for Inverter 4

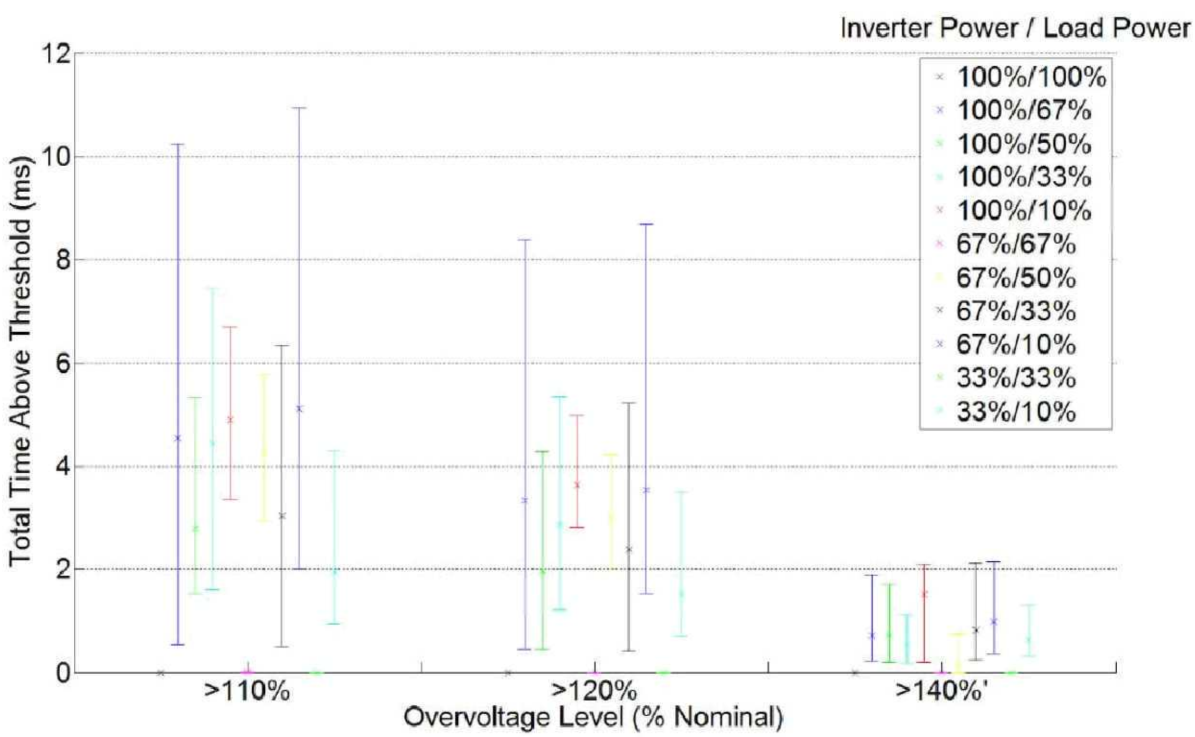
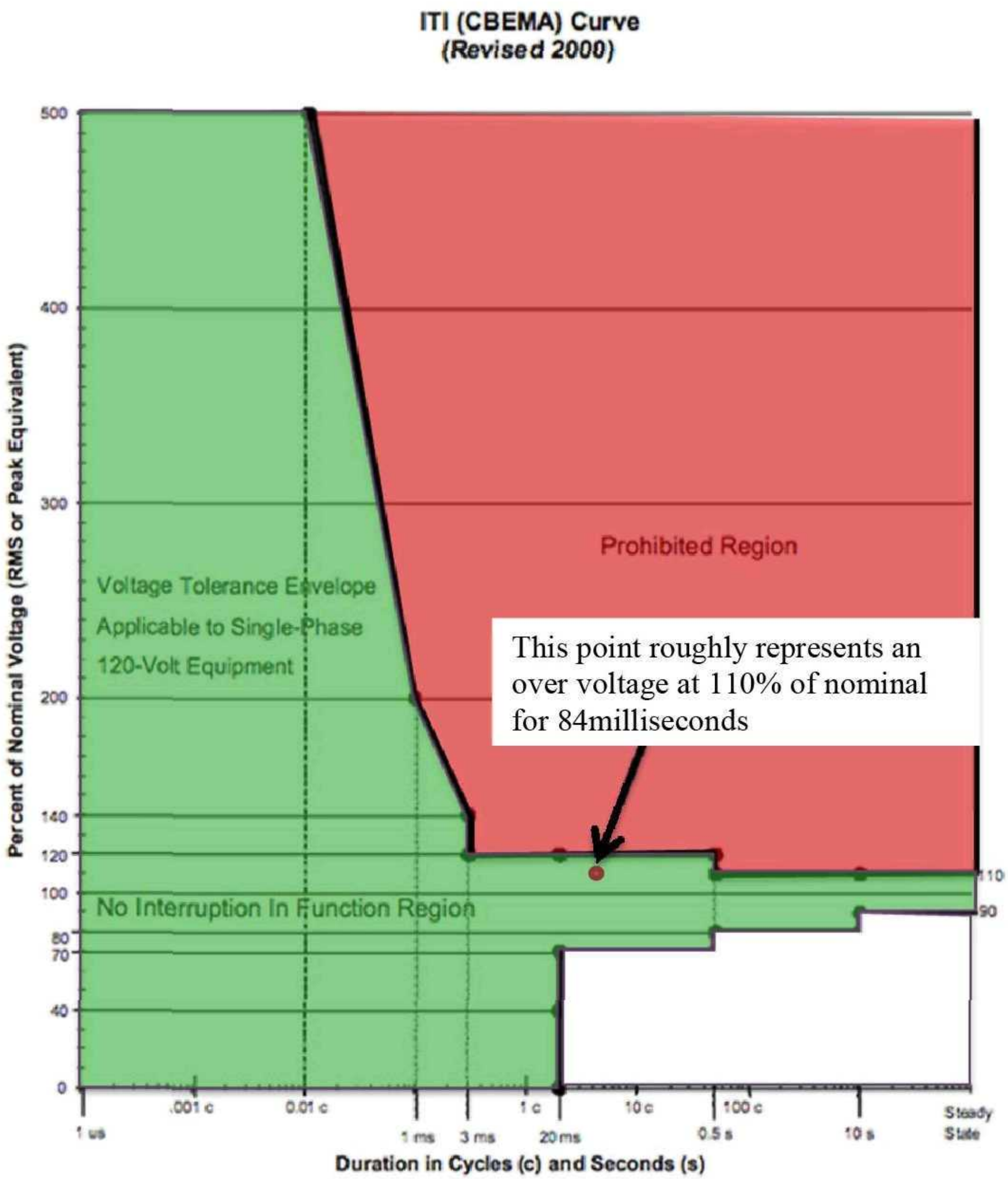


Figure 6 Overvoltage duration times for Inverter 5

ITIC Curve


ITI (CBEMA) Curve
(Revised 2000)
Prohibited Region
Voltage Tolerance Envelope
Applicable to Single-Phase
120-Volt Equipment
This point roughly represents an over voltage at 110% of nominal for 84milliseconds
No Interruption In Function Region
Percent of Nominal Voltage (RMS or Peak Equivalent)
500
400
300
200
140
120
100
80
70
40
0
110
90
1 us
.001 c
0.01 c
1 ms
3 ms
1 c
20 ms
10 c
100 c
0.5 s
10 s
Steady State
Duration in Cycles (c) and Seconds (s)

Transitional Distributed Generation Tariff

A. AVAILABILITY FOR CUSTOMER-GENERATORS

Transitional Distributed Generation service is available to permanent customers ("Customer-Generator") who own (or lease from a third party) and operate (or contract to operate with a third party) a solar, wind turbine, biomass, or hydroelectric energy generating facility, or a hybrid system consisting of two or more of these facilities ("Generating Facility"), with a capacity of not more than one hundred kilowatts (100 kW) that is:

1. located on the Customer-Generator's premises,
2. operated in parallel with the Company's transmission and distribution facilities,
3. in conformance with the Company's interconnection requirements provided in Rule No. 14, Section H, and
4. intended primarily to offset part or all of the Customer-Generator's own electrical requirements.

B. TRANSITIONAL DISTRIBUTED GENERATION STANDARD POWER PURCHASE AND INTERCONNECTION AGREEMENT

1. Customer-Generator shall complete and sign a Transitional Distributed Generation Standard Power Purchase and Interconnection Agreement, which shall not be effective until approved and executed by the Company. Where the Customer-Generator is not the person or entity in whose name electric service is rendered for the Customer-Generator's premises where the Generating Facility is located, i.e. where a landlord-tenant relationship exists, only the Customer-Generator shall be required to complete and sign a Transitional Distributed Generation Standard Power Purchase and Interconnection Agreement. Energy Credits may be applied to Customer-Generator's tenant's electrical service with written consent from the Customer-Generator.

2. The Customer-Generator's facility and interconnection systems must be in compliance with all applicable safety and performance standards of the National Electric Code (NEC), the Institute of Electrical and Electronic Engineers (IEEE), accredited testing laboratories such as Underwriters Laboratories (UL), the Company's interconnection requirements provided in Rule No. 14. Section H, Appendix I, and is subject to any other requirements provided in the Transitional Distributed Generation Standard Power Purchase and Interconnection Agreement.

SHEET NO. xx
Effective

Transitional Distributed Generation Tariff – Continued

C. METERING AND BILLING

1. The Company, at its expense, may install meter(s) to record the flow of electric power in each direction. The Customer-Generator shall, at its expense, provide, install and maintain all conductors, service switches, fuses, meter sockets, meter instrument transformer housing and mountings, switchboard meter test buses, meter panels and similar devices required for service connection and meter installations on the customer's premises in accordance with the Company's Rule No. 14, Section A.2.

2. Customer-Generators served under this tariff who also receive energy from the Company shall be billed monthly for the energy supplied by the Company, in accordance with the Company's Rule No. 8, the applicable rate schedule, and the Company's rules filed with the Commission.

   The measurement of the kWh supplied by the Company to the Customer-Generator and the kWh received by the Company from the Customer for the first bill of the initial 12-month reconciliation period shall begin on the date of installation of the required meter(s). Each subsequent 12 billing months shall represent the Customer-Generator's reconciliation period.

3. All kWh received by the company from the Customer-Generator shall be assigned a dollar value as Energy Credits. The Energy Credits earned for the billing period shall be calculated as the sum of the Base Fuel Energy Credits and the Energy Cost Adjustment Credits. The Base Fuel Energy Credits shall be the applicable Base Fuel Energy Charge rate in cents per kWh (from Schedule R) multiplied by the energy received by the Company from the Customer-Generator during the billing period. The Energy Cost Adjustment Credits shall be the applicable Energy Cost Adjustment Factor in cents per kWh multiplied by the energy received by the Company from the Customer- Generator during the billing period. When the Base Fuel Energy Charge and/or the Energy Cost Adjustment Factor change during the billing period, their values will be pro-rated in the calculation of the Energy Credits.

4. In each billing period, the Customer-Generator's available Energy Credits, including those earned for the billing period plus any Unused Energy Credits from the current 12-month reconciliation period shall be applied against the total of the electric bill calculated under the applicable rate schedule for the energy delivered by the Company to the Customer-Generator in the billing period. Such Energy Credits applied shall appear as a separate line item on the customer bill. Application of Energy Credits may only reduce the electric bill to an amount equal to the minimum charge for the applicable rate schedule plus any other applicable fixed charges for the billing period. Any Unused Energy Credits shall be carried forward to subsequent billing periods within the current 12-month reconciliation period.

SHEET NO. xx
Effective

Transitional Distributed Generation Tariff – Continued

5. At the end of each 12-month reconciliation period, a final reconciliation will be made for any remaining Unused Energy Credits. Unused Energy Credits will be applied to the excess of the total of the electric bill above the minimum charge plus any other applicable fixed charges for the 12-month reconciliation period. Any Energy Credits applied in this reconciliation shall be included with any applicable Energy Credits for the current billing month on the customer bill line item credit. Application of Energy Credits may only reduce the electric bill to an amount equal to the minimum charge plus any other applicable fixed charges in any billing period. Any Unused Energy Credits that are not applied in this final reconciliation shall be forfeited.

TRANSITIONAL DISTRIBUTED GENERATION TARIFF
STANDARD POWER PURCHASE AND INTERCONNECTION AGREEMENT

(100 kW or less)

This Transitional Distributed Generation Tariff Standard Power Purchase and Interconnection Agreement (100 kW or less) ("Agreement") is made by and between:

____ ("Company"),

____ ("Customer-Generator") and, if applicable,

____ ("Owner/Operator"),

and is made, effective and binding as of _____________________ ("Effective Date"). Company and Customer-Generator may be referred to individually as a "Party" and collectively as the "Parties".

WHEREAS, Company is an operating electric public utility subject to the Hawaii Public Utilities Law, Hawaii Revised Statutes, Chapter 269, and the rules and regulations of the Hawaii Public Utilities Commission ("Commission");

WHEREAS, the Customer-Generator receives permanent service from the Company;

WHEREAS, the Customer-Generator qualifies as an "Eligible Customer-Generator," as defined in the Company's Transitional Distributed Generation Tariff;

WHEREAS, the Customer-Generator intends to construct a generating facility, as further described herein ("Generating Facility") and desires to interconnect the Generating Facility in parallel with the Company's electric system and to sell to the Company electric energy generated by the Customer-Generator's Generating Facility under Company's Transitional Distributed Generation Tariff;

WHEREAS, the Company wishes to purchase such energy from the Customer-Generator upon the terms and conditions set forth herein;

WHEREAS, the Owner/Operator, may be a person or entity other than the Customer-Generator, who owns and operates the Generating Facility.

NOW, THEREFORE, in consideration of the premises and the respective promises herein, the Company and the Customer-Generator, and if applicable, the Owner/Operator, hereby agree as follows:

1. **<u>Notice Regarding Future Rate and Tariff Modifications</u>**. This Agreement shall, at all times, be subject to modification by the Commission as said Commission may, from time to time, direct in the exercise of its jurisdiction. Customer-Generator acknowledges that such modifications may positively or negatively impact any potential savings or the value of Customer-Generator's Agreement and Generating Facility.

CUSTOMER-GENERATOR SHALL ACKNOWLEDGE AND SIGN THE "NOTICE AND DISCLAIMER – POSSIBLE FUTURE RULES AND/OR RATE CHANGES AFFECTING YOUR GENERATING FACILITY" ATTACHED HERETO AS EXHIBIT A.

2. **Effectiveness of Agreement**. This Agreement shall not be effective until approved and executed by each Party, i.e. upon the Effective Date. Customer-Generator shall not interconnect and operate the Generating Facility in parallel with the Company's system prior to approval and execution of this Agreement by the Company, except to extent necessary to obtain governmental or utility approvals. Until this Agreement is effective, no Party shall have any legal obligations arising hereunder, express or implied, and any actions taken by a Party in reliance on the terms of this Agreement prior to the Effective Date shall be at that Party's own risk.

3. **Term and Termination.** This Agreement shall continue on a month-to-month basis from the Effective Date. Customer-Generator may terminate this Agreement at any time with thirty (30) days' written notice. Company may terminate this Agreement at any time if Customer-Generator fails to comply with any term of this Agreement or if Customer-Generator fails to be an Eligible Customer-Generator.

4. **Generating Facility Description**. For the purposes of this Agreement, the "Generating Facility" is defined as the equipment and devices, and associated appurtenances, owned by the Customer-Generator, which produce electric energy for use by the Customer-Generator and are to be interconnected and operated in parallel with the Company's system. The Generating Facility is identified in Exhibit B (Description of Generating Facility) attached hereto.

5. **Scope of Agreement**. The Parties understand and agree that this Agreement applies only to the operation of Customer-Generator's Generating Facility described in Exhibit B attached hereto.

6. **Parallel Operation**. Company shall allow Customer-Generator to interconnect and operate the Generating Facility in parallel with the Company's distribution system in accordance with the terms and conditions of this Agreement and Company Rule 14, Paragraph H (Interconnection of Distributed Generating Facilities Operating in Parallel With The Company's Electric System) ("Rule 14H").

7. **Permits and Licenses**. Customer-Generator shall be responsible for the design, installation, operation, and maintenance of the Generating Facility and shall obtain at its expense, and maintain any required governmental authorizations and/or permits for the construction and operation of the Generating Facility. Customer-Generator shall not commence parallel operation of the Generating Facility until Company has provided written approval. Company shall provide such written approval within thirty (30) business days from Company's receipt of a copy of the final inspection or approval of the Generating Facility, which has been issued by the governmental authority having jurisdiction to inspect and approve the installation. Company's written approval shall not be unreasonably withheld. Company shall have the right to have its representatives present at the final inspection made by the governmental authority having jurisdiction to inspect and approve the installation of the Generating Facility. Customer-Generator shall be required to notify Company in accordance with the terms of Section 18 (Notices), herein, at least five (5) business days prior to such inspection.

8. **Installation**.

(a) Design, installation, operation and maintenance of the Generating Facility shall include appropriate control and protection equipment as specified by the Company, including but not limited to an automatic load-break device such as a circuit breaker or inverter and a manual disconnect that has a visible break or breaker with rack-out capability to isolate the Generating Facility from the Company's system. The manual disconnect device must be accessible by the Company and be capable of being locked by the Company in the open position, to establish working clearance for maintenance and repair work in accordance with the Company's safety rules and practices. The disconnect devices shall be furnished and installed by the Customer-Generator and are to be connected between the Generating Facility and the Company's electric system. The disconnect devices shall be located in the immediate vicinity of the electric meter serving the Customer-Generator. The manual disconnect device shall be, at a minimum, clearly labeled "Customer-Generator System Disconnect". With permission of the Company, the disconnect devices may be located at an alternate location which is readily and safely accessible to the Company on a 24-hour basis. Such alternate location shall be clearly identified with signage placed in the immediate vicinity of the electric meter serving the Customer-Generator.

(b) The Customer-Generator grants access to the Company to utilize the disconnect device, if needed. The Customer-Generator shall obtain the authorization from the owner and/or occupants of the premises where the Generating Facility is located that allows the Company to access the Generating Facility for the purpose specified in this Agreement. Company may enter premises where the Generating Facility is located, as permitted by law or tariff, for the following purposes: (a) to inspect Generating Facility's protective devices and read or test meter(s); and (b) to disconnect the Generating Facility and/or service to Customer-Generator, whenever in Company's sole opinion, a hazardous condition exists and such immediate action is necessary to protect persons, Company's facilities, or property of others from damage or interference caused by the Generating Facility, or the absence or failure of properly operating protective device.

(c) Under no circumstances shall a Customer-Generator interconnect and operate a generating facility in parallel with the Company's electric system without prior written approval by the Company in the form of a fully executed Agreement.

(d) Generating facilities that incorporate the use of an energy storage device, e.g. battery storage, regardless of whether such energy storage device is intended to operate in parallel with the Company's transmission and/or distribution facilities, shall obtain an interconnection review by the Company pursuant to this Agreement. Energy storage systems that are intended to be installed by an Eligible Customer-Generator after Company's execution of an Agreement shall constitute a material change and addition to a generating facility and shall require interconnection review pursuant to this Rule prior to installation.

(e) Once a Generating Facility interconnected to the Company's system, the Company reserves the right to require the installation of, or modifications to, equipment determined by the utility to be necessary to facilitate the delivery of reliable electric service to its customers.

9. **Metering**. Within fifteen (15) days of execution of this Agreement, the Company will supply, own, and maintain all necessary meters and associated equipment utilized for billing and energy purchase. The meters will be tested and read in accordance with the rules of the Commission and the Company. The Customer-Generator, at its expense, shall provide, install and maintain all conductors, service switches, fuses, meter sockets, meter instrument transformer housing and mountings, switchboard meter test buses, meter panels and similar devices required for service connection and meter installations on the Customer-Generator's premises in accordance with the Company's Rule 14H.

10. **Interconnection Facilities**.

(a) **Customer-Generator-Owned Interconnection Facilities**.

(1) The Customer-Generator shall furnish, install, operate and maintain, at its cost, the interconnection facilities (such as circuit breakers, relays, switches, synchronizing equipment, monitoring equipment, and control and protective devices and schemes) identified in Exhibit C (Customer-Generator-Owned Generating Facility and Interconnection Facilities).

(2) The point of interconnection is shown on the single-line diagram and three-line diagram (provided by the Customer-Generator and reviewed by the Company) which are attached to Exhibit C (Customer-Generator-Owned Generating Facility and Interconnection Facilities) (provided that the three-line diagram is not required if the Generating Facility's capacity is less than 30 kW). Pursuant to Company Rule 14H, Appendix I (Distributed Generating Facility Interconnection Standards Technical Requirements), Section 6.c (Review of Design Drawings), the Company must review and approve Customer-Generator's single-line and three-line diagrams prior to Customer-Generator constructing of the Generating Facility interconnection.

(3) The Customer-Generator agrees to test the Generating Facility, to maintain operating records, and to follow such operating procedures, as may be specified by the Company to protect the Company's system from damages resulting from the parallel operation of the Generating Facility, including such testing, records and operating procedures as more fully described in Exhibit C attached hereto.

(4) The Company may inspect the Generating Facility and Customer-Generator's interconnection facilities.

(b) **Company-Owned Interconnection Facilities.**

(1) The Company agrees to furnish, install, operate and maintain such interconnection facilities on its side of the point of interconnection with the Generating Facility as required for the parallel operation with the Generating Facility and more fully described in Exhibit D (Company-Owned Interconnection Facilities) attached

hereto and made apart hereof ("Company Interconnection Facilities"). All Company Interconnection Facilities shall be the property of the Company. Where portions of the Company Interconnection Facilities are located on the Customer-Generator's premises, the Customer-Generator shall provide, at no expense to the Company, a suitable location for and access to all such equipment. If a 120/240 Volt power source or sources are required, the Customer shall provide these at no expense to the Company.

(2) The Customer-Generator agrees to pay to the Company: (1) a non-refundable contribution for the Company's investment in the Company Interconnection Facilities described in Exhibit D (Company-Owned Interconnection Facilities), subject to the terms and conditions included in Exhibit D and to pay for other interconnection costs. The interconnection costs will not include the cost of an initial technical screening of the impact of the Generating Facility on the Company's system, but will include the actual cost (or such lesser amount as the Company may specify to facilitate the processing of interconnection requests for similarly situated facilities) of additional technical study for the Generating Facility.

11. **Purchase of Energy by the Company; Billing and Payment.** For Customer-Generator's full compensation under this Agreement, the Company agrees to purchase energy from the Customer-Generator pursuant to the terms and conditions set forth in Exhibit E (Company's Payment Obligations) attached hereto.

12. **Sale of Energy by the Company to the Customer-Generator**. Sales of energy delivered by the Company to the Customer-Generator shall be governed by the applicable rate schedule and the Company's rules filed with the Commission.

13. **Indemnification:**

(a) The Customer-Generator shall indemnify, defend and hold harmless the Company and its officers, directors, agents and employees, from and against all liabilities, damages, losses, fines, penalties, claims, demands, suits, costs and expenses (including reasonable attorney's fees and expenses) to or by third persons, including the Company's employees or subcontractors, for injury or death, or for injury to property, arising out of the actions or inactions of the Customer-Generator (or those of anyone under its control or on its behalf) with respect to its obligations under this Agreement, and/or arising out of the installation, operation and maintenance of the Generating Facility and/or the Customer-Generator Interconnection Facilities, except to the extent that such injury, death or damage is attributable to the gross negligence or intentional act or omission of the Company or its officers, directors, agents or employees.

(b) The Owner/Operator shall indemnify, defend and hold harmless the Company and its officers, directors, agents and employees, from and against all liabilities, damages, losses, fines, penalties, claims, demands, suits, costs and expenses (including reasonable attorney's fees and expenses) to or by third persons, including the Company's employees or subcontractors, for injury or death, or for injury to property, arising out of the actions or inactions of the Owner/Operator (or those of anyone under its control or on its behalf) with respect to its obligations under this Agreement, and/or arising out of the installation, operation and maintenance of the Generating Facility and/or the Interconnection Facilities, except to the extent that such injury, death or damage is attributable to the gross negligence or intentional act or omission of the Company or its officers, directors, agents or employees.

(c) The Company shall indemnify, defend and hold harmless the Customer-Generator, and its officers, directors, agents and employees, from and against all liabilities, damages, losses, fines, penalties, claims, demands, suits, costs and expenses (including reasonable attorney's fees and expenses) to or by third persons, including the Customer-Generator's employees or subcontractors, for injury or death, or for injury to property, arising out of the actions or inactions of the Company (or those of anyone under its control or on its behalf) with respect to its obligations under this Agreement, and/or arising out of the installation, operation and maintenance of the Company Interconnection Facilities, except to the extent that such injury, death or damage is attributable to the gross negligence or intentional act or omission of the Customer-Generator or its officers, directors, agents or employees.

Provided, however, where the Customer-Generator is an agency of the United States, the following Section shall be applicable in place of Paragraphs 14(a) and (b):

"The United States understands that it may be held liable for loss, damages expense and liability to third persons and injury to or death of persons or injury to property caused by the United States in its engineering design, construction ownership or operations of, or the making of replacements, additions betterment to, or by failure of, any of such party's works or facilities used in connection with this Agreement to the extent allowed by the Federal Tort Claims Act 28 U.S.C. § 2671 et seq. and the Agreement Disputes Act of 1978, 41 U.S.C. §§ 601-613.

Company shall be responsible for damages or injury caused by Company, Company's agents, officers, and employees in the course of their employment to the extent permitted by law."

Provided, however, where the Customer-Generator is an agency of the State of Hawaii (the "State"), the following Section shall be applicable in place of Paragraphs 14(a) and (b):

"The State shall be responsible for damages or injury caused by the State's agents, officers, and employees in the course of their employment to the extent that the State's liability for such damage or injury has been determined by a court or otherwise agreed to by the State. The State shall pay for such damage and injury to the extent permitted by law. The State shall use reasonable good faith efforts to pursue any approvals from the Legislature and the Governor that may be required to obtain the funding necessary to enable the State to perform its obligations or cover its liabilities hereunder. The State shall not request Company to indemnify the State for, or hold the State harmless from, any claims for such damages or injury.

Company shall be responsible for damages or injury caused by Company, Company's agents, officers, and employees in the course of their employment to the extent that

Company's liability for such damage or injury has been determined by a court or otherwise agreed to by Company, and Company shall pay for such damage and injury to the extent permitted by law. Company shall not request the State to indemnify Company for, or hold Company harmless from, any claims for such damages or injury."

(d) Nothing in this Agreement shall create any duty to, any standard of care with reference to, or any liability to any person not a party to it.

14. **Continuity of Service**.

(a) The Company may require the Customer-Generator to temporarily curtail, interrupt or reduce deliveries of energy when necessary in order for the Company to construct, install, maintain, repair, replace, remove, investigate, test or inspect any of its equipment or any part of the Company System including, but not limited to, accommodating the installation and/or testing of non-utility owned facilities to the Company system; or if the Company determines that such curtailment, interruption or reduction is necessary because of a system emergency, forced outage, operating conditions on its system; or the inability to accept deliveries of energy due to excess energy conditions; or if either the Generating Facility does not operate in compliance with good engineering and operating practices or acceptance of energy from the Customer-Generator by the Company would require the Company to operate the Company system outside of good engineering and operating practices which in this case shall include, but not be limited to, excessive system frequency fluctuations or excessive voltage deviations, and any situation that the Company system operator determines, at his or her sole discretion, could place in jeopardy system reliability.

(b) In the event that the Company temporarily curtails, interrupts, or reduces deliveries of energy pursuant to Section 19(a), the Company shall not be obligated to accept or pay for any energy from the Customer-Generator except for such energy that the Company notifies the Customer-Generator that it is able to take during this period. The Company shall take all reasonable steps to minimize the number and duration of interruptions, curtailments or reductions. Whenever feasible, Company shall give Customer-Generator reasonable notice of the possibility that interruption or reduction of deliveries may be required.

(c) The Company shall not be required to purchase energy during any period during which, due to operational circumstances, purchases from the Customer-Generator will result in costs greater than those which the Company would incur if it did not make those purchases, but instead generated an equivalent amount of energy itself. Without limiting the foregoing, conditions when curtailment of energy delivery by the Customer-Generator may be implemented by the Company may include when, during excess energy conditions, the Company would have to (i) cycle off-line any Base Load Unit, or (ii) remove one or more components of a combined cycle unit (such as shutting off one combustion turbine or one combustion turbine and the steam turbine of a dual-train combined cycle unit (consisting of two combustion turbines and one steam turbine)) in order to purchase energy from the Customer-Generator.

(d) In the event that the Company temporarily curtails or interrupts deliveries of energy from the Generating Facility pursuant to this Section 19, the Generating Facility shall not energize a de-energized utility line under any circumstances, but may operate the Generating Facility isolated from the utility system with an open tie point in accordance with Section 4.1 of Appendix I to Rule 14H.

15. **Personnel and System Safety**. If at any time the Company determines that the continued operation of the Generating Facility may endanger any person or property, the Company's electric system, or have an adverse effect on the safety or power quality of other customers, the Company shall have the right to disconnect the Generating Facility from the Company's electric system remotely or otherwise. The Generating Facility shall remain disconnected until such time as the Company is satisfied that the endangering or power quality condition(s) has been corrected, and the Company shall not be obligated to accept any energy from the Generating Facility during such period. The Company shall not be liable, directly or indirectly, for permitting or continuing to allow an attachment of the Generating Facility for the acts or omissions of the Customer-Generator that cause loss or injury, including death, to any third party.

16. **Prevention of Interference**. The Customer-Generator shall not operate equipment that superimposes a voltage or current upon the Company's system that interferes with the Company's operations, service to the Company's customers, or the Company's communication facilities. Such interference shall include, but not be limited to, overcurrent, voltage imbalance, and abnormal waveforms. If such interference occurs, the Customer-Generator must diligently pursue and take corrective action at its own expense after being given notice and reasonable time to do so by the Company. If the Customer-Generator does not take timely corrective action, or continues to operate the equipment causing interference without restriction or limit, the Company may, without liability, disconnect the Customer-Generator's equipment from the Company's system.

17. **Limitation of Liability**. Neither by inspection, if any, or non-rejection, nor in any other way, does the Company give any warranty, express or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed or maintained by the Customer-Generator or leased by the Customer-Generator from third parties, including without limitation the Generating Facility and any structures, equipment, wires, appliances or devices appurtenant thereto.

18. **Additional Information**. The Company reserves the right to require additional information, where necessary, to serve the Customer-Generator under this Agreement.

19. **No Material Changes to Generating Facility**. The Customer-Generator agrees that no material changes or additions to the Generating Facility shall be made without having obtained prior written consent from the Company, which consent shall not be unreasonably withheld. In no event may the Total Rated Capacity of the Generating Facility exceed 100 kW. If a Generating Facility changes ownership, the Company may require the new Customer-Generator and/or Owner/Operator to complete and execute an amended Agreement or new Agreement, as may be applicable.

20. **Notices**. Any notice required under this Agreement shall be in writing and mailed at any United States Post Office with postage prepaid and addressed to the Party, or personally delivered to the Party, at the address below. Changes in such designation may be made by notice similarly given. All written notices shall be directed as follows:

To Customer-Generator and Owner/Operator (if applicable): The Mailing Address listed in Exhibit B (Description of Generating Facility) attached hereto.

To Company:

Name: ________________________________
Address: ________________________________
Facsimile: ________________________________
Email: ________________________________

Notice sent by mail shall be deemed to have been given on the date of actual delivery or at the expiration of the fifth day after the date of mailing, whichever is earlier.

21. **Certification by Licensed Electrical Contractor**. Generating and interconnection systems must comply with all applicable safety and performance standards of the National Electrical Code (NEC), Institute of Electrical and Electronic Engineers (IEEE), and accredited testing laboratories such as the Underwriters Laboratories (UL), and where applicable, the rules of the Commission, or other applicable governmental laws and regulations, and the Company's interconnection requirements, in effect at the time of signing this agreement. This requirement shall include, but not be limited to, the interconnection provisions of the Company's Rule 14H, as authorized by the Commission. Licensed Electrical Contractor, as agent for Customer-Generator, certifies in Exhibit B (Description of Generating Facility) that once approved by the Company, the proposed Generating Facility will be installed to meet all preceding requirement(s).

22. **Force Majeure**. For purposes of this Agreement, "Force Majeure Event" means any event: (a) that is beyond the reasonable control of the affected party; and (b) that the affected party is unable to prevent or provide against by exercising reasonable diligence, including the following events or circumstances, but only to the extent they satisfy the preceding requirements: (a) acts of war, public disorder, insurrection or rebellion; floods, hurricanes, earthquakes, lighting, storms, and other natural calamities; explosions or fires; strikes, work stoppages, or labor disputes; embargoes ; and sabotage. If a Force Majeure Event prevents a party from fulfilling any obligations under this Agreement, such party will promptly notify the other party in writing, and will keep the other party informed on a continuing basis of the scope and duration of the Force Majeure Event. The affected party will specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the affected party is taking to mitigate the effects of the event on its performance. The affected part will be entitled to suspend or modify its performance of obligations under this Agreement, other than the obligation to make payments then due or becoming due under this Agreement, but only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of reasonable efforts. The affected party will use reasonable efforts to resume its performance as soon as possible.

23. **Good Engineering Practice**.

(a) Each party agrees to install, operate and maintain its respective equipment and facilities and to perform all obligations required to be performed by such party under this Agreement in accordance with good engineering practice in the electric industry and with applicable laws, rules, orders and tariffs.

(a) Wherever in this Agreement and the attached Exhibits the Company has the right to give specifications, determinations or approvals, such specifications, determinations and/or approvals shall be given in accordance with the Company's standard practices, policies and procedures, which may include the Company's Electric Service Installation Manual, the Company's Engineering Standard Practice Manual and the IEEE Guides and Standards for Protective Relaying Systems.

24. **Insurance**. The following insurance provisions are only applicable to Generating Facilities with a Total Rated Capacity greater than 10 kW but not exceeding 100 kW:

The Customer-Generator shall, at its own expense and during the term of the Agreement and any other time that the Generating Facility is interconnected with the Company's system, maintain in effect with a responsible insurance company authorized to do insurance business in Hawaii, the following insurance or its equivalent at Company's discretion that will protect the Customer-Generator and the Company with respect to the Generating Facility, the Generating Facility's operations, and the Generating Facility's interconnection with the Company's system:

A commercial general liability policy, covering bodily injury and property damage combined single limit of at least the following amounts based on the Total Rated Capacity of the generator (for solar systems—Total Rated Capacity of the generator or inverter, whichever is lower, can be used with appropriate technical documentation on inverter, if not higher Total Rated Capacity will be used), for any occurrence.

Commercial General Liability Coverage Amount	Total Rated Capacity of the Generating Facility
$1,000,000	Greater than 30 kW and less than or equal to 100 kW
$500,000	Greater than 10 kW and less than or equal to 30 kW

The Customer-Generator has responsibility to determine if higher limits are desired and purchased. Said insurance shall name the Company, its directors, officers, agents, and employees as additional insureds, shall include contractual liability coverage for written Agreements and agreements including this Agreement, and shall include provisions stating that the insurance will respond to claims or suits by additional insureds against the Customer-Generator or any other insured thereunder. Customer-Generator shall immediately provide written notice to the Company should the required insurance be cancelled, limited in scope, or not renewed upon expiration. "Claims made" policies are not acceptable, unless the Customer-Generator agrees to maintain coverage in full effect at all times during the term of this Agreement and for THREE (3) years thereafter. The adequacy of the coverage afforded by the required insurance shall be subject to review by the Company from time to time, and if it appears in such review that risk exposures require an increase in the coverages and/or limits of this insurance, the Customer-Generator shall make such increase to that extent and any increased costs shall be borne by the Customer-Generator. The insurance required hereunder shall provide that it is primary with respect to the Customer-Generator and the Company. The Customer-Generator shall provide evidence of such insurance, including insurer's acknowledgement that coverage applies with respect to this Agreement, by providing certificates of insurance to the Company within 30 days of any change. Initially, certificates of insurance must be provided to the Company prior to executing the Agreement and any parallel interconnection. The Customer-Generator's indemnity and other obligations shall not be limited by the foregoing insurance requirements. Any deductible shall be the responsibility of the Customer-Generator.

Alternatively, where the Customer-Generator is a governmental entity, Customer Generator may elect to be self-insured for the amounts set forth above in lieu of obtaining insurance coverage to those levels from an insurance company.

25. **Miscellaneous.**

(a) **Disconnection and Survival of Obligations.** Upon termination of this Agreement, the Generating Facility shall be disconnected from the Company's system. The termination of this Agreement shall not relieve the Parties of their respective liabilities and obligations, owed or continuing at the time of termination.

(b) **Governing Law and Regulatory Authority.** This Agreement was executed in the State of Hawaii and must in all respects be interpreted, governed, and construed under the laws of the State of Hawaii. This Agreement is subject to, and the parties' obligations hereunder include, operating in full compliance with all valid, applicable federal, state, and local laws or ordinances, and all applicable rules, regulations, orders of, and tariffs approved by, duly constituted regulatory authorities having jurisdiction.

(c) **Amendment, Modifications, or Waiver**. This Agreement may not be altered or modified by either of the Parties, except by an instrument in writing executed by each of them. None of the provisions of this Agreement shall be considered waived by a Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect. This Agreement contains the entire agreement and understanding between the Parties, their agents, and employees as to the subject matter of this Agreement. Each party also represents that in entering into this Agreement, it has not relied on any promise, inducement, representation, warranty, agreement or other statement not set forth in this Agreement.

(d) **Termination of Existing Agreement**. This Agreement shall supersede any existing agreement, if any, under which Customer-Generator is currently operating the Generating Facility and any such agreement shall be deemed terminated as of the date this Agreement becomes effective.

(e) **Assignment.** This Agreement may not be assigned by either Party without the prior written consent of the other party. Such consent shall not be unreasonably withheld.

(f) **Binding Effect.** This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors, legal representatives, and permitted assigns.

(g) **Relationship of Parties**. Nothing in this Agreement shall be deemed to constitute any Party hereto as partner, agent or representative of the other party or to create any fiduciary relationship between the Parties.

(h) **Limitations**. Nothing in this Agreement shall limit the Company's ability to exercise its rights or expand or diminish its liability with respect to the provision of electrical service pursuant to the Company's tariffs as filed with the Commission, or the Commission's Standards for Electric Utility Service in the State of Hawaii, which currently are included in the Commission's General Order Number 7, as either may be amended from time to time.

(i) **Multiple Counterparts**. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

IN WITNESS WHEREOF, the Parties hereto have caused two originals of this Agreement to be executed by their duly authorized representatives. This Agreement is effective as of the date first set forth above.

CUSTOMER-GENERATOR

By: ______________________________
Signature
Name: ______________________________
Print
Title: ______________________________

Date: ______________________________

OWNER/OPERATOR OF GENERATING FACILITY
(IF OTHER THAN CUSTOMER-GENERATOR)

By: ______________________________
Signature
Name: ______________________________
Print
Title: ______________________________

Date: ______________________________

HAWAIIAN ELECTRIC COMPANY, INC.

By: ______________________________
Signature
Name: ______________________________

Print

Title: ______________________________

Date: ______________________________

EXHIBIT A

NOTICE AND DISCLAIMER

POSSIBLE FUTURE RULES AND/OR RATE CHANGES AFFECTING YOUR GENERATING SYSTEM

- The Transitional Distributed Generation Tariff and Rule 14H (Company Rule 14, Paragraph H (Interconnection of Distributed Generating Facilities Operating in Parallel With The Company's Electric System), including but not limited to rules related to required system controls, electricity rates, charges and fees (collectively "Interconnection Rules") are subject to modification by the Hawaii Public Utilities Commission ("Commission").

- Your Agreement and Generating Facility (e.g. PV system) shall be subject to any future modifications of the Interconnection Rules by the Commission. Such modifications to the Interconnection Rules may positively or negatively impact any potential savings or the value of your Agreement and Generating Facility. You agree to pay for any costs related to such modification to the Interconnection Rules.

By signing below, you acknowledge that you have read, understand and agree to the above Notice and Disclaimer.

____

Customer-Generator (signature) Date

____

Owner/Operator (if applicable) (signature) Date

EXHIBIT B

DESCRIPTION OF GENERATING FACILITY

(To Be Filled Out By Customer-Generator)

1. **Customer-Generator Information**

Name (print): ______________________________

Mailing Address: ______________________________

City: ______________________ State: ______________ Zip Code: __________

Service Address: ______________________________
(If different from Mailing Address)

City: ______________________ State: ______________ Zip Code: __________

Phone: (____) ____________ Cell: (____) ____________ Email: ______________________

Electric Service Account or Meter #: ______________________________

2. **Owner/Operator (if different from Customer-Generator)**

Name: ______________________________

Mailing Address: ______________________________

City: ______________________ State: ______________ Zip Code: __________

Phone: (____) ____________ Cell: (____) ____________ Email: ______________________

3. **Generator Qualifications** (Check all that apply)

- ☐ Solar
- ☐ Wind Turbine
- ☐ Biomass
- ☐ Hydroelectric
- ☐ Hybrid (describe): ______________________________

Generating Facility Location and Tax Map Key: ______________________________

Maximum Site Load without Generation: ______________ kW

Minimum Site Load without Generation: ______________ kW

Maximum Generating Capability: ______________ kW

Maximum Export: ______________ kW

4. **Generator Technical Information**

Type of Generator:

- ☐ Synchronous

- ☐ Induction
- ☐ DC Generator or Photovoltaic with Inverter

<u>Photovoltaic System Information:</u>

Module Manufacturer	Model	Quantity	STC Rating (kW)

Total Module Capacity: ________________kW

Inverter Manufacturer	Model	Quantity	A/C Output Rating (kW)

Total Inverter Capacity: ________________ kW

Total System Capacity (lower of Total Module Capacity and Total Inverter Capacity): ________________ kW

<u>DC Generator (e.g. Wind) System Information:</u>

DC Generator Manufacturer: __________________________ Model Name: _________________ Model #: _____________
*** A copy of Generator Nameplate and Manufacturer's Specifications Sheet may be substituted.**

Total Capacity Rating: _________________ kW (For solar kW_{DC})

Fault Current Contribution of Generator: _________________ Amps

Inverter Manufacturer: _______________________________ Model Name: _________________ Model #: _____________
*** A copy of Generator Nameplate and Manufacturer's Specifications Sheet may be substituted.**

Total Capacity Rating: _________________ kW

<u>Energy Storage Device Information</u>:

Energy Storage Device Capacity (if applicable): __________________________ kW

5. **<u>Technical Information for Synchronous and Induction Generators</u> [Not applicable for DC Generators or Solar with Inverter]**

Number of starts per day: _______ Maximum Starting kVA: ____________ Generator Operating Power Factor: ________

<u>Generator Grounding Method:</u>

- ☐ Effectively Grounded
- ☐ Resonant Grounded
- ☐ **Low**-Inductance Grounded
- ☐ Low-Resistance Grounded
- ☐ High Resistance Grounded
- ☐ Ungrounded

<u>Generator Characteristic Data:</u>
* Not needed if Generator Nameplate and Manufacturer's Specification Sheet are provided.

Direct Axis Synchronous Reactance, $X_{d:}$ _______________ P.U.

Direct Axis Transient Reactance, $X'_{d:}$ _______________ P.U.

Direct Axis Subtransient Reactance, $X''_{d:}$ _______________ P.U.

Intertia Constant, H: _______________ P.U.

Excitation Response Ratio: _______________

Direct Axis Open-Circuit Transient Time Constant, $X_{d:}$ _______________ Seconds

Direct Axis Open-Circuit Subtransient Time Constant, T"do: _______________ Seconds

6. **<u>Interconnecting Equipment Technical Data</u>**

Will an interposing transformer be used between the generator and the point of interconnection?
☐ Yes
☐ No

<u>Transformer Data (if applicable)</u>:
* A copy of transformer Nameplate and Manufacturer's Test Report may be substituted.

Size: ______________ KVA

Transformer Primary: _______________ Volts
☐ Delta
☐ Wye
☐ Wye Grounded

Transformer Secondary: _____________ Volts
☐ Delta
☐ Wye
☐ Wye Grounded

Transformer Impedance: ____________________ % on _________ KVA Base

<u>Transformer Fuse Data (if applicable)</u>:
* Attach copy of fuse manufacturer's Minimum Melt & Total Clearing Time-Current Curves.
☐ At Primary Voltage; or
☐ At Secondary Voltage

Manufacturer: _____________________ Type: ________________ Size: _________________ Speed: ________________

<u>Transformer Protection (if not fuse)</u>:

Please describe: ____

<u>Generator Circuit Breaker (if applicable):</u>
* A copy of circuit breaker's Nameplate and Specification Sheet may be substituted.

Manufacturer: ____ Type: _______________________________________

Continuous Load Rating: ________________ Amps

Interrupting Rating: ____________________ Amps

Trip Speed: ____________________ Cycles

Circuit Breaker Protective Relays (if applicable):
* Enclose copy of any proposed Time-Overcurrent Coordination Curves.

Manufacturer	Type	Style/Catalog No.	Proposed Setting

Current Transformer Data (if applicable):
* Enclose copy of Manufacturer's Excitation & Ratio Correction Curves)

Manufacturer	Type	Accuracy Class	Proposed Ratio Connection
			/5
			/5
			/5
			/5

Generator Disconnect Switch:

A generator disconnect device (isolation device) must be installed with features as described in the "Distributed Generating Facility Interconnection Standards, Technical Requirements" as set forth in Rule 14 (Paragraph H.1) of the Company's tariff, and which is readily and safely accessible to Company.

Manufacturer: ________________________________ Type: ________________________ Catalog No.:__________________

Rated Volts: __________________________ Rated Amps: __________________________

Phase:

- ☐ Single Phase
- ☐ Three Phase

Mounting Location: ____

7. **General Technical Information**

Enclose copy of the following documents:

- ☐ **Single Line Diagram**: Showing configuration and interconnection of all equipment, current and potential circuits and protection and control schemes.
- ☐ **Relay list and trip scheme**: Showing all protection, synchronizing and auxiliary relays that are required to operate the Generating Facility in a safe and reliable manner.
- ☐ **Three-line diagram** (if the Generating Facility's capacity is greater than or equal to 30 kW): Showing potential transformer and current transformer ratios, and details of the Generating Facility's configuration, including relays, meters, and test switches.

8. **Installation Details**

Installing Electrical Contractor: ________________________________

License Holder: ____

Hawaii License #: ____

Mailing Address: ____

City: ______________________ State:__________________ Zip Code: ____________________

Phone: (____)______________ Cell: (____)______________ Email: ______________________

Interconnection Date*: ________________________ (to be filled out by the Company upon the Company's approval and execution of the Agreement).

Supply certification that the generating system will be installed and inspected in compliance with the local Building/Electrical code of the County of ____________________________________.

* Under no circumstances shall a Customer-Generator interconnect and operate a generating facility in parallel with the Company's electric system without prior written approval by the Company in the form of a fully executed Agreement. Generating facilities that incorporate the use of an energy storage device, e.g. battery storage, regardless of whether such energy storage device is intended to operate in parallel with the Company's transmission and/or distribution facilities, shall obtain an interconnection review by the Company pursuant to this Agreement. Energy storage systems that are intended to be installed by an Eligible Customer-Generator after Company's execution of an Agreement shall constitute a material change and addition to a generating facility and shall require interconnection review pursuant to this Rule prior to installation.

Generating System Building Permit # (Certificate of Completion or Notice of Electrical Inspection?): (to be filled out by the Company upon the Company's approval and execution of Agreement): ______________________________.

9. **Generator/Equipment Certification**

Generating systems that utilize inverter technology must be compliant with *Institute of Electrical and Electronics Engineers IEEE Std 1547* and *Underwriters Laboratories UL 1703* and *UL 1741* in effect at the time this Agreement is executed. Generating systems that use a rotating machine must be compliant with applicable National Electrical Code, Underwriters Laboratories, and Institute of Electrical and Electronics Engineers standards and rules and orders of the Public Utilities Commission of the State of Hawaii in effect at the time this Agreement is executed. **By signing below, the Applicant certifies that the installed generating equipment will meet the appropriate preceding requirement(s) and can supply documentation that confirms compliance.**

Customer-Generator: ____
Signature Date

Electrical Contractor: ____
Signature Date

10. **Insurance (if applicable)**

Insurance Carrier: ____

EXHIBIT C

CUSTOMER-GENERATOR-OWNED GENERATING FACILITY AND INTERCONNECTION FACILITIES

[To be filled out by Customer-Generator if Generating Facility greater than 10 kW]

1. **Generating Facility**

a. Compliance with laws and standards. The Generating Facility, Generating Facility design, and Generating Facility drawings shall meet all applicable national, state, and local laws, rules, regulations, orders, construction and safety codes, and shall satisfy the Company's Distributed Generating Facility Interconnection Standards, Technical Requirements ("Interconnection Standards"), as set forth in Rule 14, Paragraph H.1 of the Company's tariff.

b. Avoidance of adverse system conditions. The Generating Facility shall be designed, installed, operated and maintained so as to prevent or protect against adverse conditions on the Company's system that can cause electric service degradation, equipment damage, or harm to persons, such as:

- Unintended islanding.
- Inadvertent and unwanted re-energization of a Company dead line or bus.
- Interconnection while out of synchronization.
- Overcurrent.
- Voltage imbalance.
- Ground faults.
- Generated alternating current frequency outside of permitted safe limits.
- Voltage outside permitted limits.
- Poor power factor or reactive power outside permitted limits.
- Abnormal waveforms.

c. Specification of protection, synchronizing and control requirements. The Customer-Generator shall provide the design drawings, operating manuals, manufacturer's brochures/instruction manual and technical specifications, manufacturer's test reports, bill of material, protection and synchronizing relays and settings, and protection, synchronizing, and control schemes for the Generating Facility to the Company for its review, and the Company shall have the right to specify the protection and synchronizing relays and settings, and protection, synchronizing and control schemes that affect the reliability and safety of operation and power quality of the Company's system with which the Generating Facility is interconnected ("Facility Protection Devices/Schemes").

d. **Generating Facility protection**. The Customer-Generator is solely responsible for providing adequate protection for the Generating Facility.

e. **Customer-Generator Interconnection Facilities**.

(i) The Customer-Generator shall furnish, install, operate and maintain interconnection facilities (such as circuit breakers, relays, switches, synchronizing equipment, monitoring equipment, and control and protective devices and schemes) designated by or acceptable to the Company as suitable for parallel operation of the Generating Facility with the Company's system ("Customer-Generator Interconnection Facilities"). Such facilities shall be accessible at all times to authorized Company personnel.

(ii) The Customer-Generator shall comply with the Company's Interconnection Standards. If a conflict exists between the Interconnection Standards and this Agreement, this Agreement shall control.

(iii) 1) Single-line diagram of the Generating Facility, 2) relay list, trip scheme and settings of the Generating Facility, 3) Generating Facility Equipment List, and 4) three-line diagram (if the Generating Facility's capacity is greater than or equal to 30 kW), which identify the circuit breakers, relays, switches, synchronizing equipment, monitoring equipment, and control and protective devices and schemes, shall, after having obtained prior written consent from the Company, be attached to Exhibit B and made a part hereof at the time the Agreement is signed. The single-line diagram shall include pertinent information regarding operation, protection, synchronizing, control, monitoring and alarm requirements. The single-line diagram and three-line diagram shall expressly identify the point of interconnection of the Generating Facility to the Company's system. The relay list, trip scheme and settings shall include all protection, synchronizing and auxiliary relays that are required to operate the Generating Facility in a safe and reliable manner. The three-line diagram shall show potential transformer and current transformer ratios, and details of the Generating Facility's configuration, including relays, meters, and test switches.

f. **Approval of Design Drawings**. If the Generating Facility's capacity is greater than or equal to 30 kW, the single-line diagram, relay list, trip scheme and settings of the Generating Facility, and three-line diagram shall be approved by a Professional Electrical Engineer registered in the State of Hawaii prior to being submitted to the Company. Such approval shall be indicated by the engineer's professional seal on all drawings and documents.

2. Verification Testing.

a. Upon initial parallel operation of the Generating Facility, or any time interface hardware or software is changed, a verification test shall be performed. A licensed professional engineer or otherwise qualified individual shall perform verification testing in accordance with the manufacturer's published test procedure. Qualified individuals include professional engineers, factory trained and certified technicians, and licensed electricians with experience in testing protective equipment. The Company reserves the right to witness verification testing or require written certification that the testing was performed.

b. Verification testing shall also be performed every four years. The Company reserves the right to perform, at its expense, additional verification testing. All verification tests prescribed by the manufacturer shall be performed. If wires must be removed to perform certain tests, each wire and each terminal shall be clearly and permanently marked. The Customer-Generator shall maintain verification test reports for inspection by the Company.

c. Inverters shall be verified once per year as follows: once per year the Customer-Generator shall operate the customer generator system disconnect switch and verify the Generating Facility automatically shuts down and does not reconnect with the Company's system until the Company's system continuous normal voltage and frequency have been maintained for a minimum of 5 minutes. The Customer-Generator shall maintain a log of these operations for inspection by the Company.

d. Any system that depends upon a battery for trip power shall be checked once per month for proper voltage. Once every four (4) years the battery shall either be replaced or have a discharge test performed. The Customer-Generator shall maintain a log of these operations for inspection by the Company.

e. Tests and battery replacements as specified in this section 2 of Exhibit B shall be at the Customer-Generator's expense.

3. Inspection of the Generating Facility.

a. The Company may, in its discretion and upon reasonable notice not to be less than 24 hours (unless otherwise agreed to by the Company and the Customer-Generator), observe the construction of the Generating Facility (including but not limited to relay settings and trip schemes) and the equipment to be installed therein.

b. Within fourteen days after receiving a written request from the Customer-Generator to begin producing electric energy in parallel with the Company's system, the Company may inspect the Generating Facility (including but not limited to relay settings and trip schemes) and observe the performance of the verification testing. The Company may accept or reject the request to begin producing electric energy based upon the inspection or verification test results.

c. If the Company does not perform an inspection of the Generating Facility (including but not limited to relay settings and trip schemes) and observe the performance of verification testing within the fourteen-day period, the Customer-Generator may begin to produce energy after certifying to the Company that the Generating Facility has been tested in accordance with the verification testing requirements and has successfully completed such tests. After receiving the certification, the Company may conduct an inspection of the Generating Facility (including but not limited to relay settings and trip schemes) and make reasonable inquiries of the Customer-Generator, but only for purposes of determining whether the verification tests were properly performed. The Customer-Generator shall not be required to perform the verification tests a second time, unless irregularities appear in the verification test report or there are other objective indications that the tests were not properly performed in the first instance.

d. The Company may, in its discretion and upon reasonable notice not to be less than 24 hours (unless an apparent safety or emergency situation exists which requires immediate inspection to resolve a known or suspected problem), inspect the Generating Facility (including but not limited to relay settings and trip schemes) and its operations (including but not limited to the operation of control, synchronizing, and protection schemes) after the Generating Facility commences operations.

4. Operating Records and Procedures.

a. The Company may require periodic reviews of the maintenance records, and available operating procedures and policies of the Generating Facility.

b. The Customer-Generator must separate the Generating Facility from the Company's system whenever requested to do so by the Company's System Operator pursuant to this Agreement. It is understood and agreed that at times it may not be possible for the Company to accept electric energy due to temporary operating conditions on the Company's system, and these periods shall be specified by the Company's System Operator. Notice shall be given in advance when these are scheduled operating conditions.

c. Logs shall be kept by the Customer-Generator for information on unit availability including reasons for planned and forced outages; circuit breaker trip operations, relay operations, including target initiation and other unusual events. The Company shall have the right to review these logs, especially in analyzing system disturbance.

5. Changes to the Generating Facility, Operating Records, and Operating Procedures.

a. The Customer-Generator agrees that no material changes or additions to the Generating Facility as reflected in the single-line diagram, relay list, trip scheme and settings of the Generating Facility, Generating Facility Equipment List, and three-line diagram (if the Generating Facility's capacity is greater than or equal to 30 kW), shall be made without having obtained prior written consent from the Company, which consent shall not be unreasonably withheld.

b. As a result of the observations and inspections of the Generating Facility (including but not limited to relay list, trip scheme and settings) and the performance of the verification tests, if any changes in or additions to the Generating Facility, operating records, and operating procedures and policies are required by the Company, the Company shall specify such changes or additions to the Customer-Generator in writing, and the Customer-Generator shall, as soon as practicable, but in no event later than thirty (30) days after receipt of such changes or additions, respond in writing, either noting agreement and action to be taken or reasons for disagreement. If the Customer-Generator disagrees with the Company, it shall note alternatives it will take to accomplish the same intent, or provide the Company with a reasonable explanation as to why no action is required by good engineering practice.

(Additional terms and provisions to be added as necessary. Note: This parenthetical phrase should be deleted when the agreement is finalized.)

6. <u>Generating Facility Equipment List</u>.

The Generating Facility shall include the following equipment:

(Specific items to be added as necessary. Note: This parenthetical phrase should be deleted when the agreement is finalized.)

(This Generating Facility Equipment List, together with the single-line diagram, relay list and trip scheme, and three-line diagram (if the Generating Facility's capacity is greater than or equal to 30 kW), should be attached behind Exhibit B. Note: This parenthetical phrase should be deleted when the agreement is finalized.)

EXHIBIT D

COMPANY-OWNED INTERCONNECTION FACILITIES

[To be filled out by Company if Generating Facility is greater than 10 kW]

1. Description of Company Interconnection Facilities

The Company will purchase, construct, own, operate and maintain all interconnection facilities required to interconnect the Company's system with the Generating Facility at ___ volts, up to the point of interconnection.

The Company Interconnection Facilities, for which the Customer-Generator agrees to pay, include:

[Need to specify the interconnection facilities. If no interconnection facilities, state "None".]

2. Customer-Generator Payment to Company for Company Interconnection Facilities, Review of Generating Facility, and Review of Verification Testing

The Customer-Generator shall pay to the Company the total estimated interconnection cost to be incurred by the Company (Total Estimated Interconnection Cost), which is comprised of (i) the estimated cost of the Company Interconnection Facilities, (ii) the estimated engineering costs associated with a) developing the Company Interconnection Facilities and b) reviewing and specifying those portions of the Generating Facility which allow interconnected operation, and iii) witnessing and reviewing the verification testing. The following summarizes the Total Estimated Interconnection Cost:

Description	Estimated Cost ($)
[Need to specify the estimated interconnection cost. If no cost, state "None".]	
Total Estimated Interconnection Cost	**$**

The Total Estimated Interconnection Cost, which, except as otherwise provided herein, is non-refundable, shall be paid by the Customer-Generator fourteen (14) days after receipt of an invoice from the Company, which shall be provided not less than thirty (30) days prior to start of procurement of the Company Interconnection Facilities.

Within thirty (30) days of receipt of an invoice, which shall be provided within fourteen (14) days of the final accounting, which shall take place within sixty (60) days of completion of construction of the Company Interconnection Facilities, the Customer-Generator shall remit to the Company the difference between the Total Estimated Interconnection Cost paid to date and the total actual interconnection cost (Total Actual Interconnection Cost). The latter is comprised of (i) the total costs of the Company Interconnection Facilities, and (ii) the total engineering costs associated with a) developing the Company Interconnection Facilities and b) reviewing and specifying those portions of the Generating Facility which allow interconnected operations as such are described in Exhibit B, and iii) reviewing the verification testing. If in fact the Total Actual Interconnection Cost is less than the payments received by the Company as the Total Estimated Interconnection Cost, the Company shall repay the difference to the Customer-Generator within thirty (30) days of the final accounting.

If the Agreement is terminated prior to the Customer-Generator's payment for the Total Actual Interconnection Cost (or the portion of this cost which has been incurred) or prior to the Company's repayment of the overcollected amount of the Total Estimated Interconnection Cost (or the portion of this cost which has been paid), such payments shall be made by the Customer-Generator or Company, as appropriate. If payment is due to the Company, the Customer-Generator shall pay within thirty (30) days of receipt of an invoice, which shall be provided within fourteen (14) days of the final accounting, which shall take place within sixty (60) days of the date the Agreement is terminated. If payment is due to the Customer-Generator, the Company shall pay within thirty (30) days of the final accounting.

All Company Interconnection Facilities shall be the property of the Company.

3. Operation, Maintenance and Testing Costs

The Company will bill the Customer-Generator monthly and the Customer-Generator will, within 30 days after the billing date, reimburse the Company for any costs incurred in operating, maintaining or testing the Company Interconnection Facilities. The Company's costs will be determined on the basis of outside service costs, direct labor costs, material costs, transportation costs, applicable overheads at time incurred and applicable taxes. Applicable overheads will include such costs as vacation, payroll taxes, non-productive wages, supervision, tools expense, employee benefits, engineering administration, corporate administration, and materials handling. Applicable taxes will include the Public Service Company Tax, and Public Utility Fee.

EXHIBIT E

COMPANY'S PAYMENT OBLIGATIONS

<u>Billing and Payment</u>

A. General:

(1) The metering and billing arrangement covered by the Transitional Distributed Generation Tariff Standard Power Purchase and Interconnection Agreement (100 kW or less) ("Agreement") shall be governed by the following mutually agreed upon terms and conditions:

(2) Customer-Generators under this Agreement shall be billed monthly for the billing period for the energy supplied by the Company, in accordance with the Company's Rule No. 8, the applicable rate schedule, and the Company's rules filed with the Commission.

(3) The measurement of kilowatthours supplied by the Company to the Customer-Generator and the kilowatthours delivered by the Customer-Generator to the Company for the first bill of the initial 12-month reconciliation period shall begin on the start date of the first billing period after the installation of the required meter(s).

(4) Every 12 months, a reconciliation of the Customer-Generator's energy consumption supplied by the Company with the energy credits delivered by the Generating Facility for that 12-month period will be performed as described in Section D of this <u>Exhibit E</u> (Company's Payment Obligations).

B. Monthly Minimum Charge

Each month, the Customer-Generator will be charged the Minimum Charge provided in the applicable rate schedule in effect during the billing period.

C. Energy Credits

(1) The Company shall pay for each kilowatt-hour of electricity delivered to the Company by Customer-Generator ("Energy Credit") as follows:

<u>Energy Credit Calculation in ¢ / kWhr</u>

Base Fuel Energy Charge (from Schedule R) + Energy Cost Adjustment Factor

(2) The rates paid by the Company for the electric energy purchased under this Agreement, i.e. Energy Credit, may be adjusted periodically as ordered and approved by the Commission or as permitted under existing tariffs.

(3) Payment will be made in the form of a bill credit on the customer's electric bill, subject to the terms described in Section D of this Exhibit E below.

D. Energy Credits and Consumption Costs

(1) In each billing period, the Energy Credits delivered by the Generating Facility during such billing period shall be credited against the cost of the Customer-Generator's kWh consumption, i.e. energy delivered by the Company to the Customer-Generator for such billing period under the applicable rate schedule ("Consumption Costs"). Energy Credits shall not be credited against the Minimum Charge or any other applicable fixed charges for the billing period.

(2) When Energy Credits delivered by the Generating Facility during a billing period exceed the Consumption Costs for the same period, the unused Energy Credits shall be carried over to subsequent billing period(s) within the current 12-month reconciliation period as a monetary credit ("Unused Energy Credits").

(3) When Consumption Costs during a billing period exceed the Energy Credits delivered by the Generating Facility for the same period, and also exceed any Unused Energy Credits carried over from the prior months since the last 12-month reconciliation period, the Customer-Generator shall pay for the excess Consumption Costs.

E. Annual Reconciliation of Energy Credits

(1) The Energy Credits delivered by the Customer-Generator, Consumption Costs incurred by the Customer-Generator and Unused Energy Credits, if any, shall be recorded in each billing period of the 12-month reconciliation period. At the end of each 12-month reconciliation period, a final reconciliation will be made for any remaining Unused Energy Credits. Unused Energy Credits will be applied to the excess of the total of the electric bill for the 12-month reconciliation period above the minimum charge plus any other applicable fixed charges. Any Unused Energy Credits applied in this reconciliation shall be credited on the customer bill. Any Unused Energy Credits that remain unused at the end of each 12-month reconciliation period shall expire and not be carried over to the next 12-month reconciliation period.

(2) If a Customer-Generator terminates its Agreement service prior to the end of any 12-month reconciliation period, the Company shall reconcile the Customer-Generator's account in the same manner as the reconciliation that would have been performed at the end of the normal 12-month reconciliation period.

(3) The kilowatthours supplied by the Company and, if any, the kilowatthours delivered by the Customer-Generator, including an accounting of the Energy Credits since the last 12-month reconciliation period, the Energy Credits applied in each billing period of the current 12-month reconciliation period and the remaining t Unused Energy Credits, if any, will be included in the Customer-Generator's regular billing statement.

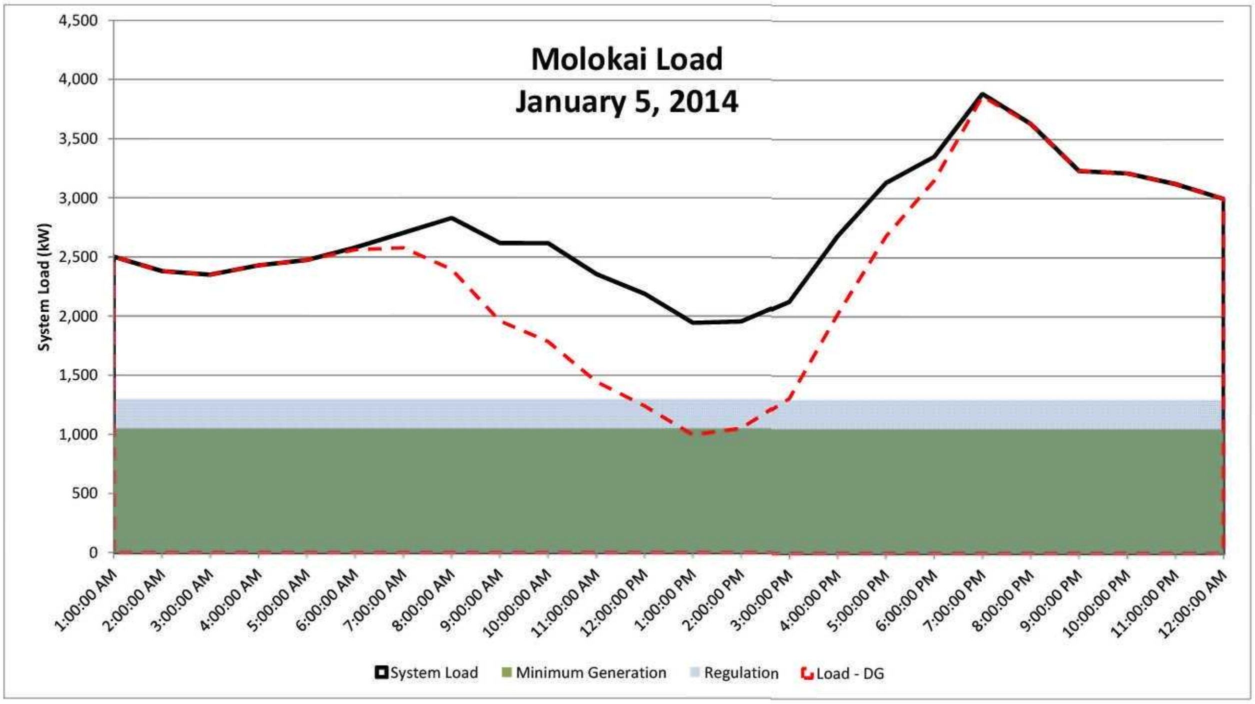
	Nameplate Rating, MW				
	Oahu	Maui	Lanai	Molokai	Hawaii
NEM that is already interconnected or that have been approved for interconnection but not yet interconnected as of **12/31/14**	254.4	61.6	0.7	2.5	55.0
NEM that are in the queue awaiting review or interconnection approval as of **12/31/14**	32.6	10.4	0.0	0.3	5.4
Additional NEM applications that are not yet in the queue that may be received through **03/20/15**	10.8	4.7	0.1	0.0	3.2
Total NEM	297.8	76.7	0.8	2.8	63.6
Highest Recorded Peak Demand Recorded in 2014 as of 12/31/2014, MW-net (except Lanai and Molokai, which are MW-gross)	1,165	190.7	5.1	5.5	187.8
Total NEM as a Percentage of Highest Recorded Peak Demand in 2014	25.6%	40.2%	15.8%	51.0%	33.8%
# of new forecasted systems through 3/20/15 (5 kW in size)	2,160	940	20	0	642

Moloka‘i Conditions

It should be noted that the circuit penetration level is not the sole factor that is used to determine whether a DG system can be interconnected to the distribution system. Other issues at the circuit level may need to be mitigated, and various system level impacts from DG have been identified which will need to be mitigated to preserve system reliability and operability. While all systems will eventually see these impacts, Lana‘i and Moloka‘i are the first systems to achieve levels of impact which require certain mitigation measures, because of the high proportion of total DG to system size. Moloka‘i in particular has reached a point where additional DG must be subject to output control by the Maui Electric operator in order to keep the system reliable and operable. Maui Electric must be able to match generation to the demand at all times in order to provide reliable power and maintain the system frequency. With only the minimum generation that Maui Electric can run and still maintain reliability, the capacity of DG that has been currently installed and approved to be installed (approximately 2.5 MW) will exceed the ability of the system to use the DG energy during the minimum day time load of the system (approximately 2 MW). At this time, Moloka‘i is near or at the point where generation cannot be matched to demand, and frequency cannot be maintained reliably.

The Moloka‘i situation can be best shown by the following illustration. The actual system load for January 5, 2014 is shown with a dark black line, the minimum generation Maui Electric can operate reliably with is shown in green, and the minimum amount of regulation down carried by the generators is shown in blue. (Regulation down is generation above the minimum to allow the generators to lower output in response to a reduction in load. Moloka‘i has several large water pumps, for example, that range from 200 to 300 kW in size and when one of them turns off, generators need to lower output by that much to maintain frequency. Additionally, this regulation is held to ensure compliance with environmental regulations.) For the purposes of this illustration, all DG that was installed by January 5th 2014 is assumed to be accounted for in the load data for the day (the dark black line). Since January 5th, however, Maui Electric has accepted over 1,200 kW of additional DG, the majority of which has not yet been interconnected. To account for this capacity, the red dashed line estimates what the load curve for Molokai will look like after this additional DG is interconnected by subtracting it from the actual load data. It should be noted that to account for diversity across the island and other less than ideal conditions such as varied PV orientation, ***only 75% of the approved capacity was subtracted from the load data.*** As can be seen from the illustration, the projected load accounting for the approved DG capacity (red dashed line) will exhaust Maui Electric's ability to respond to reductions in load (when the red crosses the blue portion representing regulation capacity). Further, if the load dips below the minimum generation Maui Electric can operate reliably with, or as depicted in this illustration, when the red dashed line crosses the green portion of the graph, potentially frequency control will have been lost and overfrequency will ensue, some DG will trip offline due to that over frequency, and Maui Electric cannot continue to operate the generation within the limits required for environmental requirements and would have to shut down that generation to avoid regulatory action. This would result in cascading outages and potential system failure.

Therefore, Maui Electric will not be able to interconnect any more DG systems whose output cannot be controlled by the utility on the island of Moloka'i until such time that daytime demand increases by a sufficient extent and/or when there are other means to use the available excess energy in a cost effective manner.


Molokai Load
January 5, 2014
System Load (kW)
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1:00:00 AM
2:00:00 AM
3:00:00 AM
4:00:00 AM
5:00:00 AM
6:00:00 AM
7:00:00 AM
8:00:00 AM
9:00:00 AM
10:00:00 AM
11:00:00 AM
12:00:00 PM
1:00:00 PM
2:00:00 PM
3:00:00 PM
4:00:00 PM
5:00:00 PM
6:00:00 PM
7:00:00 PM
8:00:00 PM
9:00:00 PM
10:00:00 PM
11:00:00 PM
12:00:00 AM
System Load
Minimum Generation
Regulation
Load - DG

CERTIFICATE OF SERVICE

I hereby certify that I have this date served a copy of the foregoing HAWAIIAN ELECTRIC COMPANIES' MOTION FOR APPROVAL OF NEM PROGRAM MODIFICATION AND ESTABLISHMENT OF TRANSITIONAL DISTRIBUTED GENERATION PROGRAM TARIFF, together with this CERTIFICATE OF SERVICE, as indicated below by hand delivery, by mailing a copy by United States mail, postage prepaid, and/or electronically transmitted, to the following:

JEFFREY T. ONO EXECUTIVE DIRECTOR DEPT. OF COMMERCE & CONSUMER AFFAIRS DIVISION OF CONSUMER ADVOCACY P.O. Box 541 Honolulu, Hawai'i 96809	2 Copies Via Hand Delivery
DAVID BISSELL PRESIDENT AND CEO KAUAI ISLAND UTILITY COOPERATIVE 4463 Pahe'e Street, Suite 1 Lihue, Hawai'i 96766-2000	1 Copy U.S. Mail
KENT D. MORIHARA KRIS N. NAKAGAWA LAUREN M., IMADA Morihara Lau & Fond LLP 841 Bishop Street, Suite 400 Honolulu, Hawai'i 96813 Counsel for KAUAI ISLAND UTILITY COOPERATIVE	1 Copy U.S. Mail

DATED: Honolulu, Hawai'i January 20, 2015

HAWAIIAN ELECTRIC COMPANY, INC.

Marisa K. Chun

Marisa K. Chun