# *STAFF PROPOSAL FOR UPDATED PERFORMANCE-BASED REGULATIONS*

*Proceeding to Investigate Performance-Based Regulation (2018-0088)*

*Hawaii Public Utilities Commission | February 7, 2019*

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# 1 INTRODUCTION: THE NEED FOR REGULATORY REFORM

Hawaii's electricity system is undergoing an historic transition away from centralized, fossil fuel-based generation towards an increasingly renewable, distributed system. The State of Hawaii has supported this transition through a 100% Renewable Portfolio Standard (RPS) by 2045[1] as well as other policy and regulatory initiatives. At the same time, Hawaii experiences several exceptional conditions, including the isolated nature of its individual island electrical systems, the continued reliance on imported fossil fuel, as well as the highest electricity prices in the nation. This context requires that Hawaii's regulatory framework evolve and adapt to the changing system.

Fortunately, there are ample opportunities to achieve the state's clean energy goals and increase customer choice while simultaneously reducing the total cost of energy services. In fact, as highlighted in the sections that follow, these actions are inherently linked. And yet, the utility's financial incentives are not currently aligned with the pursuit of these goals. By updating regulation of the electric industry for the modern age, the pace of positive change can accelerate to yield significant benefits for customers, the HECO Companies,[2] the environment, and Hawaii's economy alike.[3]

To support Hawaii's clean energy goals and ensure this transition benefits all customers, Hawaii Public Utilities Commission ("Commission") staff have proposed updated performance-based regulations. This Staff Proposal outlines common sense changes to utility regulations intended to help the HECO Companies operate more like a business in the competitive marketplace, with performance incentives that steer the utility toward achieving the state's goals at the least cost to customers.

The proposed changes would provide immediate benefits to customers. Performance-based regulations should deliver significant "day one" savings on customer bills as soon as the new regulations take effect. Updated regulations should also encourage improvements in customer service and better options to help manage energy use.

[1]The State of Hawaii has also stated an executive policy to attain 100% renewable generation by 2045.

[2]The Hawaiian Electric Companies ("HECO Companies" or "Companies") refers to Hawaiian Electric Company, Inc. ("HECO"), Maui Electric Company, Ltd. ("MECO"), and Hawaii Electric Light Company, Inc. ("HELCO").

[3]*See* Toby Shea, "Performance Based Ratemaking Rating Agency Perspective," Moody's Investors Service, September 27, 2018, Hawaii PBR Workshop #2, at 2, 5-6 (noting "PBR correlates with higher credit quality"); Michael Weinstein, "Power, Utilities, and Alternative Energy: Utility Equity Valuation and the Impact of Performance-Based Ratemaking," Credit Suisse Equity Research, September 27, 2018, Hawaii PBR Workshop #2, at 1, 10 (noting [i]nvestors don't *require* a guaranteed competitive return, just a fair, transparent, and achievable opportunity to *earn* it" and that "[l]owering fuel costs also provides room in customer bills for clean investment"). Docket No. 2018-0088, "Presentations from Technical Workshop #2," filed October 12, 2018.

Ultimately, performance-based regulations will ensure Hawaii continues to set the pace and remains a leader in the clean energy transition. In the longer term, the new regulations will accelerate Hawaii's transition to renewable energy, reducing the state's dependence on imported oil and increasing investment in clean energy made here in Hawaii. Updated regulations will also improve resilience of the state's communities to withstand severe weather or unexpected events while creating value for Hawaii's residents and businesses.

## 1.1 THE IMPERATIVE: HIGHEST RATES IN THE NATION

Hawaii experiences the highest electricity rates ($/kWh) in the country. In 2017, the average residential price for electricity in Hawaii was 29.5 cents per kWh, over twice the national average of 12.9 cents per kWh.[4] Consequently, the Commission has stressed the need for the HECO Companies to control costs and reduce electric bills.[5] Although progress has been made, it is apparent that aspects of the current regulatory framework may not adequately incent an aggressive pursuit of cost reductions.

Staff suggests the HECO Companies have an opportunity to realize material customer savings primarily through the following actions: (1) expeditious replacement of fossil fuel generation with cost-effective renewables; (2) careful management of capital expenditures; and (3) achievable reductions to O&M expenses.

Staff's recommended changes to the regulatory framework, as outlined in Section 4, are intended to reward the HECO Companies for capturing these cost-reduction opportunities, while simultaneously ensuring verifiable and substantial customer savings.

## 1.2 THE OPPORTUNITY

### 1.2.1 Shifting from Fossil Fuel to Cost-Effective Renewable Energy

Recent technological advancements and falling costs have given rise to an environment where new renewables and energy storage systems cost less (on a levelized basis) than existing fossil fuel-based generation. While fossil fuel prices have fluctuated, energy prices[6] for renewable

[4] *See* Energy Information Agency, 2017 Total Electric Industry – Average Retail Price (cents/kWh), *available at* https://www.eia.gov/electricity/sales_revenue_price/pdf/table4.pdf; *see also* Hawaii Energy Facts & Figures, June 2018, Department of Business, Economic, Development & Tourism, Hawaii State Energy Office at 2. From 2007 to 2017, Hawaii's electric rates have been consistently more than twice the national average. For some periods, Hawaii's electric rates were three times that of the national average electric rate.

[5] *See, e.g.*, *In re Application of Hawaiian Electric Company, Inc. for Approval of General Rate Case and Revised Rate Schedules/Rules*, Docket No. 2016-0328, Interim Decision and Order No. 35100, filed December 15, 2017, at 47, 49.

[6] Energy prices for approved projects are based on average energy costs for Fiscal Year (FY) 2018 or approved PPA energy prices, depending if the approved project was commercially online in FY 2018.

power purchase agreements ("PPAs") and distributed energy resources ("DER") have significantly declined over the past several years. Recent prices for renewable energy projects, both utility-scale and distributed, are below the cost of most fossil fuel-based resources.

Figure 1 illustrates the volatility of HECO's avoided cost, which is primarily driven by changing oil prices. Also shown, is the steady and substantial decline in energy prices for renewable energy PPAs on Oahu as well as the export rates for DER customers on the Customer Grid Supply (CGS) and Customer Grid Supply Plus (CGS+) tariffs. Notably, the levelized energy price of renewables, as well as the post-net energy metering DER tariffs, all come in below HECO's avoided cost today.[7]

**Figure 1. Energy Prices ($/kWh) for Renewable Energy on Oahu (2010 - 2018) Compared to Avoided Costs[8]**

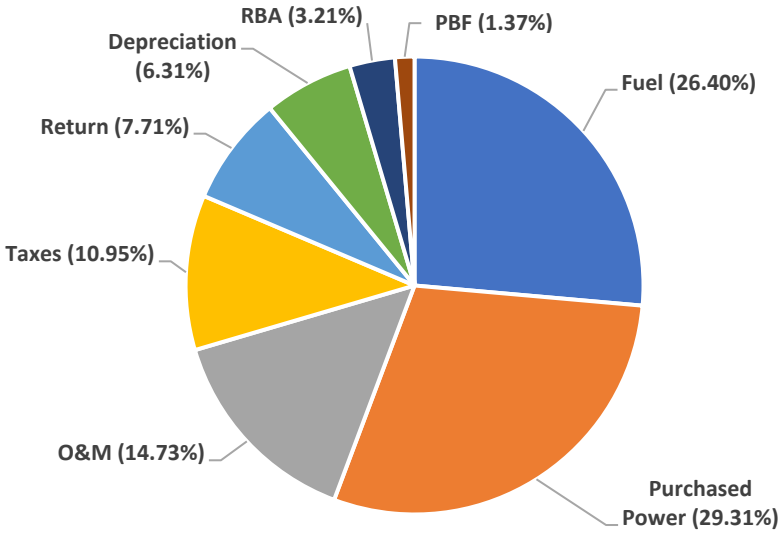

[7]Staff notes that HECO's Smart Export tariff compensates Oahu customers at roughly $0.15/kWh from 4:00 PM to 9:00 AM, with no export credit given from 9:00 AM to 4:00 PM.

[8]*See* HECO's Avoided Cost Table, *available at* https://www.hawaiianelectric.com/documents/billing_and_payment/rates/avoided_energy_cost/avoid

*Lower and More Stable Customer Bills*

Fuel and purchased power are the two largest cost drivers of customer rates.[9] In fact, fuel and purchased power cost components, on average, contribute to approximately half of total rates.[10]

**Figure 2. HECO Customer Rates Major Cost Components (Percentages) for 2018 (Q3)**




By replacing fossil fuel power plants with renewable energy resources, the fuel cost component will decrease as a percentage of total costs. Although purchased power will likely increase as a percentage of total costs, recent pricing trends suggest that the cost per kWh should decrease significantly. This, in turn, provides ample opportunity for lower and more stable electric rates.[11] Moreover, moving from fossil-fuel power plants to cost-effective renewable energy resources

_energy_cost_table.pdf; HECO Companies News Release, "New solar-plus-storage projects set low-price benchmark for renewable energy in Hawaii: Seven contracts submitted to regulators for review," January 3, 2019 (showing cost per kWh on Oahu ranging from $0.09 to $0.10), *available at* https://www.hawaiianelectric.com/new-solar-plus-storage-projects-set-low-price-benchmark-for-renewable-energy-in-hawaii.

[9]In 2017, the HECO Companies spent nearly $590 million on fuel alone. *See* Hawaiian Electric Industries' 2017 Annual Financial Report at 94.

[10]For Oahu, from the first quarter of 2015 to the third quarter of 2018, on average, fuel was approximately 22% of customers' electric rate. Together, purchased power and fuel totaled approximately half (or $0.13/kWh) of the customer rate, on average. These figures largely hold true across the remainder of the Companies' service territory as well. *See* HECO Companies' Key Performance Metrics, Rates and Revenues, *available at* https://www.hawaiianelectric.com/about-us/key-performance-metrics/rates-and-revenues.

[11]While purchased power prices are generally fixed over the term of the approved PPA, fossil fuel costs are subject to wide fluctuations in market prices. Moreover, given that petroleum fuels constitute approximately 60% to 80% of the Companies' fuel mix, this makes customer rates increasingly susceptible to volatile oil prices.

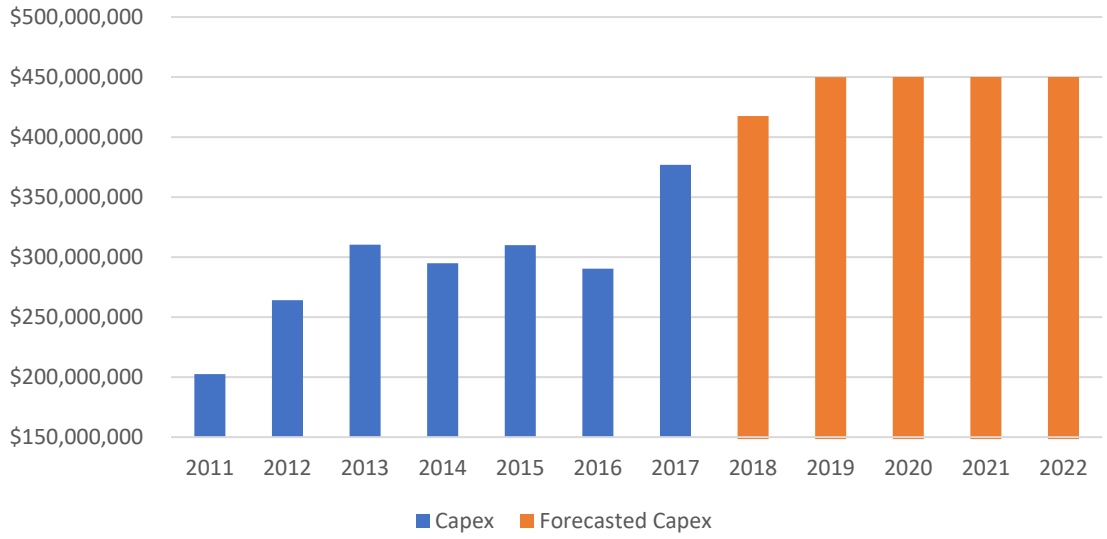
will provide a host of additional benefits, such as reduced carbon emissions; increased energy independence and resilience; as well as meaningful progress toward the state's RPS goal.

Accordingly, a focus of the PBR proceeding is to examine ways in which the regulatory framework might better incent the utilities to expeditiously integrate new, cost-effective renewables in their resource portfolio, to the benefit of all customers.

### 1.2.2 Managing Capital Expenditures

The traditional regulatory model for electric utilities may exert an "infrastructure bias" to deploy capital-intensive solutions.[12] Generally, there are few financial incentives for the utility to employ cost-savings measures, to reduce electricity sales, to improve energy efficiency, to increase customer choice, to integrate customer-sited generation, or to establish new and innovative services, except to the extent that utility capital investment is required.[13] The lack of financial incentives motivating utility investment in achieving these key outcomes adds to the challenge faced by regulators, who must find other means to ensure utility alignment with public policy and priorities.

**Figure 3. HECO Companies Capital Expenditures (Net of CIAC)**




Indeed, the HECO Companies' planned capital expenditures are expected to increase their rate base between 4-7% in 2019 and between 5-8% in 2020.[14] Naturally, growth in the rate base will

[12] *See* Harvey Averch and Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, THE AM. ECON. REV. 1052-1069 (1962).

[13] *But see* Steve Kihm, Janice Beecher, and Ronald Lehr, *Regulatory Incentives and Disincentives for Utility Investments in Grid Modernization,* FUTURE ELEC. UTIL. REG. NO. 8 (2017).

[14] *See* Hawaiian Electric Industries, Inc. Third Quarter 2018 Earnings Call Slide Deck, Slide 16, *available at* http://www.hei.com/Cache/1500114861.PDF?O=PDF&T=&Y=&D=&FID=1500114861&iid=1031123.

place upward pressure on rates. In a high-rate environment such as Hawaii, this trend and its impact on customer bills, will remain an area of focus and concern.

Prudent investments are undoubtedly necessary for the continued provision of safe and reliable electricity to customers in Hawaii. Nevertheless, it is paramount that the Companies make efficient investments that are in the public interest. To that end, the HECO Companies should be properly incented to identify and implement non-capital solutions where such solutions can deliver greater value to customers.

### 1.2.3 Reducing Operational Expenses

In addition to opportunities for cost control in the utility's capital expenditures, there is a significant need and opportunity for the HECO Companies to contain their operations and maintenance (O&M) expenses.[15]

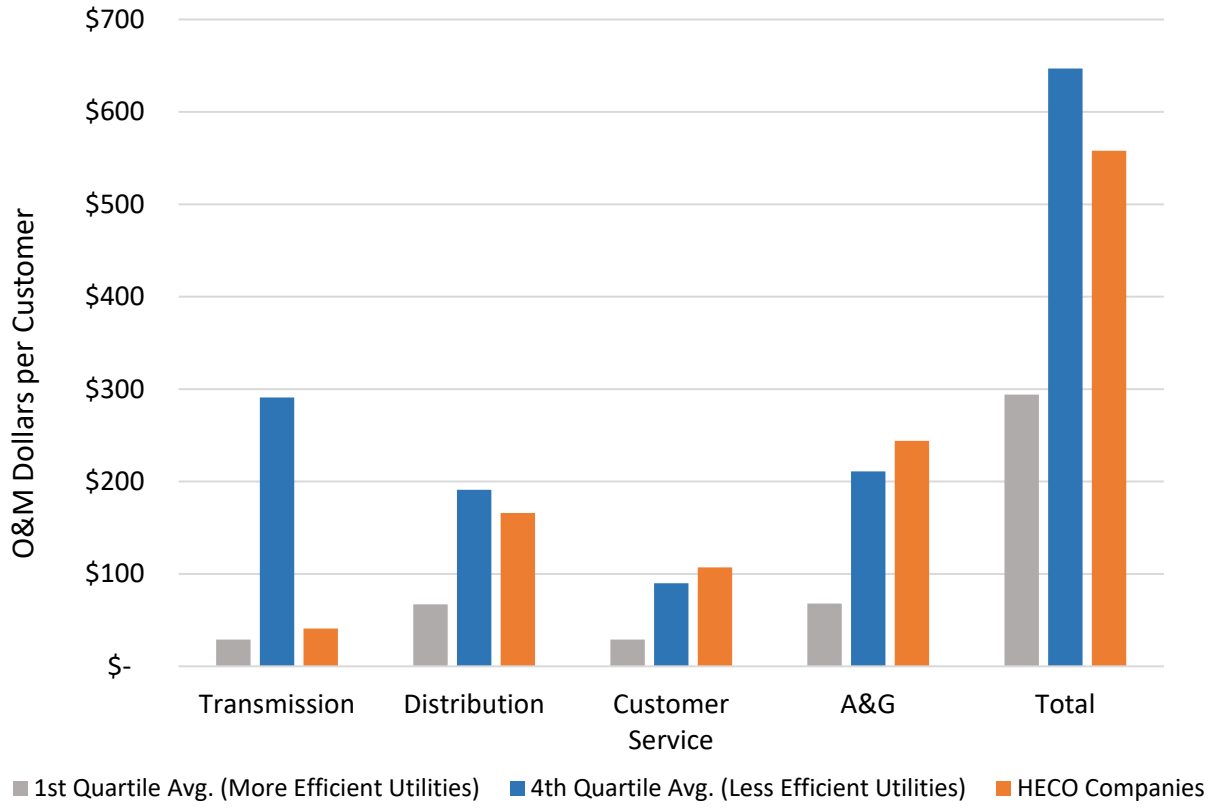
Figure 4 shows how the HECO Companies compare to other utilities in the U.S. A full list of the companies included in this comparison, along with their O&M expenses on a dollar per customer basis, is provided in Appendix C.[16] For the Transmission expense category, the HECO Companies are in the 1st quartile in the list of 127 utilities, ranking 28, representing fairly efficient performance compared to many other utilities. For the Distribution expense category, HECO sits in the 4th quartile and ranks 97 out of 127. For both Customer Service and A&G expense categories, HECO ranks 123 out of 127, making it one of the least efficient utilities on a dollar per customer basis. Overall, for non-fuel O&M expenses, the HECO Companies rank 106 out of the 127 utilities reported.[17]

[15]The Commission has previously expressed concern about the growth in HECO's expenses. *See In re Application of Hawaiian Electric Company, Inc. for Approval of General Rate Case and Revised Rate Schedules/Rules*, Docket No. 2016-0328, Decision and Order No. 35545, filed June 22, 2018, at 39.

[16]Although all the utilities included in this analysis may not be directly comparable to the HECO Companies in terms of size and market structure, the assessment of utility O&M expenses on a dollar per customer basis provides a useful comparison.

[17]Note that O&M expenses for generation were not included in this comparative analysis as many mainland utilities are restructured and do not own generation. In addition, it is important to recognize that a high customer service expense is not necessarily bad. The key is to ensure that customer service expenditures provide customer value.

**Figure 4. 2017 Average Annual O&M Per Customer: HECO Companies vs. 126 Mainland Subsidiary Companies**




The HECO Companies' non-fuel O&M expenses have substantially increased despite declining sales during that same time period.[18] This trend will remain an area of focus for the Commission going forward.[19]

## 1.3 CONCLUSION

The above factors highlight the imperative and opportunity in adapting the regulatory framework to ensure that utility business interests are properly aligned with customer interests and that incentives are calibrated to support the unfolding energy transition. An updated PBR framework can catalyze and enhance these opportunities, while maintaining utility financial health, realizing state policy goals, and delivering significant value to customers.

[18]Source: Derived from HECO, MECO, HELCO Annual Financial Reports 2009-2017.

[19]The Commission has previously expressed concern about HECO's growth in expenses, warning that "continued growth in expenses and plant additions could ultimately impose a burden upon the Company and its ratepayers." *In re Application of Hawaiian Electric Company, Inc. for Approval of General Rate Case and Revised Rate Schedules/Rules*, Docket No. 2016-0328, D&O No. 35545, filed June 22, 2018, at 39.

# 2 EXECUTIVE SUMMARY

The Commission, in April 2018, initiated a proceeding to investigate performance-based regulation ("PBR") (Docket No. 2018-0088) to explore new opportunities for evaluating and updating the state's regulatory framework in light of a transforming electric power system.

To best achieve these objectives, the Commission set out a two-phase process. Through Phase 1 of the proceeding, the Commission has established a collaborative stakeholder process according to a three-step conceptual framework: (1) identify priority goals and outcomes to guide PBR development, (2) characterize and assess the existing regulatory framework, and (3) identify changes to regulatory components and measures necessary to attain identified goals and outcomes. Phase 2 of this proceeding will focus on design and implementation of new or updated regulatory mechanisms to achieve the priority outcomes identified in Phase 1.

Building on significant input from Parties during Phase 1, this Staff Proposal outlines a suggested portfolio of PBR elements ("Staff Framework") to effectively and holistically drive achievement of twelve priority outcomes identified for continued attention. The Staff Framework recommends adoption of PBR tools to better align the HECO Companies' business interests with Hawaii's energy needs and customer preferences. Instead of the current approach that ties utilities' profits to the amount of capital investment, the proposed performance-based structure would set a target revenue amount that encourages immediate cost savings for customers. The utility would have the opportunity to earn additional performance revenue if it achieves identified objectives, including customer engagement and DER performance. Earnings would be shared with utility customers in a way that maintains the utility's financial health—while passing cost savings on to customers.

Specifically, the Staff Proposal:

- Provides background regarding the need to update the utility regulatory framework (Section 1);
- Recommends twelve priority outcomes to guide the remainder of this proceeding (Section 3); and
- Recommends a portfolio of PBR elements (Section 4).

## 2.1 Regulatory Goals and Prioritized Outcomes for Utility Regulation

In Phase 1, significant attention was devoted to the identification, examination and determination of regulatory goals and priority outcomes to guide the development of changes to utility regulations. Informed by the Parties' input, staff recommends three overarching regulatory goals and twelve priority outcomes to guide the remainder of this proceeding.

| Regulatory Goal | Regulatory Outcome | |
|---|---|---|
| Enhance Customer Experience | Traditional | Affordability |
| | | Reliability |
| | Emergent | Interconnection Experience |
| | | Customer Engagement |
| Improve Utility Performance | Traditional | Cost Control |
| | Emergent | DER Asset Effectiveness |
| | | Grid Investment Efficiency |
| Advance Societal Outcomes | Traditional | Capital Formation |
| | | Customer Equity |
| | Emergent | GHG Reduction |
| | | Electrification of Transportation |
| | | Resilience |

## 2.2 Updated Performance-Based Regulation to Achieve Priority Outcomes

In addition to supporting the goals and priority outcomes that have been identified and affirmed through Phase 1, the Staff Framework was developed with attention to three guiding principles:

1. **A customer-centric approach:** including meaningful, verifiable "day-one" savings for utility customers;

2. **Administrative efficiency:** to reduce regulatory burdens and costs to the utility, stakeholders, and customers; and

3. **Utility financial integrity:** to maintain the utility's financial health and economically facilitate Hawaii's clean energy transition.

The Staff Framework includes elements that provide meaningful financial upside opportunities for the utility along with common-sense "guardrails" to protect utility financial integrity on one hand, and prevent excessive utility earnings on the other.

The following table summarizes the core components of the proposed Staff Framework. The PBR elements are organized according to three categories of regulatory mechanisms: (1) revenue adjustment mechanisms; (2) performance mechanisms; and (3) other regulatory mechanisms. For details of the proposed Staff Framework, see Section 4.

| **Revenue Adjustment Mechanisms** | |
|---|---|
| **Multi-Year Rate Plan (MRP) and Indexed Revenue Cap** | **5-Year Control Period** with **Externally-Indexed Revenue Cap** allowing interim adjustments pursuant to a revenue cap index formula:<br>**RevCapIndex** = (**Inflation**) - (**X-Factor**) + (**Z-Factor**) - **Consumer Dividend**[20] |
| **Revenue Decoupling** | Continue to utilize **revenue decoupling** (i.e., the Revenue Balancing Account ["RBA"]), to true up revenues to an annual revenue target, which ensures the utility receives the target revenue, regardless of increases or decreases in energy sales |
| **Earnings Sharing Mechanism (ESM)** | Apply a modified **ESM** that provides both "upside" and "downside" sharing of earnings between the utility and customers when earnings fall outside a Commission-approved range |
| **Performance Mechanisms** | |
| **Performance Incentive Mechanisms (PIMs)** | Implement a set of **PIMs** designed to help drive achievement of the following priority outcomes: *Reliability; Interconnection Experience*; *Customer Engagement*; and *DER Asset Effectiveness* |
| **Scorecards** | Design and publish **Scorecards** with targeted performance levels to track progress against the following priority outcomes: *Interconnection Experience*; *Customer Engagement*; *Cost Control*; and *GHG Reduction* |
| **Reported Metrics** | Develop a portfolio of **Reported Metrics** to highlight activities under the following priority outcomes: *Affordability*; *Customer Equity*; *Electrification of Transportation*; *Capital Formation*; and *Resilience* |

[20]Where: Revenue Cap Index: Percent change allowed in total annual revenues; Inflation: Percent change in a published inflation index; X-Factor: Predetermined annual productivity factor; Z-Factor: Factor applied (ex post) to account for exceptional circumstances not in utilities direct control (e.g., tax law changes); and, Consumer Dividend Factor: A "stretch factor" or reduction (e.g., 0.5%) in allowed revenues. *See* Section 4.2.2.

| Other Regulatory Mechanisms | |
|---|---|
| **Capex/Opex Equalization** | Offer one or more **shared savings mechanisms** and explore development of other approaches to equalize treatment of capex/opex, such as a **return on service-based solutions** and the **capitalization of prepaid contracts** |
| **Innovation** | Develop one or more of the following mechanisms to support utility and third-party innovation: expedited **innovative pilot process**; a web-based **innovation platform**; and an **innovation fund** |
| **Platform Service Revenues** | Examine how **platform service revenues** can be incorporated into the regulatory framework, leveraging the experience of other jurisdictions where appropriate |

To provide cost reduction incentives, staff proposes suspending the existing triennial rate case cycle, to be replaced with a five-year multi-year rate plan ("MRP"). The extended five-year control period of the MRP is intended to amplify the cost containment incentives provided by an index-driven revenue cap. Allowed revenues in the interim years of the MRP would be adjusted by an externally-indexed revenue cap formula, rather than by the utility's actual costs.

In addition to incentives for cost reductions, the Staff Framework is designed to support new utility earnings opportunities as an incentive to achieve exemplary performance and business innovation. Staff proposes a portfolio approach to performance mechanisms, to be further developed in Phase 2, including Reported Metrics, Scorecards, and Performance Incentive Mechanisms ("PIMs"). Staff proposes that PIMs be developed (and maintained or amended where they already exist) to support at least four priority outcomes: *Reliability*, *Interconnection Experience*, *Customer Engagement*, and *DER Asset Effectiveness*.

In order to maintain reasonable utility earnings, the Staff Framework includes an earnings sharing mechanism ("ESM") to provide both "upside" and "downside" sharing of future earnings between the utility and customers when earnings fall outside a Commission-approved range. An ESM, along with other mechanisms that account for exceptional or extreme circumstances, can help ensure that utility earnings do not excessively benefit or suffer from external factors outside of utility control, or from unforeseen results of regulatory mechanisms.

Beyond suggestions for revenue mechanisms and performance mechanisms, several Parties have expressed the need to reduce an existing utility preference to maintain and increase utility rate base through capital expenditures. Staff recommends further examination of options to address this capital bias in Phase 2, including a particular focus on shared savings mechanisms as well as approaches that allow the utility to earn a return on service-based solutions.

To support a continued transition toward a modern, customer-oriented business, the HECO Companies will need to foster innovation and design solutions outside of business-as-usual. This will likely require alternative mechanisms and new processes. A number of activities have emerged around the world to encourage electricity system innovation, including: expedited process for pilot implementation; web-based innovation platform; and an innovation fund.

Similarly, there is merit to the concept of a platform-based utility that integrates and coordinates energy service provision between customers and third-party service providers. Platform service revenues, coupled with other regulatory activities (see Appendix D), are a means to encourage evolution toward a platform-based business model. Staff recommends further development of platform revenue opportunities through Phase 2.

## 2.3 NEXT STEPS

As next steps, Parties are asked to submit, by March 8, 2019 their Statements of Position ("SOPs") that focus on providing feedback to this Staff Proposal. Additionally, Parties will have the opportunity to file limited information requests as to each other's SOP by March 18, 2019, with responses due by March 25, 2019. Finally, Parties may submit Reply SOP by April 5, 2019.

Following which, the Commission intends to issue a decision and order to conclude Phase 1 of this proceeding.

# 3 REGULATORY GOALS AND OUTCOMES TO GUIDE PBR IN HAWAII

## 3.1 GOALS AND OUTCOMES: FOUNDATION FOR PBR DEVELOPMENT

The steps of this proceeding have followed a conceptual framework that can be used to transform broad policy goals into actionable outcomes for utility operations and the delivery of energy services. The process framework is meant to be thorough and transparent, with opportunities for consensus-building throughout.

G*oals* provide the highest-level orientation for what utility regulations and ratemaking seek to achieve. Regulatory goals for PBR development anchor and inform consideration of specific outcomes that result from the regulated utility system.[21] Traditional cost-of-service utility regulation has long held a goal to deliver reliable, affordable electricity to all customers through prudently incurred investments and efficient utility business operations. Over time, goals for the power sector have expanded to include a broader set of customer and public policy oriented objectives, including customer engagement, innovation, environmental performance, and competition.

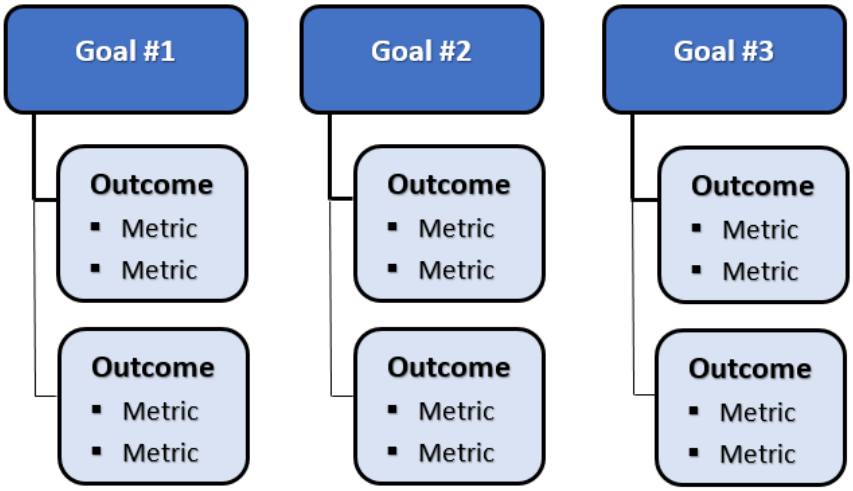
*Outcomes* are a more specific set of factors that derive, in whole or in part, from utilities' operations and business decisions. Outcomes represent the many ways that the power sector is experienced by customers and market participants, as well as throughout the economy and society at large. Outcomes are usually observable, whether through quantitative or qualitative measures, and in many cases can be measured through one or more *metrics*.

The next level in the hierarchy, a *metric*, simply defined, is a standard of measurement. In assessing utility and market performance, metrics are fundamental to determine how well a utility is achieving the outcomes of interest and meeting the broader goals set by regulators and policymakers.[22] Metrics are discussed further in Section 4.2.3.

[21]Docket No. 2018-0088, "Goals and Outcomes for Performance-Based Regulation in Hawaii: Concept Paper to Support Docket Activities," filed July 10, 2018 ("Staff Report #1"), at 9.

[22]Whited, M., Woolf, T., Napoleon, A. *Utility Performance Incentive Mechanisms: A Handbook for Regulators*, Synapse Energy Economics, March 2015, ("Synapse Report") at 19.

**Figure 5. Goals-Outcomes-Metrics Hierarchy**




## 3.2 THREE REGULATORY GOALS TO GUIDE PBR IN HAWAII

By this Proposal, staff recommends that the Commission adopt the following three overarching goals to guide development of a comprehensive PBR framework.[23]

**Enhance Customer Experience:** Delivering affordable and reliable service to customers has always been a core utility responsibility. Needs and expectations are changing, however, as customers transform from passive consumers of energy to active participants in the electricity system. Utilities should be expected to facilitate additional choices and options for customers as they interact with service providers to procure DER and other services and seek to dynamically manage their energy use and costs.

**Improve Utility Performance:** Optimizing utility planning processes, investment choices, and system operations ensures that utilities make and implement decisions necessary to provide exemplary service at the least cost to customers. As Hawaii's energy portfolio becomes

[23] In support of this recommendation, staff observes that there appears to be general agreement among the Parties for these three overarching goals. *See, e.g.*, Docket No. 2018-0088, "Ulupono Initiative LLC's Brief on Goals and Outcomes and Certificate of Service," filed August 27, 2018 ("Ulupono's Brief #1") at 2; Docket No. 2018-0088, "Hawaii PV Coalition Technical Workshop 1 – Goals and Outcomes Brief and Certificate of Service," filed August 27, 2018 ("HPVC's Brief #1") at 1; Docket No. 2018-0088, "Blue Planet Foundation's Goals-Outcomes Brief and Certificate of Service," filed August 27, 2018 ("Blue Planet's Brief #1") at 11 (believes these three goals are both appropriate and exhaustive); Docket No. 2018-0088, "Division of Consumer Advocacy's Goals-Outcomes Brief," filed August 31, 2018 ("Consumer Advocate's Brief #1") at 19-20; Docket No. 2018-0088, "Distributed Energy Resources Council of Hawaii's Goals and Outcomes Brief of the Commission's Staff Report #1 and Certificate of Service," filed August 27, 2018 ("DERC's Brief #1") at 5, 7, 8; Docket No. 2018-0088, "Goals-Outcomes Brief of the Hawaiian Electric Companies; Exhibits 1-4; and Certificate of Service," filed August 31, 2018 ("HECO Companies' Brief #1") at 3 ("The Companies are in support of and agree with many of the goals and outcomes identified in the Staff Report.").

increasingly renewable, diverse, and distributed, utilities will need to invest in a grid with greater capabilities. To protect customers from unnecessary rate increases or other costs resulting from these potentially large investments and new functions, utilities are expected to operate in an economically efficient and strategically effective manner.

**Advance Societal Outcomes:** To achieve Hawaii's ambitious clean energy goals and other policy objectives, there is a need to reevaluate underlying assumptions for how regulated utilities serve societal and public policy goals. Modern electricity needs extend beyond traditional objectives for universal, reliable, and affordable energy supply. Additional societal goals have been layered onto these, including environmental performance, market development, data sharing, transport electrification, and more.

## 3.3 Prioritized Outcomes to Inform Phase 2

Under each regulatory goal are a number of outcomes, which reflect more specific factors that derive, in whole or in part, from utilities' operations and business decisions.

The Phase 1 Convening Order in this proceeding stated that the Commission and Parties will assess which outcomes are currently well-served by the regulatory framework and which require greater focus and examination, leading to a distilled set of outcomes to focus the proceeding going forward.[24] This process began with 29 possible outcomes offered in Staff Report #1, which Staff revised based on Party input during Phase 1, culminating in a suggested list of 12 priority outcomes in Staff Report #3.[25]

To help further clarify and support continued consideration, the proposed outcomes are sorted into two categories: "traditional" and "emergent."[26] Traditional outcomes have been ingrained in utility regulations for many years and, while not immutably achieved or secured in current regulations, they are at least partially addressed. Emergent outcomes include those that need attention as Hawaii progresses towards a 100% RPS, as the electricity system becomes more renewable and distributed, and as the HECO Companies pursue opportunities for non-traditional asset investments and services. Notwithstanding the critical importance of traditional outcomes, it is suggested that, given the significant energy transition underway in Hawaii, the near-term focus in this proceeding should, on balance, be placed somewhat more on emergent outcomes.

Based on the Parties' input and feedback to date, staff recommends the Commission adopt the following prioritized outcomes to guide the remainder of this proceeding in Phase 2. Descriptions of each outcome are offered in Appendix A.

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[24]Docket No. 2018-0088, Order No. 35542, filed June 20, 2018 ("Phase 1 Convening Order").

[25]Docket No. 2018-0088, "Prioritized Outcomes, Regulatory Options, and Metric Development for Performance-Based Regulation in Hawaii: Concept Paper to Support Docket Activities," filed November 14, 2018 ("Staff Report #3").

[26]Some parties have proposed similar organizing principles and criteria for prioritized outcomes; *see, e.g.*, HECO Brief #2 at 2-3, Ulupono Brief #2 at 3.

**Table 1. Recommended Priority Outcomes**

| Regulatory Goal | Regulatory Outcome | |
|---|---|---|
| Enhance Customer Experience | Traditional | Affordability |
| | | Reliability |
| | Emergent | Interconnection Experience |
| | | Customer Engagement |
| Improve Utility Performance | Traditional | Cost Control |
| | Emergent | DER Asset Effectiveness |
| | | Grid Investment Efficiency |
| Advance Societal Outcomes | Traditional | Capital Formation |
| | | Customer Equity |
| | Emergent | GHG Reduction |
| | | Electrification of Transportation |
| | | Resilience |

## 3.4 Mapping Priority Outcomes to Regulatory Mechanisms

Having established a focused set of outcomes, the next step in the Phase 1 process is to match each of the prioritized outcomes to one or more corresponding categories of regulatory mechanisms. The selected regulatory mechanism categories should reflect those that are best able to drive achievement of the outcome. Mapping outcomes to categories of regulatory mechanism will provide a focused foundation for success in Phase 2, where the design and development of specific PBR elements to drive achievement toward each outcome will occur.

**Categories of Regulatory Mechanisms**

Prioritized outcomes can be mapped to three categories of regulatory mechanism: (1) revenue adjustment mechanisms; (2) performance mechanisms; and (3) other regulatory mechanisms. Each category is described further below.

**Revenue Adjustment Mechanisms**

Some prioritized regulatory outcomes can be best addressed through the use of revenue adjustment mechanisms. Revenue adjustment mechanisms may be preferred to other categories, such as performance mechanisms, where the desired outcome relates to a utility's underlying structural incentives or where a single corresponding metric is difficult to determine or measure. Various jurisdictions have utilized revenue adjustment mechanisms such as multi-year rate plans coupled with attrition relief mechanisms to incent cost control between rate periods.

**Performance Mechanisms**

Performance mechanisms include possible regulatory tools such as Reported Metrics, Scorecards, and PIMs. Performance mechanisms can provide more narrowly focused inducement to support outcomes that may not be adequately addressed by a utility's underlying structural incentives. PIMs, in particular, can be an effective way to link utility revenue or earnings to performance in targeted areas.

**Other Regulatory Mechanisms**

In cases where certain regulatory outcomes are not sufficiently addressed by either of the above regulatory mechanisms, it may be necessary to review and consider strategic changes to the current regulatory framework. This could include mechanisms that help move away from the existing capital investment compensation paradigm (e.g., developing mechanisms to encourage the pursuit of cost-effective, service-based solutions). Other options may include new revenue opportunities to enable a future electric utility platform business model (e.g., provision of new value-added services to customers and third-parties).

By Table 2 below, staff provides its recommendation for how the priority outcomes set forth above map to one or more of three broad categories of regulatory mechanisms. Staff further provides a recommendation for which specific regulatory mechanisms might be utilized under each category to drive achievement of the corresponding prioritized outcome.

**Table 2. Mapping Outcomes to Specific Regulatory Mechanisms**

| Goal | Outcome | Mechanism Category | Regulatory Mechanisms |
|---|---|---|---|
| **Enhance Customer Experience** | Affordability | Revenue Adjustment Mechanism | MRP / ARM (Indexed Revenue Cap) |
| | | Performance Mechanism | Reported Metric |
| | Reliability | Performance Mechanism | PIM |
| | Interconnection Experience | Performance Mechanism | Scorecard |
| | | | PIM |
| | Customer Engagement | Performance Mechanism | Scorecard |
| | | | PIM |
| **Improve Utility Performance** | Cost Control | Revenue Adjustment Mechanism | MRP / ARM (Indexed Revenue Cap) |
| | | Performance Mechanism | Scorecard |
| | | Other | Capex/Opex Equalization (e.g., Shared Savings) |
| | DER Asset Effectiveness | Revenue Adjustment Mechanism | MRP / ARM (Indexed Revenue Cap) |
| | | Performance Mechanism | PIM |
| | | Other | Planning (e.g., IGP) |
| | Grid Investment Efficiency | Revenue Adjustment Mechanism | MRP /ARM (Indexed Revenue Cap) |
| | | Other | Capex/Opex Equalization (e.g., Shared Savings) |

| Goal | Outcome | Mechanism Category | Regulatory Mechanisms |
|---|---|---|---|
| **Advance Societal Outcomes** | Customer Equity | Performance Mechanism | Reported Metric |
| | | Other | LMI-focused Programs |
| | GHG Reduction | Performance Mechanism | Scorecard |
| | Electrification of Transportation | Performance Mechanism | Reported Metric |
| | | Other | New value-added services |
| | Capital Formation | Performance Mechanism | Reported Metric |
| | Resilience | Performance Mechanism | Reported Metric |
| | | Other | Planning (e.g., IGP); Microgrid Service Tariff |

# 4 STAFF'S RECOMMENDED PBR FRAMEWORK

This section outlines a suite of PBR elements that should effectively and holistically drive achievement of the identified priority outcomes. This recommended PBR framework ("Staff Framework") builds upon the three Staff Reports and is informed by Party input throughout Phase 1, particularly, the Parties' briefs filed on January 4, 2019.

The Staff Framework is intended to facilitate establishment of a comprehensive PBR framework in Phase 2 of this proceeding, by outlining staff's current perspectives, and providing a proposal for comment and discussion by the Parties. The Staff Framework does not constitute any findings by the Commission regarding the ultimate scope or content of a PBR framework for the HECO Companies. That said, the Staff Framework is offered to advance the conversation through the end of Phase 1.

## 4.1 GUIDING PRINCIPLES

In addition to the considerations noted above, the development of the Staff Framework was informed by several guiding principles, including the following:

**Customer-Centric Approach**

A PBR framework should encourage the expanding opportunities for customer choice and participation in all appropriate aspects of utility system functions.

The details of a PBR framework will influence the allocation of realized cost savings and other benefits between utilities and their customers. **Staff recommends that any PBR framework to emerge from this proceeding include meaningful, verifiable, day-one savings for all customers.** There are various mechanisms by which such savings could be ensured in a comprehensive PBR framework, including through one or more benefit sharing provisions under a multi-year rate plan.[27]

**Administrative Efficiency**

Staff acknowledges that the current regulatory framework is relatively complex, and its administration is resource intensive for the HECO Companies, the Consumer Advocate, and the Commission alike. PBR offers an opportunity to simplify the regulatory framework and enhance overall administrative efficiency. The PBR framework adopted in this proceeding should serve to simplify rather than complicate the regulatory process and thereby reduce regulatory costs to the utility and its customers.

**Utility Financial Integrity**

From the inception of utility regulation, a fundamental goal has been to ensure the utility's financial health. As several Parties have noted, the financial integrity of the utility is essential to its basic obligation to provide safe and reliable electric service for its customers.[28] Moreover, the utility is a critical community partner and serves an integral role in achieving the state's energy policy goals and serves as an essential credit-worthy off-taker for contracts for non-utility power purchases and new evolving grid services providers. The proposed Staff Framework will help to reduce regulatory lag and preserve the utility's opportunity to earn a fair return on its business and investments, while maintaining attractive utility features, such as access to low-cost capital.

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[27] *See* Mark Newton Lowry and Lawrence Kaufmann, "Performance-Based Regulation of Utilities," Energy Law Journal, Vol 23:399 2002, at 436-37 ("Lowry-Kaufmann Article").

[28] *See* HECO Companies Brief #3 at 11 (discussing the relationship between credit rating, innovation, and capital formation), 73-74 (expressing concern about proposed treatment of financial integrity); Consumer Advocate Brief #3 at 13 (discussing the importance of ensuring that the utility is able to attract equity and debt at reasonable costs), 20-21 (proposing an ESM to ensure financial outcomes within acceptable ranges of ROE); Ulupono Brief #3 at 18 (discussing protection of the utility's financial integrity through a modified earnings sharing mechanism), 21,28 (discussing Ulupono's plan to develop a financial model that tests the impact of PIMs on financial performance, including capital formation and cash flows).

## 4.2 STAFF FRAMEWORK ELEMENTS

### 4.2.1 Summary

Informed by the guiding principles outlined above, and intended to drive achievement of the priority outcomes, staff offers a comprehensive PBR framework designed to incent cost control, enhance customer choice, and accelerate progress toward state clean energy goals. The Staff Framework includes a combination of specific recommendations regarding several elements of a revised regulatory regime, and identification of elements for which further examination is required in the remainder of Phase 1 and Phase 2.

The proposed update to utility ratemaking can be described by the following illustrative formula:

**Utility Revenue = (Target Revenues + Performance Revenues) +/- Earnings Sharing**

Each part of this representative formula includes sub-components to support appropriate capital and operational expenses, as well as cost trackers and automatic adjustments to encourage prudent utility business practices while investing in a clean energy future.

Table 3, below, provides a summary view.

**Table 3. Staff Framework Summary**

| **Revenue Adjustment Mechanisms** | |
|---|---|
| **Multi-Year Rate Plan (MRP) and Indexed Revenue Cap** | **5-Year Control Period** with **Externally-Indexed Revenue Cap** allowing interim adjustments pursuant to a revenue cap index formula:<br><br>**RevCapIndex** = (**Inflation**) - (**X-Factor**) + (**Z-Factor**) - **Consumer Dividend** |
| **Revenue Decoupling** | Continue to utilize **revenue decoupling** (i.e., the Revenue Balancing Account ["RBA"]), to true up revenues to an annual revenue target, which ensures the utility receives the target revenue, regardless of increases or decreases in energy sales |
| **Earnings Sharing Mechanism (ESM)** | Apply a modified **ESM** that provides both "upside" and "downside" sharing of earnings between the utility and customers when earnings fall outside a Commission-approved range |

| Performance Mechanisms | |
|---|---|
| **Performance Incentive Mechanisms (PIMs)** | Implement a set of **PIMs** designed to help drive achievement of the following priority outcomes: *Reliability; Interconnection Experience*; *Customer Engagement*; and *DER Asset Effectiveness* |
| **Scorecards** | Design and publish **Scorecards** with targeted performance levels to track progress against the following priority outcomes: *Interconnection Experience*; *Customer Engagement*; *Cost Control*; and *GHG Reduction* |
| **Reported Metrics** | Develop a portfolio of **Reported Metrics** to highlight activities under the following priority outcomes: *Affordability*; *Customer Equity*; *Electrification of Transportation*; *Capital Formation*; and *Resilience* |
| **Other Regulatory Mechanisms** | |
| **Capex/Opex Equalization** | Offer one or more **shared savings mechanisms** and explore development of other approaches to equalize treatment of capex/opex, such as a **return on service-based solutions** and the **capitalization of prepaid contracts** |
| **Innovation** | Develop one or more of the following mechanisms to support utility and third-party innovation: expedited **innovative pilot process**; a web-based **innovation platform**; and an **innovation fund** |
| **Platform Service Revenues** | Examine how **platform service revenues** can be incorporated into the regulatory framework, leveraging the experience of other jurisdictions where appropriate |

### 4.2.2 Revenue Adjustment Mechanisms

*Overview*

PBR frameworks typically include some combination of revenue adjustment mechanisms that modify and/or cap the level of allowed utility revenues between rate plan periods.

*Multi-Year Rate Plan ("MRP")*: a fixed, extended interim period without general rate cases in which utility revenues are determined by some combination of attrition relief mechanisms, performance mechanisms, and cost trackers.

*Revenue Cap and Attrition Relief Mechanism ("ARM")*: a mechanism that adjusts allowed utility revenues in an interim period without general rate cases (i.e., the MRP control period) according to a defined formula and specific determinants. Indexed-based ARMs compensate utilities automatically for important external cost drivers such as inflation.

*Revenue Decoupling*: a mechanism that ensures that changes in revenue determinants such as sales and demand, that do not adversely affect utility revenue.

*Earnings Sharing Mechanism ("ESM")*: a mechanism that serves to "share" amounts of utility company earnings that deviate substantially from the level of earnings determined to be reasonable in setting utility revenues and rates.

*Efficiency Carryover Mechanism ("ECM")*: a mechanism that enables utilities to benefit from efficiency gains throughout and across MRP periods by allowing utilities to receive benefits for a specified carryover period regardless of when the saving was made.

*Consumer Dividend*: a feature of revenue cap regimes to ensure there is an advance commitment to customer benefits.

*Adjustment of Initial Rates*: reduction in the allowance of utility revenues at the commencement of an MRP control period to ensure customer benefits

*Cost Trackers*: mechanisms, such as fuel cost adjustment and purchased power adjustment mechanisms, that pass actual realized utility expenses directly to customers in the interim periods between general rate cases.

*Off-ramp Mechanism*: an option that permits reconsideration of an MRP under pre-specified conditions.

*Staff Recommendation*

The regulatory framework for the HECO Companies currently includes several revenue adjustment mechanisms, including a three-year rate case cycle for each utility, with cost trackers for fuel and purchased energy and capacity costs, a revenue decoupling mechanism, and a rate adjustment mechanism that provides annual revenue adjustments for O&M, rate base and depreciation expenses. Outside of certain cost trackers like fuel and purchased power, annual revenue adjustments are capped at the rate of inflation and are limited by an "upside only" ESM. These existing regulatory components are described briefly below, along with the staff's recommendations for changes and additional components of the Staff Framework. A more complete description of the pertinent existing regulatory framework components is provided in Staff Report #2.[29]

Several priority outcomes, including *Affordability*, *Cost Control*, *Grid Investment Efficiency*, and *DER Asset Effectiveness*, can be addressed by modifications to existing mechanisms and adoption of new mechanisms that cap utility revenues and allow inflation-indexed adjustments during the control period.

[29] *See* Staff Report #2, at 16-23.

Staff recommends the following revenue adjustment mechanisms as part of the Staff Framework.

**A Five-Year MRP With Index-Driven Revenue Cap**

An *MRP* is a fixed, extended interim period without general rate cases in which utility revenues are determined by some combination of ARMs, performance mechanisms, and cost trackers. Each of the HECO Companies currently files a general rate case on a fixed three-year cycle.

An *ARM* adjusts allowed utility revenues in an interim period without general rate cases (i.e., the MRP control period) according to a defined formula and specific determinants. An existing Rate Adjustment Mechanism tariff ("RAM") for each of the HECO Companies provides for annual adjustments to allowed revenues for a combination of indexed and actual expenses for O&M, and changes in rate base and depreciation/amortization.

An MRP (fixed multi-year period without general rate cases) with an index-driven ARM serve as a fundamental driver of incentives for cost control. To the extent each utility can lower expenses during the MRP interim "control period," savings would be realized by the utility as increased earnings.

Staff recommends that the control period for the initial MRP be set at 5 years. A 5-year rate plan represents a balanced approach, weighing the need to have a longer control period to adequately amplify cost containment pressures, against concerns that too long of a control period would not permit adequate opportunities for course correction in a dynamic and rapidly changing regulatory environment. Staff notes that several Parties expressed support for a 5-year control period.[30]

Staff recommends an externally-indexed revenue cap regime, as generally supported by the Consumer Advocate,[31] Blue Planet,[32] and Ulupono.[33] Consistent with the Consumer Advocate's recommendation, staff recommends that the existing RAM Tariff determinations be discontinued and replaced with a single, index-driven mechanism to adjust target revenues, which is not affected by the actual costs incurred by the utility in interim periods. This recommended ARM

[30]Consumer Advocate Brief #3 at 48 (recommending a 5-year review window for MRP and PBR with an ESM) ; HECO Companies Brief #3 at 52 (expressing conditional support for 5-year control period); Blue Planet Brief #3 at 12 (recommending "[a]n extended control period between rate cases, e.g., at least 5 to 8 years"). Staff further observes that the UK's Ofgem is modifying its RIIO framework to move from an 8-year control period to a 5-year control period. *See* HECO Companies Brief #3 at 54.

[31]Consumer Advocate Brief #3 at 21 (Recommending "[a] scheduled [MRP] review proceeding, no less than five years after commencement, to investigate performance under the plan and explore potential improvements to the regulatory framework.")

[32]*See* Blue Planet Brief #3 at 13-14.

[33]*See* Ulupono Brief #3 at 39 ("Ulupono supports extension of the [MRP] beyond the current three-year period to approximately five years.")

approach would encourage the utilities to carefully manage both operating and capital expenditures.

Accordingly, the ARM implemented in conjunction with other components of the Staff Framework would terminate and replace the existing RAM and RAM Cap revenue adjustment provisions. Existing issues regarding regulatory lag in accrual of RAM revenue adjustments would also be eliminated.[34]

Staff recommends an ARM formula with determinants that are exogenous to utility performance and/or control. Performance-driven revenue adjustments would be applied as separate additional adjustments to allowed utility revenues.

Each year, allowed revenues would be adjusted in accordance with a Revenue Cap Index which would incorporate several adjustment components, including adjustments for inflation, productivity (X-Factor), exogenous factors (Z-Factor), and a Consumer Dividend.

**Revenue Cap Index = (Inflation) - (X-Factor) + (Z-Factor) - Consumer Dividend Factor**

Where:
Revenue Cap Index: Percent change allowed in total annual revenues
Inflation: Percent change in a published inflation index
X-Factor: Predetermined annual productivity factor
Z-Factor: Factor applied (ex post) to account for exceptional circumstances not in utility's direct control (e.g., tax law changes)
Consumer Dividend Factor: A reduction in allowed revenues; a "stretch factor"

A utility's expenses and revenues can be expected to increase with inflation, offset by increases in productivity that utilities (and all industries) experience. Productivity can flow from numerous factors, including technological improvements, workforce development, innovation, capital investment, and lower costs.

The inflation measure is often a macroeconomic price index such as the Gross Domestic Product Price Index ("GDPPI"); however, custom indexes of utility input price inflation are sometimes used in ARM design. The appropriate inflation measure will be an important consideration of Phase 2.[35]

The productivity, or "X" factor, usually reflects the average historical trend in the multifactor productivity of a group of peer utilities. Phase 2 will need to determine the appropriate value for

[34] *See* HECO Companies' Brief #3 at 52.

[35] *See* MN Lowry, M Makos, and J Deason, State Performance-Based Regulation Using Mutliyear Rate Plans for U.S. Electric Utilities, Grid Modernization Laboratory Consortium, U.S. Department of Energy, July 2017, ("Lowry-Makos MRP Report"), at 4.1-4.2.

X; however, base productivity trends chosen by North American regulators for X factor calibration have tended to lie in a fairly narrow range to date (e.g., zero to 1 percent).[36]

In the event some uncontrolled exogenous events affect a utility's costs (e.g., the "2017 Tax Cut and Jobs Act"), the Z-Factor in the formula allows for positive or negative revenue adjustments. Adjustments could include specifically approved adjustments to allowed revenues, including for example, revenues for major capital projects such as those provided in accordance with the existing MPIR Guidelines.

Finally, the Consumer Dividend is a feature to ensure that there is some "pay off" for customers. Since the annual change in revenues will nearly always be positive, a built-in consumer dividend ensures that rates are lower than otherwise, even if they are increasing. This effectively serves as a "stretch factor" that challenges utilities to become more efficient than the productivity index (i.e., X-factor).

The index-driven ARM outlined above would mitigate one aspect of the capital investment bias that exists under use of the existing regulatory structure, which allows interim return on rate base that includes revenue increases determined by new capital investments.[37] Ideally, a composite, index-driven ARM would encourage the utilities to seek economies based on optimal allocation of operating and capital expenditures.[38]

**Determination of Initial Base Revenues and Rates**

Staff recommends that the initial base revenues and rates for each utility MRP be set at the target revenues and rates in place (or pending determination in an open rate case) at the time the updated PBR framework becomes effective.[39] A new general rate case would not be required for each utility in order to commence implementation of any new PBR framework elements. A final order in this proceeding would address and determine specific details regarding necessary transitions from existing revenues and rates.

**Resetting Revenues and Rates**

The process and criteria to be used for re-determining revenues and rates at the end of the initial 5-year control period will need to be established in Phase 2. Considerations include: long- versus short-range incentive effects; the need to re-set base parameters and targets of PIMs; impacts

[36] *See* Lowry-Makos MRP Report, at 4.2.

[37] *See* Consumer Advocate Brief #3 at 29 n. 33 ("With rate cases suspended, only specific new capital investments that are approved in advance by the Commission, for recovery through the REIP or MPIR mechanisms, could be translated into increased target revenues outside of the indexed RAM.").

[38] Consumer Advocate Brief #3 at 29.

[39] The Consumer Advocate maintains that a main challenge of setting base revenues is identifying "to what extent are the existing 'inception' target revenues for each utility adequate or excessive on a going-forward basis." Consumer Advocate Brief #3 at 20-21

on incentives at the beginning versus the end of the control period changes; adjustments to rate design; and impacts of extended ARM and PIM revenue adjustments on effective rate design.[40]

**Decoupling**

Revenue Decoupling ensures that changes in revenue determinants such as sales and demand, which may be reduced by energy efficiency or DER adoption, do not adversely affect utility earnings.

Each of the HECO Companies has an existing Revenue Balancing Account Provision ("RBA") tariff, which ensures that each of the Companies will ultimately recover no more and no less than approved target revenue,[41] regardless of increases or decreases in energy sales or other billing determinants. Annual RBA rate adjustments are implemented to reconcile and ensure accurate recovery of RBA account balances.

As recommended by several Parties,[42] the Staff Framework would continue to utilize revenue decoupling through the existing RBA. The RBA would continue to serve as the mechanism for implementing adjustments to accrued revenues and reconciliation of collected utility revenues, including adjustments resulting from the ARM, PIMs, and other interim adjustments specifically ordered by the commission.

**Earnings Sharing Mechanism**

An *Earnings Sharing Mechanism ("ESM")* serves to "share" amounts of utility company earnings that deviate substantially from the level of earnings determined to be reasonable in setting utility revenues and rates.

The HECO Companies currently have an ESM as part of the RAM tariffs. The existing ESM serves as a ratepayer protection provision. To the extent that realized earnings (in terms of percent return on equity) exceed the "approved" levels in the most recent rate case, increasing proportions of the realized earnings are returned ("shared") with ratepayers as a credit towards future revenue collection.

[40]Blue Planet recommends that the Commission review the "revenue cap regime one year before it expires." To avoid capex bias, Blue Planet recommends that new rates should not be set based on rate base and rate-of-return. Blue Planet's Brief #3 at 20 (discussing consideration for how to proceed after the end of a "revenue control period").

[41]Target revenue is the approved revenue requirement determined in the most recent previous general rate case, minus revenues collected through revenue trackers (e.g., fuel and purchased power cost adjustment mechanisms) and adjusted by any of several existing mechanisms, including the RAM, PIM and MPIR mechanisms.

[42]*See* Blue Planet's Brief #3 at 15; Consumer Advocate's Brief #3 at 20, 30; HECO Companies' Brief #3 at 45 and 66 (recommending that RBA needs to be adjusted).

Staff recommends implementation of a revised ESM that provides both "upside" and "downside" sharing of earnings that fall outside of a Commission-approved range. The design of an ESM should be determined carefully, considering the overall framework of regulatory provisions, including the full portfolio of existing, modified, and new PBR mechanisms in effect. Some aspects of the design of an ESM may be incorporated in individual PIMs, such as limiting extreme financial impacts by providing "diminishing returns" as realized performance diverges more extremely from performance targets.[43]

The use of an ESM can lessen the downward cost pressure of an MRP. Accordingly, implementation of an ESM should consider the resulting effects of limiting the cost control incentives otherwise presented to the utility by the portfolio of existing, amended and new regulatory mechanisms.

**Efficiency Carryover Mechanism**

An *Efficiency Carryover Mechanism ("ECM")* enables utilities to benefit from efficiency gains throughout and across MRP periods by allowing utilities to receive benefits for a specified carryover period regardless of when the savings are made.[44]

Staff recommends consideration of an ECM mechanism in Phase 2. Considerations should include: the need to address incentives at the beginning versus near the end of an MPR control period; and the need to provide long-term cost control incentives and consistency with other PBR Framework elements, such as an ESM and provisions for resetting rates at the end of the MRP control period.

**Cost Adjustment Mechanisms (Cost Trackers)**

Cost Trackers are mechanisms, such as fuel cost adjustment and purchased power adjustment mechanisms, that pass actual, realized utility expenses directly to customers in the interim periods between general rate cases.

[43] *See* Consumer Advocate's Brief #3 at 43 (recommending that the ESM should be "calculated on a basis that fully includes all of the utilities' recorded PIM incentives and penalties, as well as the recorded costs incurred to achieve or avoid such incentives and penalties"); Blue Planet's Brief #3 at 17 (discussing the advantages and disadvantages of ESMs); Ulupono's Brief #3 at 3 (recommending a "symmetrical ESM" that incorporates a "flexible collar" "based on combined revenues from all performance incentive mechanisms).

[44] *See* HECO Companies' Brief #3 at 53 (discussing the relationship between extending the period between rate cases, ESMs, and ECMs), Exhibit 1 prepared by Pacific Economics Group Research LLC at 24, 28, 29,46, 85, and Exhibit 2 prepared by The Brattle Group at 25-31.

*Continuation of Fuel and Purchased Power Mechanisms*

Consistent with recommendations from the Parties, the Staff Framework includes the continued use of cost recovery mechanisms for fuel and purchased energy and capacity costs.[45] These cost trackers are essential elements of a regulatory framework that does not provide for frequent general rate cases, which would otherwise provide opportunity to revise energy production cost recovery rates.[46]

Staff recommends continuation of the risk sharing and incentive provisions in the recently adopted ECRC tariffs. Amendments to these provisions and the magnitude of risk sharing fractions should be further examined in Phase 2.[47]

*Major Project Interim Recovery ("MPIR")*

The Staff Framework includes continuation of the MPIR mechanism, recognizing the need to provide timely cost recovery for necessary, specifically approved major project investments. These "lumpy" investments cannot feasibly be addressed by an externally-indexed ARM formula designed to determine changes in total revenues over many years of an MRP control period. Nor can large project capital expenditures be feasibly predicted for extended future periods.

The MPIR mechanism may require refinements or modifications. Firmer guidelines may need to be established to ensure the MPIR mechanism is properly utilized and does not inappropriately undermine the cost control incentives provided by the MRP/ARM revenue cap regime.

Staff shares the Consumer Advocate's concern that the MPIR may incent the utilities to seek recovery for more projects, programs, and costs, which will increase the need for additional rigorous evaluation and consideration of each application and business case.[48] Concerns here can be managed, in part, through a greater focus and emphasis on power system planning and competitive all-source procurement. The nexus between the Staff Framework and the HECO Companies' proposed IGP process is described in Appendix D.

Staff also notes that shared savings and other project-specific performance incentive approaches may be viable for application to major projects eligible for MPIR recovery. Project-specific performance metrics may help ensure customers receive expected benefits.[49]

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[45]*See* Consumer Advocate's Brief #3 at 20-21; Blue Planet's Brief #3 at 12; Ulupono's Brief #3 at 22.

[46]*See* Consumer Advocate's Brief #3 at 30-31.

[47]*See* Blue Planet's Brief #3 at 12, 16; Ulupono's Brief #3 at 22-25 (recommending elimination of adjustments based on fuel cost changes for the ECRC); City and County of Honolulu's Brief #3 at 9 (recommending modifications to ECAC/ECRC/PPAC).

[48]Consumer Advocate Brief #3 at 24.

[49]*See* Blue Planet's Brief #3 at 16-17.

Staff recognizes that the MPIR provisions, as well as other mechanisms that provide for exceptional circumstances (e.g., Z-factor), present crucial but difficult challenges in an MPR/ARM framework. Staff expects further examination of these provisions in Phase 2.

**Off-Ramp Provisions**

In Phase 2, the need for appropriate provisions to provide relief or adjustments to the specific provisions of PBR elements will be considered. Considerations will include the need to identify what circumstances, if any, would justify early implementation of a general rate case, changes to protocols or specified parameters in rate adjustment mechanisms or PIMs, or amendments or termination of specific PBR mechanisms.[50]

### 4.2.3 Performance Mechanisms

*Overview*

The Staff Framework outlines a portfolio of performance mechanisms intended to provide more targeted incentives in support of particular outcomes that may not be sufficiently addressed by revenue adjustment mechanisms alone.

More specifically, staff recommends that Phase 2 examine the design and development of new **Reported Metrics** focused on *Affordability*, *Customer Equity*, *Electrification of Transportation*, *Capital Formation*, and *Resilience*; new **Scorecards** focused on *Interconnection Experience*, *Customer Engagement*, *Cost Control*, and *GHG Reduction*; and new **PIMs** focused on *Interconnection Experience*, *Customer Engagement*, and *DER Asset Effectiveness*. Existing "backstop" PIMs for *Reliability* would remain in place.

The sections that follow: (i) provide an overview of Reported Metrics, Scorecards, and PIMs; (ii) recommend specific priority outcomes to be addressed by each; (iii) highlight particular metrics that may deserve further focus; and (iv) offer design criteria to guide Phase 2 work.

**Reported Metrics, Scorecards, and PIMs**

In the goals-outcomes-metrics hierarchy established in this proceeding, a *metric* (the lowest level of the hierarchy), simply defined, is a standard of measurement. In assessing utility and market performance, metrics are central to determine how well a utility is achieving the outcomes of interest and meeting the broader goals set by regulators and policymakers.[51]

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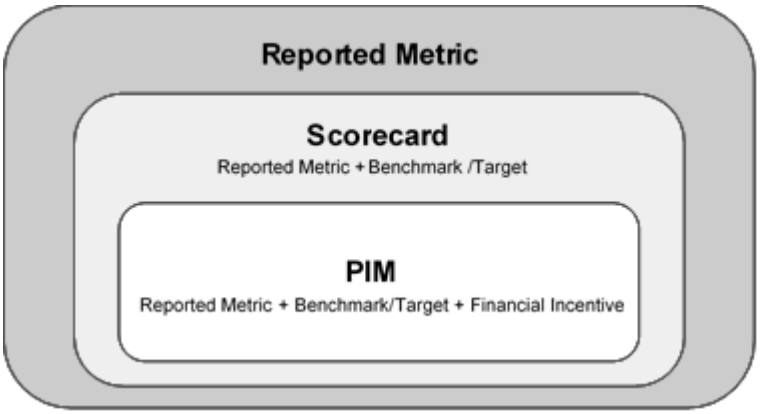
[50] *See* Consumer Advocate's Brief #3 at 21 (recommending a "scheduled MYRP review proceeding, no less than five years after commencement"), 55 (discussing importance of monitoring and modifying metrics, PIMs, and targets over time); HECO Companies' Brief #3 at 18, (referencing the Consumer Advocate's suggestion for safety nets and/or off-ramp provisions for PIMs to avoid unintended consequences), 47 (discussing off-ramp mechanisms that could be triggered by "pre-specified outcomes such as persistently extreme ROEs"); Blue Planet's Brief #3 at 20 (discussing consideration for how to proceed after the end of a "revenue control period"). Blue Planet recommends that the Commission review the "revenue cap regime one year before it expires."

[51] Whited, M., Woolf, T., Napoleon, A. *Utility Performance Incentive Mechanisms: A Handbook for Regulators*, Synapse Energy Economics, March 2015, ("Synapse Report") at 19.

As stated in Staff Report #3, metrics can be used in several ways that help track progress against outcomes and encourage exemplary utility performance. The three primary applications for metrics are: Reported Metrics, Scorecards, and PIMs.

**Figure 6. Applications of Metrics**




Reported Metric (Level 1)

At a minimum, a metric can serve as a helpful **reporting requirement**, meaning that the data reflected by the unit of measurement is tracked and published to illuminate progress towards a prioritized outcome and, in turn, toward the attendant regulatory goal. For example, the HECO Companies currently report a number of performance metrics on their website, including cost components of customer rates and demand response metrics, among many others.

Metrics can be designed as activity-, program-, and outcome-based.[52] Different types of metrics may be appropriate for a specific indicator or measurement, and a mix or blended portfolio of metric types may be warranted in the Hawaii context. Staff reiterates its previous assessment that "outcome-based metrics can be appropriate where programmatic inputs are not simple to isolate, and where the desired outcome is best pursued by a holistic approach and a range of activities that jointly influence the outcome (as well as the activities of customers and third parties)."[53] However, "program-based metrics can be helpful during transitional phases of market development and while less-established outcome-based metrics are explored. Activity-based metrics may also be appropriate in limited circumstances, such as for tracking progress on system planning or data sharing."[54]

The simple act of tracking and reporting metrics can incent utilities toward stronger performance by using transparency as a regulatory tool. Reporting standalone metrics can also be useful to

[52]*See* Staff Report #3 at 18-20 (discussing these types of metrics in detail).

[53]Staff Report #3 at 19.

[54]Staff Report #3 at 20.

inform ongoing market evaluation and policy assessments, and serve as the foundation for developing Scorecards or PIMs—the other applications detailed below.

Finally, Reported Metrics may help to inform the development of revenue adjustment mechanisms as well as to track the efficacy of all regulatory mechanisms over time.[55]

Scorecards (Level 2): Reported Metric + Benchmark/Target

Drawing from Staff Report #3, but intending to provide additional clarity, staff conceives of a Scorecard as a Reported Metric paired with either a target or a benchmark.[56] For the purpose of providing clarification on Scorecards, staff defines these terms as follows:

*Target*: A target is the desired or expected level of performance (i.e., performance expectation), essentially providing the utility with regulatory guidance on how the utility should perform. By pairing a Reported Metric with a target, one may track, and (ideally) easily understand how performance compares to the target.

*Benchmark*:[57] A benchmark is a standard by which to assess utility performance and may include utilization of historic trends or comparison to the performance of other utilities (i.e., peer comparison).[58] A benchmark may be used to inform or determine an appropriate target.

By adding a target or appropriate benchmark to a Reported Metric, Scorecards can encourage better achievement of regulatory outcomes than through Reported Metrics alone. Moreover, for areas of focus that are innovative in nature or where the data to be measured is uncertain, a performance target can be utilized to collect data and gain comfort with the underlying metric before attaching a financial incentive or penalty in developing a PIM.[59]

PIM (Level 3): Reported Metric + Benchmark/Target + Financial Incentives/Penalties

A **performance incentive mechanism** (PIM) is a metric paired with a performance benchmark/target and a financial incentive. PIMs provide financial motivation for utilities to improve performance toward established outcomes, or to discourage underperformance. Through the use of a financial award or penalty, a PIM can more strongly promote achievement

[55]Staff Report #3 at 14-15. *See* Hawaiian Electric Companies, "Key Performance Metrics," *available at* https://www.hawaiianelectric.com/about-us/key-performance-metrics.

[56]Staff appreciates the Consumer Advocate's discussion of terminology, and expects such discussions to continue into Phase 2. *See* Consumer Advocate's Brief #3 at 49-52. While staff recognizes that it draws heavily from Synapse's "Utility Performance Mechanisms: A Handbook for Regulators" (*see, e.g.*, Staff Report #3 at 13, 16), staff's characterization of performance incentives and definitions of certain terms differ somewhat from the Handbook.

[57]Staff acknowledges that "benchmark" was not explicitly defined in Staff Report #3.

[58]Staff agrees with the Consumer Advocate that a peer comparison is a type of benchmark. *See* Consumer Advocate's Brief #3 at 51.

[59]Staff Report #3 at 15.

of a prioritized outcome than a performance target or reported metric. Examples of existing PIMs in Hawaii include service quality PIMs (SAIDI, SAIFI, and Call Center Performance). Targets established for PIMs may be tied to state energy goals or other established regulatory priorities, and should balance the costs of achieving the target with the potential benefits to ratepayers.

*Staff Recommendation*
Staff recommends a portfolio approach to Reported Metrics, Scorecards, and PIMs. Such a portfolio of metric applications would likely include several Reported Metrics, Scorecards, and a more narrow, focused set of PIMs.

For PIMs specifically, staff anticipates that some may be upside only (i.e., only have financial rewards), downside only (i.e., only have financial penalties), or be both upside and downside. Regarding the scope or magnitude of the potential impact of PIMs on the utilities, **staff recommends that the Commission consider establishing between three and six PIMs that, in total, would provide the HECO Companies with incentives that would increase or decrease earnings by 150-200 basis points.**[60] This magnitude of potential utility revenues tied to achievement of priority outcomes reflects a sufficient fraction of the utility's income in order to motivate meaningful improvements in performance. Such a cap on the financial incentives of the PIM portfolio could serve to help manage concerns about potential rate impacts to customers and excessive earnings impacts for utilities. Any established PIMs would be in addition to other regulatory changes discussed in other sections herein.[61]

Staff suggests exploring PIMs for four priority outcomes: *Reliability*, *Interconnection Experience, Customer Engagement*, and *DER Asset Effectiveness*. Hawaii already has two backstop PIMs in place for *Reliability* and these should remain with possible amendments or additions. As for the other three outcomes, staff recommends the development of additional PIMs. Parties also support these outcomes as appropriate for PIM development. For example, Ulupono supports developing a PIM focused on *Interconnection Experience* for both utility-scale and distributed energy resources.[62] Several Parties support *Customer Engagement* PIMs, including metrics focused on time-of-use ("TOU") rates and community-based renewable energy ("CBRE") program participation.[63] Parties also propose a number of prospective PIMs related to *DER Asset Effectiveness,* including PIMs for demand response and other DER integration and utilization.[64]

Throughout Phase 2, staff anticipates working with Parties to determine: (1) which additional reported metrics may be appropriate, and if any currently reported metrics can be improved upon or no longer need to be reported; (2) which metrics should be paired with

[60] *See* Ulupono Brief #3 at 24; Blue Planet Brief # 3 at 28-29.

[61] HECO Brief #3 at 69.

[62] *See* Ulupono Brief #3 at 31.

[63] *See* HECO Brief #3 at 8, 29; Consumer Advocate Brief #3 at 67.

[64] *See, e.g.*, City and County of Honolulu Brief #3 at 6.

benchmarks/targets and thus established as Scorecards; and (3) which metrics plus benchmarks/targets should be paired with financial incentives and thus established as PIMs. A stakeholder working group may be well-suited to accomplish the first step of assessing and identifying current and potential metrics.

**Prospective Metrics for Further Focus**

In Table 4 below, staff provides its recommendation for how each outcome best aligned with Performance Mechanisms should be addressed: through a Reported Metric, Scorecard, and/or PIM. Further, for each outcome, staff suggests prospective metrics for further examination in Phase 2 of this proceeding. Many of the metrics included in the table were proposed in Party briefs. For a more complete summary of Parties' proposed metrics, see Appendix B.

Staff stresses that the metrics highlighted in Table 4 are provided to help inform the work to be completed in Phase 2. It is expected that only a subset of metrics will be elevated to "Level 3" and established as PIMs. Where the metrics below lack specificity, it is expected that such details will be clarified and established in Phase 2, aided by further stakeholder input.

**Table 4. Performance Mechanisms and Prospective Metrics**

| Outcome | Performance Mechanism | Prospective Metrics for Further Focus |
|---|---|---|
| Affordability | Reported Metric | -Average annual bill, by class<br>-Average annual bill as % of income, by class<br>-Number of disconnections, by month and class |
| Reliability | PIM | *-SAIDI; SAIFI; CAIDI; MAIFI; Call Center response time (existing)* |
| Interconnection Experience | Scorecard PIM | -Time to interconnect to network, by DER and IPP<br>-Cost to interconnect to network, by DER and IPP<br>-Results of developer satisfaction survey, by DER and IPP<br>-Public-facing DER interconnection dashboard |
| Customer Engagement | Scorecard PIM | -DR: % participation, by class<br>-PV: % customer adoption, by class<br>-CBRE: % participation, by class<br>-Storage: % participation, by class<br>-TOU: % participation, by class<br>-TOU: % of all customers participating<br>-Customer access to hourly or sub-hourly data<br>-Third-party service access to customer data<br>-Variety, quality, accessibility of customer data available |

| Outcome | Performance Mechanism | Prospective Metrics for Further Focus |
|---|---|---|
| Cost Control | Scorecard | -Total energy costs per customer and per MWh<br>-Total capacity costs per customer and per MW<br>-Generation assets per customer and per MW<br>-Transmission assets per customer, per mile and per MWh<br>-Distribution assets per customer, per mile, and per MWh<br>-O&M cost per customer and per MWh<br>-Customer service cost per customer and per MWh<br>-A&G cost per customer and per MWh |
| DER Asset Effectiveness | PIM | -DR: Annual max MW reduction as % of load, by class<br>-DR: MW enrolled as % load, by class<br>-PV: MWh generated as % of sales, by class<br>-PV: MW installed as % load, by class<br>-Storage: MWh installed energy capacity as % sales, by class<br>-Storage: MW installed capacity as % load, by class<br>-NWS: MW as % of (peak) load<br>-NWS: % customers participating<br>-NWS: savings per year<br>-% grid supporting services provided by DER vs. traditional |

| Outcome | Performance Mechanism | Prospective Metrics for Further Focus |
|---|---|---|
| Customer Equity | Reported Metric | -Average annual bill as % of income by LMI<br>-CBRE: number and % of LMI Subscribers<br>-% LMI customers participating in DR, PV, Storage, or TOU |
| GHG Reduction | Scorecard | -Carbon Intensity: CO2e/MWh; CO2e/MW; CO2e/customer<br>-Carbon intensity: sector-wide CO2e<br>-System-wide fossil fuel generation (MWh per fuel type) |
| Electrification of Transportation | Reported Metric | -Number of EVs added per year<br>-% of EVs in DR programs<br>-% of EVs on TOU rates<br>-Number of charging stations, by type |
| Capital Formation | Reported Metric | *-Ratemaking return on common equity (existing)*<br>*-Utility credit ratings (existing)*<br>*-Utility earnings per share (existing)*<br>-Building permit value of DER deployed by island<br>-Value of IPP contracts by island<br>-Value of DR service contracts by island |
| Resilience | Reported Metric | -SAIDI, SAIFI, CAIDI response time on black sky days[65]<br>-MW of fast ramping resources<br>-Microgrids: MW as % load, by class<br>-Microgrids: % customers served, by class<br>-Microgrids: % of critical customers served |

[65]This metric is intended to focus on network restoration to major outage events. The term "black sky days" refers to "extraordinary and hazardous catastrophes utterly unlike the blue sky days during which utilities typically operate." Dr. Paul Stockton, "Resilience for Black Sky Days: Supplementing Reliability Metrics for Extraordinary and Hazardous Events," NARUC, February 2014, *available at* https://pubs.naruc.org/pub.cfm?id=536F42EE-2354-D714-518F-EC79033665CD.

**Design Principles to Guide Phase 2 Efforts**

To be most effective, metrics must be carefully designed, keeping in mind several key principles. To support further discussion with parties and possible adoption in the proceeding, staff recommends a set of **five principles for metric design**. [66]

Metrics should:

1. Reflect desired outcomes
2. Be clearly defined
3. Be quantifiable through reasonably available data
4. Be easily interpreted
5. Be easily verified

Staff also recommends the following **PIM-specific design considerations** to guide the development and design of PIMs during Phase 2.[67]

- Set a quantitative standard for performance. The benchmarks/targets, and especially any associated financial incentives, should focus on promoting the achievement of only superior performance or penalizing poor performance.

- Benefit-cost analyses should inform the development of PIMs. PIMs should be designed to reflect some sharing of net benefits. This assessment of net benefits sets an upper limit on the value of the PIM, with further discussion about the appropriate sharing percentages between ratepayers and utility shareholders.

- PIMs should shift an appropriate amount of performance risk to the utility, in exchange for longer-term regulatory certainty and perhaps incentive compensation. Entrepreneurialism on the part of the utility should be rewarded, but PIMs should also ensure the risk and reward is comparable to that of firms in a free and competitive market.

- "Double recovery" of PIMs that achieve the same or similar outcome should be minimized (for example, a program-based DR PIM and an outcome-based PIM for improved system load factor or peak demand reduction). Care will need to be taken to ensure that the design of PIMs is coordinated so that multiple utility activities are not double-counting the same benefits and receiving reward for the same outcome(s).[68]

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[66]Adapted from Synapse's "Utility Performance Mechanisms: A Handbook for Regulators." *See* Staff Report #3 at 16-18.

[67]Staff notes that several Parties offered additional PIM-specific design principles that should be carried forward into Phase 2. *See, e.g.*, Consumer Advocate Brief #3 at 62-63.

[68]Blue Planet's Brief #3 recommends use of a framework for structuring and calibrating PIMs, which includes information on how PIMs should be coordinated and weighted relative to each other. *See* Blue Planet Brief #3 at 28-32.

- Consider designing individual PIMs so that "outstanding" performance on an individual PIM may be rewarded by additional earnings, while maintaining overall earnings caps for all PIMs.

- Consider the appropriate time frame for PIMs. PIMs can be designed to span multiple years to allow time for utility actions to take effect.

Lastly, staff recommends that the **presentation and communication** of Reported Metrics, Scorecards, and PIMs should be based on the following principles:

- Use of clear visuals so interested persons can easily understand performance. For Scorecards and PIMs, it should be easy to understand how utility performance compares to benchmarks/targets.

- Utility performance information should be presented in a central location, and presented in a transparent manner and, if applicable, in a meaningfully contextualized manner (i.e., for Scorecards and PIMs).

- Regulators as well as other stakeholders should be able to quickly review and digest utility performance across a number of Reported Metrics, Scorecards, and PIMs.

- The data should be readily accessible and featured prominently on the utility, Commission, or other website.

- The information provided should be clear, concise, comprehensive, and up to date.

### 4.2.4 Other Regulatory Mechanisms

In addition to revenue mechanisms and performance mechanisms, there is opportunity for Hawaii's PBR framework to incorporate other regulatory mechanisms. This section highlights three areas where other regulatory approaches deserve further exploration in Phase 2: (i) capex/opex equalization; (ii) innovation; and (iii) platform service revenues.

#### *Capex/Opex Equalization*

*Overview*

Traditional utility regulation creates an inherent bias for utilities to prefer utility-owned capital investments over other solutions because utilities earn a rate of return on capital expenditures (capex) but not operational expenditures (opex). Throughout Phase 1, Parties' briefs[69] and workshop activities highlighted utility capex bias as a key concern to address in this proceeding. Mitigating the utility capex bias should help drive achievement of multiple prioritized outcomes,

[69] *See* Consumer Advocate Brief #3 at 19, 24-29, 54, 69; HECO Companies Brief #3 at 11, 45-70; Blue Planet Brief # 3 at 7; DER Intervenors Brief # 2 at 3, 5, 7, 9; Ulupono Brief #2 at 17-22; County of Hawaii Brief #2 at 8, 35, 46.

including *Grid Investment Efficiency* and *Cost Control* most directly, with indirect impacts on *DER Asset Effectiveness*, *Affordability*, and *GHG Reduction*. In order to address these outcomes, well-crafted incentives can facilitate utilities' pursuit of optimal solutions, whether those are conventional investments, third-party owned assets, or more service-based solutions.

In addition to using revenue mechanisms to realign utilities' financial incentives, utilities should also pursue new approaches to resource planning, as well as the procurement processes used to identify and evaluate options.

In service to the prioritized outcomes proposed for this proceeding, staff considers several approaches to reducing the capex/opex bias:

- Shared savings mechanisms
- All-resource procurement mechanisms
- Rate basing or earning a return on service-based solutions
- Capitalization of a prepaid contract
- Totex accounting

### Shared Savings Mechanisms

Shared savings mechanisms reward a utility for reducing expenditures from a baseline or projection by allowing it to retain a portion of savings as profit while returning the remainder to ratepayers.[70] Allowing the utility to retain some level of savings provides an incentive for utilities to seek more cost-effective solutions without compromising shareholder interests. Customers also directly benefit, as savings can translate to reduced rates.

Shared saving mechanisms can apply to all expenditures (i.e., a totex approach), capital or operational expenditures only, or some subset of expenditures such as non-wires solutions or demand management programs. A comprehensive shared savings mechanism for reduced spending on the utility's entire portfolio of capital and operational expenses does not exist today in the U.S.; however, shared savings mechanisms are often the basis for targeted programs such as energy efficiency. According to ACEEE, thirteen states use this approach to incent utility energy efficiency performance.[71] Shared savings approaches are also being pioneered for NWS;

[70]Dan Aas and Michael O'Boyle, *You Get What You Pay For: Moving Toward Value in Utility Compensation, Part 2–Regulatory Alternatives*, Energy Innovation/America's Power Plan, 2016, *available at* https://americaspowerplan.com/wp-content/uploads/2016/08/2016_Aas-OBoyle_Reg-Alternatives.pdf.

[71]Seth Nowak, et al., *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency*, American Council for an Energy-Efficient Economy (ACEEE), 2015, *available at* http://aceee.org/sites/default/files/publications/researchreports/u1504.pdf.

both New York and Rhode Island have programs set up to share the savings resulting from NWS projects.[72]

The design of shared savings mechanisms depends on the type of expenditures covered and how much risk is associated with investment. Regardless of the specifics, however, all shared savings mechanisms should have a clear and transparent methodology to develop baselines and projections to mitigate the risk of inflating costs of alternatives against which savings are measured. There should also be a clear process for evaluating savings to prevent *ex post* debates over savings measurements. Another important consideration is whether or not shared savings incentives should be "symmetrical," such that risks of cost overruns are also borne by utility shareholders.

The Commission has approved a shared savings incentive for applicable renewable energy PPAs submitted in the HECO Companies' competitive bidding process in 2018 and 2019. The Commission initially established an 80% customer/20% utility split of savings from each PPA compared to benchmarks established by the Commission based on recent low-cost renewable energy projects, up to a cap of $3,500,000. The Commission subsequently extended and expanded the incentive to cover additional renewable PPAs based on an 85% customer/15% utility split of the savings, with the percentage of the utility's share of the savings dropping to 10% for any PPAs submitted in February 2019, and to 5% for any PPAs submitted in March 2019.[73]

### All-Resource Procurement Mechanisms

All-resource procurement mechanisms can provide technology- and ownership-neutral approaches to procurement that allow utilities to use the most cost-effective combination of supply- and demand-side resources to meet power supply and grid infrastructure needs. Effective all-resource procurements rely on competitive solicitations (i.e., open to non-utility solution providers) and—where appropriate—defining grid needs in terms of service requirements rather than predetermined technologies. For example, a procurement process can consider whether a PPA contract for utility-scale solar or a utility-owned project is more cost-effective. Competitive, all-resource solicitations can also produce a more diverse set of possible

[72]In 2017, the New York Public Service Commission adopted an incentive for Con Edison (ConEd) to pursue cost-effective NWS to traditional infrastructure projects. The incentive is a function of net benefits of the NWS, which includes not only cost savings but also societal benefits such as greenhouse gas reduction. ConEd receives 30% of net benefits, with the other 70% going to customers. Additionally, ConEd shares the risk of cost savings and overruns 50/50. The shared savings incentive is capped at 50% of total net benefits and can be wiped out completely by cost overruns. In Rhode Island, National Grid proposed a System Reliability Procurement incentive mechanism consisting of action-based and savings-based incentives in its 2018 SRP Report. The savings-based incentives split the net benefits associated with NWS projects, with 80% going to customers and 20% going to National Grid.

[73]Hawaii PUC, "Order No. 35564. Approving the Hawaiian Electric Companies' Proposed Additional performance Incentive Mechanism," September 6, 2018. https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A18I07A94133A00260. p.5

solutions to meet grid needs, thus encouraging greater innovation and value creation in solutions development.

Procurement can occur in the form of competitive requests for offers (RFOs), requests for information (RFIs), and requests for proposals (RFPs), all of which can be designed to solicit both capital and non-capital bids from third parties for grid resources and services. For grid needs where NWS or other service-related options may be considered, a technology-neutral evaluation process is key to ensure consideration of all competitive options. In an RFP, the utility typically issues public information including data about the need, descriptions of the solutions, instructions for response, timelines, and criteria for evaluation. Based on this information, solutions providers can develop bids. In the evaluation stage of an RFP process, solutions may be compared according to a number of qualitative and quantitative factors, such as environmental benefits, price, and hours of availability.

Another procurement option is to hold an auction, particularly when the primary goal is to find the least-cost solution for a specified need. Auctions can offer helpful transparency and price discovery, as a result of the structured and transparent mechanism employed, and the potential to attract large numbers of bids. However, a successful auction requires a fairly mature market and more narrow product definitions (e.g., MWh and MW), with a pool of prequalified bidders. While auctions are efficient, they tend to value different types of resources on the basis of price alone and may not allow for comparing diverse attributes of different resources.

Utilities in California, New York, Vermont, New Hampshire, and elsewhere are all exploring new procurement models for non-wire solutions. In California, Pacific Gas & Electric designed a joint RFO with East Bay Community Energy for specific transmission reliability needs in Oakland. This RFO was designed to solicit solutions for distributed clean energy resource portfolios as an alternate to traditional fossil-fuel-fired generation. This marks the first time that clean energy resources are being proactively deployed as an alternate to fossil fuel generation for transmission reliability in PG&E territory. PG&E is currently evaluating the responses to their RFO.[74]

For its Brooklyn Queens Demand Management (BQDM) program, New York's Con Edison used both an auction and RFP process, as well as programs, to procure 52 MW of peak load reduction. Con Edison procured 22 MW through a reverse auction. The auction started with a price ceiling, and solution providers decreased their bids until the desired MW of load reduction was met; all bidders were then compensated at the clearing price. There were 10 winners in total, including demand response and behind-the-meter battery storage providers. In this example, the clearing price Con Edison ultimately paid to companies ended up being higher than what Con Edison pays for other commercial demand response resources; however, three-quarters of the 22 megawatts

[74]"2018 Oakland Clean Energy Initiative RFO." https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2018-oakland-clean-energy-initiative-rfo.page?WT.mc_id=Vanity_rfo-ocei&ctx=large-business.

of committed load will be offered during the evening timeframe when need is greater and prices are higher.[75]

In Hawaii, the Integrated Grid Planning (IGP) process is intended to lead to increased use of all-resource procurement processes, and could better support capex/opex equalization. HECO's March 2018 IGP report highlights "identification of least-cost best-fit solution options to fulfill grid needs through the establishment of a marketplace through procurements, pricing, and programs." [76] Further, the proposed IGP process "incorporate[es] market-based solutions into the heart of the planning process to develop more optimal outcomes for customers, rather than including market engagement as the last step in a long chain of serial activities based on assumptions and modeling estimates."[77] This integrated approach is designed to solicit overall best-fit solutions for resource, transmission, and distribution needs. The resource solution sourcing component will employ an RFI process. The information from this process will then be used to identify the T&D solution sourcing needs. These T&D solutions will also be competitively sourced through an RFP, allowing non-wires solutions and other DER programs to be considered as options to meet T&D needs. The plan outlined in HECO's IGP report represents significant progress towards integrated all-resource planning.

While competitive procurement processes can help to ensure that a more complete set of options is considered, these processes alone do not overcome the structural utility incentive towards capital expenditures. That is, utilities still earn a rate of return on capital expenditures but not operational expenditures, and are therefore financially incented to choose capital expenditures where possible. Complementary financial incentives such as shared savings mechanisms may be required to ensure third-party generation or services are duly considered.

### Return on Service-based Solutions

Earning a rate of return on service-based solutions allows utilities to earn a return on payments for service-based solutions such as grid services from DER, similar to returns on a capital investment. For example, a DER incentive adder allows utilities to earn a return on the total cost of utility payments to a third party for a DER-derived service solution.[78] With an adder, the rate of return may or may not be commensurate with the rate of return for capital expenditures, but

[75]Katherine Tweed, "Con Edison Unveils Auction Numbers for Its Pioneering Demand Management Program in New York," Greentech Media, August 5, 2016, *available at* https://www.greentechmedia.com/articles/read/the-numbers-are-in-for-con-edisons-demand-management-program#gs.m7vZBidO.

[76]*In re Pub. Util. Comm'n*, *Instituting a Proceeding to Investigate Integrated Grid Planning*, Docket No. 2018-0165, "Planning Hawaii's Grid for Future Generations: Integrated Grid Planning Report," filed July 13, 2018, ("IGP Report") at 2.

[77]IGP Report at 11.

[78]Advanced Energy Economy Institute, *Utility Earnings in a Service-Based World: Optimizing Incentives for Capital- and Service-Based Solutions*, 2018. ("AEE, Utility Earnings in a Service-Based World")

is intended to provide some return on expenses that would traditionally be recovered as expenses without associated earnings. If these expenses are made more equivalent to capex by providing earnings at a rate intended to approximate the return on capital investment, this approach could also be referred to as "ratebasing" service-based solutions.

In California, the Competitive Solicitation Framework Pilot allowed an incentive equal to 4% for annual DER payments that displace or defer capital expenditure on traditional distribution project investments.[79] While there are differing perspectives on what the right size of a DER incentive should be, the incentive needs to be large enough to ensure non-capital solutions receive sufficient consideration. In addition, allowing a rate of return on certain projects and solutions requires regulatory oversight to determine which are appropriate for such an incentive and which are not. Mechanisms should also address any unintended incentives to increase expenditures for service costs to increase any resulting incentives.

### Capitalization of a Prepaid Contract

Another option is the capitalization of a prepaid contract, which treats an expense (such as payments for a service) like a capital investment by placing it into the rate base, amortizing it, and recovering costs over time.[80] For example, a service payment would be pre-paid for a number of years and would be amortized over the length of the contract. The utility would collect its annual carrying costs, including repayment for the utility expenditure and return on unamortized balances. With this option, the utility earns a rate of return on the prepaid contract in a similar manner and at a similar level as traditional rate-based assets. This approach may be easier than more innovative approaches, such as totex accounting, since it utilizes an existing regulatory approach for which there are well established accounting standards.

While this approach mitigates the utility's bias toward capital solutions, the utility may need additional incentives to choose the most efficient approach, especially if the capital expenditure option provides an opportunity to place a larger asset in the rate base. The contract length is another factor that will influence utility decision-making; longer-lived contracts will allow the utility the opportunity to earn more for the same level of initial investment. Not all service-based solutions may be treatable as prepaid contracts, limiting the applicability of this solution.

### Totex Accounting

Another approach to reducing the capital bias is determining utility revenues on the basis of total expenditure, or "totex", accounting, where a utility's capex and opex are combined into a single regulatory asset. The utility is allowed a rate of return on a portion of this combined asset, based on a predetermined percentage split as proposed in utility planning. A proportion of total expenditure is capitalized into the rate base ("slow money"), with the rest recovered on an

[79]California Public Utilities Commission, "Integrated Distributed Energy Resources," a*vailable at* http://www.cpuc.ca.gov/General.aspx?id=10710.

[80]Advanced Energy Economy Institute, "Utility Earnings in a Service-Oriented World: Optimizing Incentives for Capital- and Service-Based Solutions," January 30, 2018 ("AEE, Utility Earnings in a Service-Oriented World").

annual basis ("fast money"). At the end of the year, the utility's total actual expenditures are compared to the allowed revenue requirement. The variance in totex, whether positive or negative, is then shared between customers and the utility using a sharing factor.[81]

The RIIO (Revenue = Incentives + Innovation + Outputs) framework in the UK applies a totex approach, coupled with a shared savings mechanism and extended MRP. The first 8-year rate case under RIIO is not yet completed, but distribution and transmission operators have both been able to earn above their allowed cost of equity by outperforming their totex allowances and earning performance incentives for meeting established targets.[82]

To date, no utility in the U.S. has implemented this mechanism, in part due to concerns over accounting standards. Details over compliance with the U.S. Generally Accepted Accounting Principles (GAAP) adopted by the Securities and Exchange Commission (SEC) would need some consideration before adopting a totex approach in the U.S.

*Staff Recommendations*

In Phase 2, Commission Staff recommends the development of shared savings mechanisms and the exploration of changes to expense treatment for DER or NWS. More specifically, a shared savings mechanism for the DR Portfolio and a shared savings mechanism for NWS would appear to be near-term priorities.[83] In parallel to Phase 2 efforts, there may be opportunities to test shared savings mechanisms with existing projects and programs.

All-resource procurement is an important tool to encourage utility investments be made in a technology- and ownership-neutral manner. The HECO Companies' proposed IGP process appears to outline a promising approach that could ensure the most cost-effective combination of supply- and demand-side resources to meet grid needs. Although the IGP process will be addressed through a separate docket, it is important that IGP be harmonized and aligned with the PBR framework to emerge from this proceeding (see Appendix D).

Finally, staff recommends that Phase 2 examine changes to accounting to allow a return on service-based solutions. These solutions could include a "DER adder" (e.g., incentive to the utility that allows a revenue premium above the service expense) as well as the capitalization of a prepaid contract.

[81]AEE, Utility Earnings in a Service-Oriented World at 35-37.

[82]Advanced Energy Economy, "UK's RIIO – A Performance-Based Framework for Driving Innovation and Delivering Value," *available at* https://info.aee.net/hubfs/RIIO%20Case%20Study%20Final%20.pdf.

[83]*See* HECO Brief #3 at 27-28.

*Innovation*

*Overview*

Innovation is essential as Hawaii's electricity system and market continues to transform. Innovative products and services will be critical to not only support the functions and opportunities inherent to the evolving utility role, but also to help deliver additional value to customers. Utilities have historically been challenged to effectively innovate as a result of risk aversion and other perceived constraints. Commission staff suggests that Phase 2 include exploration of possible options to encourage utility, as well as third-party, innovative technologies, programs, and business models. Three notable approaches are currently being used in other jurisdictions to advance system and market innovation and could serve as helpful examples. These include the use of innovation stimulation funding in the U.K., an expedited pilot implementation process in Vermont, and a web-based platform to connect utilities with technology companies and other solution providers in New York.

Innovation fund

The U.K.'s RIIO framework includes an innovation stimulation package that funds research, development and demonstration of new technologies and operating and commercial arrangements at both the distribution and transmission level. The funding is a complementary component to the other performance-based mechanisms that comprise the U.K.'s regulatory model and supports areas of innovation that could deliver benefits to consumers but are at risk of not being delivered through RIIO's other incentive mechanisms (e.g., payback is too long).

While there have been different iterations of the funding mechanisms over the years, Ofgem—the regulatory body that oversees the U.K.'s distribution and transmission network operators (DNOs and TNOs)—currently operates an annual Network Innovation Competition (NIC), an annual Network Innovation Allowance (NIA), and an Innovation Roll-Out Mechanism (IRM).

For the NIC, distribution and transmission network companies submit projects for funding in partnership with other energy suppliers, universities or technology providers. About $90 million is available annually for projects through the Electricity NIC alone. These funds are collected as part of a transmission network system charge on customer bills. Network companies are also required to make a 10% non-refundable contribution to the costs of projects.[84] This contribution can come from the utility or project partners, but cannot be ratepayer money.

Two independent expert panels (one for electricity and one for gas) evaluate proposals and decide who to provide NIC funding. The panels assess each project against a set of evaluation criteria, including whether the project delivers environmental and financial benefits, generates knowledge that can be shared among all network companies, and involves other partners and external funding. To be eligible for the funding, network companies need to demonstrate that their proposed projects are new or different to avoid duplication. To ensure that the information

[84]Ofgem, "Electricity Network Innovation Competition," *available at* https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/network-innovation/electricity-network-innovation-competition.

acquired from these projects is shared with other network operators, receivers of NIC funding are required to submit annual progress reports and to present findings at events with other network companies. Examples of current NIC projects include a new method to assess the grid impact of electric vehicles and a new approach to restore the electricity system using DERs following a blackout.

Alternatively, the NIA provides an annual allowance equal to 0.5-1.0% of base revenue to all transmission and distribution network operators to fund smaller-scale and less risky technical, commercial, or operational projects that are targeted to benefit their own networks. These funds are provided on a use-it or-lose-it basis and are recovered through a distribution system charge.[85] Network licensees are required to submit annual progress reports on NIA-funded projects as well.

RIIO's third innovation funding mechanism, the IRM, is offered twice during the current 8-year price control period, with one solicitation completed in 2017 and another expected in 2019.[86] The IRM is used to fund the deployment of proven projects with environmental or carbon benefits that usually have a longer pay-back period. The IRM is intended to encourage companies to find efficiencies and cost savings compared to business as usual.

Expedited process for pilot implementation

Another option to drive innovation is to develop an expedited implementation process for pilots that test new technologies, customer engagement programs, business models, and other arrangements. Vermont has established this type of pilot process to support its clean energy and climate goals.

Vermont's renewable energy standard requires the state's electric distribution utilities to deliver "customer-facing transformative energy projects that decrease fossil-fuel consumption and greenhouse-gas emissions" and requires the state's distribution utilities to obtain "energy transformation credits (MWh)."[87] For Green Mountain Power (GMP), the state's only IOU, these credits needed to equal 2.67% of its retail sales in 2018.[88] The Vermont PUC requires GMP, and other utilities, to submit annual plans on how they will obtain these energy transformation credits. GMP's innovative pilots help the utility meet these credits.

[85]Ofgem, "Electricity Network Innovation Allowance," available at https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/electricity-network-innovation-allowance.

[86]Ofgem, "Decision on the 2017 Electricity Distribution Innovation Roll-out Mechanism," October 17, 2017, *available at* https://www.ofgem.gov.uk/system/files/docs/2017/10/final_decision_document_17_oct_2017.pdf.

[87]Vermont Department of Public Service, "Tier III – Renewable Energy Standard," *available at* https://publicservice.vermont.gov/content/tier-iii-renewable-energy-standard.

[88]These credits are calculated by converting avoided gallons of fuel resulting from GMP's eligible programs to MWh.

The Vermont PUC decided in 2014 to grant GMP approval for pursuing innovative pilots on a non-tariffed basis.[89] GMP does not need Commission approval prior to commencing these non-tariffed pilots, but is required to provide written notice to the Vermont Department of Public Service, the Commission, and Efficiency Vermont at least 15 days prior to commencing the pilot. GMP is then required to make periodic updates at six-month intervals regarding the progress of a pilot program during its 18-month term.

GMP is required to include the costs and revenues of innovative pilots and services in base rate filings for review and approval. However, the Vermont PUC does not automatically guarantee rate recovery for all innovative pilot programs. If GMP wants to offer the product or service beyond the 18-month pilot term, it must receive approval from the Commission to offer it as a tariffed service.

GMP's current pilots focus on deploying and utilizing new technologies to improve grid operations and to provide customers with new options to manage their energy use. These include:

- A pilot that provides Tesla Powerwall 2.0 batteries to residential customers for $15 a month for ten years or a $1,500 one-time fee.[90] Using Tesla's software platform, GMP can control individual and aggregated batteries to reduce system-wide peak load to produce local grid benefits.

- Another pilot enables shared access to a customer's electric resistance water heater. Customers receive a retrofit kit manufactured by Aquanta that enables them to share access to their water heaters with GMP. Through this access, GMP can turn customer water heaters on and off (with opt out capability), or adjust the temperature up or down, in response to system needs. Participating customers also receive a Nest smart thermostat as a way to increase their energy savings. [91]

Web-based innovation platform

A third option to support innovative products and services is a web-based platform that connects the utility with technology companies or other solution providers. This approach has been used in New York through a centrally managed online portal called REV Connect.[92] REV Connect's goal is to help companies and utilities deploy demonstration projects, new technologies, and diverse business models that advance New York's Reforming the Vision (REV) goals. REV Connect is

[89]Green Mountain Power, "Green Mountain Power Corporation Alternative Regulation Plan," June 2014. http://www.greenmountainpower.com/wp-content/uploads/2017/01/Alt-Reg-filed-June-4-2014.pdf.

[90]Green Mountain Power, *2018 Integrated Resource Plan*, Innovative Customer Programs, at 2.8-2.10.

[91]Green Mountain Power, *2018 Integrated Resource Plan*, Innovative Customer Programs, at 2.10-2.11.

[92]"REV Connect," *available at* https://nyrevconnect.com.

currently led and funded by New York State Energy Research and Development Authority (NYSERDA), but its operators would like to institutionalize the process at utilities.[93] The REV Connect team also includes subject matter experts from Navigant, New York Battery and Energy Storage Technology Consortium, and Modern Grid Partners.[94]

The REV Connect web-based portal connects technology companies with utilities who have specific innovation needs. The REV Connect team assesses submissions against minimum requirements and consults with qualified submitters to better understand and improve their ideas. The team then summarizes these proposals for utilities using evaluation criteria that includes: viability of business model, utility partnership structure, submitter capability, advancement of REV, and uniqueness of innovation. Utilities and well-matched submitters then work together—potentially with support from the REV Connect team—to develop a business model and partnership structure, and then to eventually gain necessary regulatory approvals. Examples of projects that have emerged from REV Connect include: new business models for DC fast charging infrastructure and new thermal solutions, deployment and utilization of controllable water heaters, and a marketplace for community distributed generation.[95]

The REV Connect program also includes "Innovation Sprints," which invite market players to submit ideas for a specific theme. The entire submission process is condensed into a 3-month timeframe to quickly transform ideas into projects. 2019 Innovation Sprints will be focused on: "clean heating and cooling," "electrifying transportation," and "innovating energy efficiency."

*Staff Recommendation*

There is an opportunity in this proceeding to develop one or more of these mechanisms to support utility and third-party innovation as a complement to other updates to Hawaii's regulatory framework.

In the nearer term, staff recommends the development of an expedited pilot implementation process, which could result in several leading-edge projects without the limitations of traditional program approval. However, there would need to be clear guidance on eligibility for cost recovery at the outset. There also needs to be consideration of how pilots could then transition into full-scale programs and services. Staff suggests Parties explore this option further in Phase 2 of this proceeding.

In addition, a web-based portal that can easily connect the Companies with technology companies and other solution providers in a streamlined and facilitated manner could produce fruitful partnerships to drive innovation in Hawaii's electricity system. However, there needs to

[93]Walton, Robert. "Project of the Year: REV Connect," *Utility Dive*, December 3, 2018. https://www.utilitydive.com/news/rev-connect-project-of-the-year/539951/.

[94]Modern Grid Partners are utility consultants focused on grid modernization issues. See http://www.moderngridpartners.com/.

[95]"REV Connect Outcomes," *available at* https://nyrevconnect.com/rev-connect-outcomes.

be a willing and capable entity to manage the online portal if not managed by the Companies. Commission staff invites input from Parties on how this platform may be developed and implemented in Hawaii.

An annual funding opportunity could potentially be successful in directly providing the Companies with a new source of capital to invest in innovative projects.[96] While it is not immediately clear where this funding could come from, staff suggests Parties explore this option further in Phase 2 of this proceeding.

#### *4.2.4.1 Platform Service Revenues*

*Overview*

A fundamental goal of moving toward a performance-based incentive structure is to better align utility service provision and utility revenues with delivery of customer and societal value. As customer adoption of DER continues apace, and as emerging technologies enable new grid solutions more broadly, a modern PBR framework should offer utility earnings opportunities that enable utilities to thrive in a changing environment, while meeting customer-oriented objectives and delivering value-added services.

Platform business models—and associated revenue streams—provide a potential approach to modernize the utility business and foster the exchange of cost-effective, third-party energy services. A *platform* is a business based on enabling value-creating interactions between external producers and consumers.[97] The platform provides an open, participative infrastructure for these interactions and sets governance conditions for them, with the overarching purpose to facilitate transactions and create value for all participants.[98] Platform businesses are prominent in other sectors of the economy, including in finance, retail, and many service sectors.[99]

A platform business model may be particularly well-suited for electric utilities because, by harnessing a multi-sided DER market, platforms can leverage spare asset capacity at the grid edge, thereby providing network services and value to the power system overall, while also supporting innovative services that deliver customer-specific value. Moreover, as the administrator and operator of the platform, the utility could generate platform service revenues from actions that are aligned with customer preferences and state policy goals. The concept of a platform utility was discussed by numerous parties in the course of Phase 1 and is consistent

[96] *See* HECO Brief #3 at 79-81.

[97] Geoffrey G. Parker, Marshall W. Van Alsytne, and Sangeet Paul Choudary, Platform Revolution: How Networked Markets are Transforming the Economy and How to Make Them Work for You, W.W. Norton & Co., 2016 ("Platform Revolution"), at 5.

[98] *See* Platform Revolution at 5.

[99] *See* Platform Revolution at 3-5.

with previous Commission guidance for the HECO companies to embrace functions associated with that of a network integrator and operator.[100]

Platform service revenues may be distinguished from other traditional and alternative revenue sources[101] by their relationship to the administration and operation of market-related DER transactions. Examples of platform service revenues related to DER transactions include, but are not limited to, fee-based transactions, lead origination for third-parties, subscription or access fees, and value-added data analysis. Other value-added services related to DER utilization could also be considered platform service revenues. These services might include the installation or optimization of microgrids.

A crucial and near-term opportunity for utility platform service revenues may be sharing customer and system data. Data sharing is identified as a near-term opportunity because the development of new products and services will be inhibited without access to and analysis of applicable data. Given that the utility has control and access to most of the pertinent data on the power system, finding equitable opportunities to incent new product creation and services may benefit all stakeholders.[102] Unleashing system data to enable third-parties to better understand customer and system needs will continue to advance DER from providing primarily passive system value to becoming integrated into short-term system operations and long-term system planning.

Building a utility platform beyond infancy will require innovation and creativity. This suggests that opportunities for platform service revenues will likely derive from a rethinking of how current services are procured and produced, such as is being developed in the HECO Companies' DR Portfolio,[103] or enabling new types of interactions between producers and consumers.

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[100]*See* Docket No. 2012-0036, Decision and Order No. 32052, filed April 28, 2014, Exhibit A (the Commission's "Inclinations"), at 13-14, 20; Docket No. 2015-0412, Decision and Order No. 35238, filed January 25, 2018, at 3-4.

[101]Platform Service Revenues can be defined as all new forms of utility revenues associated with the operation or facilitation of distribution-level markets. Other new utility revenue opportunities abound, but may not be derived from the operation of a platform model. *See* Steven Propper, "Alternate Utility Revenue Streams: Expanding Utility Business Models at the Grid Edge," GTM Research, May 2015, at 20-25. (highlighting new revenue streams for utilities such as film scouting services, landscaping and tree trimming services, wireless consulting, and lighting solutions).

[102]Data sharing and product development can trigger concerns related to competition. *See* NY PSC Case 14-M-0101, REV Track 2 Order for the criteria used to evaluate this issue in New York.

[103]*See In re Hawaiian Elec. Co., Inc., Maui Elec. Co. Ltd., and Hawaii Elec. Light Co., Inc.*, Application for Approval of Demand Response Portfolio Tariff Structure, Reporting Schedule, and Cost Recovery of Program Costs through the Demand-Side Management Surcharge, Docket No. 2015-0412, Decision and Order No. 35238, filed January 25, 2018.

Facilitating NWS may be another area where platform service revenues could be generated by the utility. The utility is in a unique position to connect with locationally-specific customers, while also having a deep understanding of individual customers' energy needs—both types of information are critical for successful implementation of NWS. Utilities could generate platform service revenues through locationally-specific buyer and seller connections, and potentially through a regulatory incentive for successful NWS.

Under any scenario, attention is needed to further develop the platform utility concept and the specific applications for platform service revenues, including how those correspond to performance-based regulations. As evidenced by this docket, Hawaii's regulatory structure cannot align complex utility incentives with public policy goals utilizing only one or two simple changes—it will take a suite of complementary mechanisms to adequately align utility incentives with that of its customers and state policy. For that reason, platform service revenues will need to be integrated into and complemented by the PBR structure that evolves from this docket.

*Staff Recommendation*

Staff believes it is appropriate to consider during Phase 2 how platform service revenues may be incorporated into the future regulatory structure and utility business model. While platform revenue streams received a lot of attention during the onset of the New York REV Initiative, the discussion has quieted in recent years. However, staff believes that Hawaii differs significantly from other states that have considered incorporating platform service revenues into the regulatory structure. One primary difference is that Hawaii is already at the stage that many states are preparing to be at in 5 to 10 years—high adoption of DER, opportunities to resolve issues on the distribution system, and ambitious, rapid renewable energy goals. In addition, Hawaii's unique regulatory structure (vertically-integrated utilities without established wholesale markets) may allow for more rapid market development and innovation. The unique conditions present in Hawaii suggest that exploring platform service revenues may result in significant benefits for all stakeholders.

# 5 NEXT STEPS

As described above in Section 2, the Commission set out a two-phase process in its Opening Order.[104] Phase 1, which began in July 2018, includes three major steps.

1. Identification of regulatory goals and outcomes to serve as guiding principles and to ground an assessment of the regulatory framework;
2. Assessment of which outcomes are currently well-served by the regulatory framework and which require greater focus and examination; and
3. Determination of which regulatory mechanisms are best-suited to achieve each prioritized regulatory outcome and identification of attendant metrics, where appropriate, to measure utility performance in achieving those outcomes.

[104]Opening Order at 5-6.

Phase 2 of this proceeding will focus on design and implementation of new or updated regulatory mechanisms to achieve the priority outcomes identified in Phase 1. In this phase, the Commission intends to "work collaboratively with stakeholders to: streamline and/or refine elements of the existing regulatory framework; develop incentive mechanisms to better address specific objectives or areas of utility performance; and explore regulatory frameworks that result in more incentive-neutral utility investment decisions between capital- and service-based solutions."[105]

## 5.1 PROCEDURAL STEPS

The Parties shall submit by March 8, 2019 their Statements of Position ("SOPs")

Parties will have the opportunity to file limited information requests regarding the Parties' Statements of Position by March 18, 2019, with responses due no later than March 25, 2019. Information requests shall not request responses from the Commission. Information requests shall not exceed ten (10) questions in number, including subparts.

Parties may submit Reply Statements of Position by April 5, 2019. Thereafter, the Commission intends to issue a decision and order to conclude Phase 1 of this proceeding.

## 5.2 GUIDANCE REGARDING PARTIES' STATEMENTS OF POSITION

Implementation of the PBR elements proposed herein depends upon determination of many crucial details that have not yet been identified and are subject to more focused and thorough examination in Phase 2. In the remaining steps of Phase 1, Parties are encouraged to present comments on and critique the Staff Framework and are free to propose and support alternative approaches, elements, and details in the Party Statements of Position and Reply Statements of Position. The Commission, by Phase 1 decision and order, expects to provide more definitive scope and focus to guide the Phase 2 design and implementation efforts.

To that end, in their Statements of Position, Parties are asked to provide constructive feedback on the Staff Proposal. Parties are encouraged to propose amendments, additions and/or alternatives to staff's recommendations, in order to provide opportunities for discovery and response by other Parties. SOPs should focus on providing well-supported guidance to the Commission in aid of formulating a Phase 1 decision and order that can provide effective scope and focus for Phase 2 of this proceeding.

Parties may consider structuring their briefs to present a proposed PBR framework to guide efforts in Phase 2. Parties may highlight areas of agreement with the Staff Framework, if any, and offer specific alternative proposals where appropriate. Parties may also consider addressing one or more of the following:

[105] Opening Order at 6.

- Do the elements in the Staff Framework sufficiently address the identified Priority Outcomes?

- Have sufficient and appropriate mechanisms been identified to effectively incent utility cost control?

- Have sufficient and appropriate mechanisms been identified to address utility biases regarding: capital versus operating expenditures; and utility investment versus contractual resource acquisition?

- What amendments, additions or alternatives to existing regulatory mechanisms or the mechanisms proposed in the Staff Framework should be further examined in Phase 2?

- What are the challenges, impacts, problems and/or shortcomings that must be addressed regarding the staff's recommendations and any proposals offered by the Parties?

- How are any alternative proposals preferable to what is proposed in the Staff Framework?

- What specific mechanisms should be implemented to provide utility customers with immediate "day-one" rate reduction benefits that reflect achievable cost savings in utility expenses?

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# *APPENDIX A*

*Description of Staff's Recommended Priority Outcomes*

## APPENDIX A

## Description of Staff's Recommended Priority Outcomes

**Affordability:** This outcome has been a longstanding priority of utility regulation and should remain an area of focus in this proceeding, particularly as Hawaii customers experience the highest electric retail rates in the nation. This outcome is very closely related to the priority outcome of Cost Control. While Cost Control is likely best addressed by revenue adjustment mechanisms and possibly other regulatory mechanisms, Affordability can be viewed as the customer-facing side of the cost reduction equation – to track and ensure that savings are resulting in lower customer bills and not accruing solely to shareholders. Accordingly, this prioritized outcome is likely best addressed through performance mechanisms, e.g., reported metrics, to track performance such as average monthly bill by rate class.

**Reliability:** Having a reliable supply of electricity is more than just a convenience. It's a necessity. Our economy – and our way of life – depend on it. For utilities, maintaining a high level of reliability requires constant commitment and is central to the core functions of providing safe, reliable, and affordable electricity for all customers. The North American Electric Reliability Council's definition of reliability encompasses two concepts: adequacy and operating reliability. Adequacy is defined as "the ability of the system to supply the aggregate electric power and energy requirements to the consumers at all times." Operating reliability is defined as "the ability of the system to withstand sudden disturbances such as electrical short circuits." The level of reliability is typically measured by the frequency, duration, and magnitude of the loss of service to total customers.

Performance mechanisms would appear to be the category well-situated to address Reliability. PIMs are already in place for SAIDI and SAIFI. Additional PIMs or scorecards may need to be considered through the course of this proceeding.

**Interconnection Experience:** As the number of DER, community-based renewable energy (CBRE) projects, and third-party-owned, grid-scale resources on Hawaii's electric grids increase, a streamlined process for connecting these technologies is needed to ensure interconnection is efficient and seamless. Numerous aspects and phases of the interconnection experience are important for customer services, grid management, and achievement of Hawaii's clean energy goals. This is an emergent outcome of the electricity system for the simple reason that the interconnection of many thousands of customer-sited DERs was not a practical consideration historically. As the power system shifts to reflect the priorities and needs of a modern energy network, including growing customer-sited DER, that evolution must include improved interconnection processes. That said, this outcome is intended to include the interconnection of grid-scale resources from third-parties, as well. There are opportunities to increase the transparency, reduce the cost, and otherwise streamline the interconnection process for independent power producers.

Interconnection Experience may be best addressed through the use of performance mechanisms. Depending upon the metrics developed for this outcome, scorecards could be developed comparing the utility's interconnection performance to that of its peers. In addition, PIMs might be appropriate to financially incent expedient interconnection for customers.

As with most (if not all) outcomes, other categories of regulatory mechanisms may have an indirect effect on the achievement of Interconnection Experience. For example, with respect to revenue adjustment mechanisms, a decoupling mechanism may mitigate a utility's throughput incentive and lessen the financial disincentive to facilitate DER interconnection and adoption.

**Customer Engagement:** Utilities need to adequately and equitably facilitate a move toward an inclusive, customer-oriented electric grid, as customers evolve from passive consumers of a commodity (kWh) to active participants in a dynamic market for grid services. Expectations for Customer Engagement have increased along with technological advances. Given increasing reliance on distributed resources, successful customer engagement will likely be a key component for Hawaii to meet its clean energy goals.

As a result, it may be important to track customer participation in DER, DR, and CBRE programs, as well as the level of quality program administration and innovative product and service offerings on the part of the utility. Although Customer Engagement poses some inherent difficulties for direct measurement, some helpful proxy measurements may be developed. Accordingly, Customer Engagement may be best addressed through performance mechanisms, driving exemplary utility performance in this area by use of scorecards or, perhaps, carefully tailored PIMs.

**Cost Control:** Cost control is a traditional regulatory outcome, and several of Hawaii's existing regulatory mechanisms are designed to ensure reasonable utility costs. As shifting grid economics and RPS goals bring new investments in the grid and non-traditional assets (such as EV infrastructure), heightened attention is needed to control costs. Cost Control should remain a continued priority as other changes to the regulatory framework are contemplated in this proceeding.

Multiple regulatory mechanisms could be assigned to this priority outcome. Possible regulatory mechanisms include Revenue Adjustment Mechanisms (such as revenue cap regulation under a MRP), Performance Mechanisms (such as reported metrics) as well as Other Regulatory Mechanisms, such as shared savings mechanisms.

**DER Asset Effectiveness:** The HECO Companies' service territories have experienced some of the highest DER adoption in the world. The trend toward more dynamic and distributed power systems is expected to continue, as a result of underlying economics, customer preferences, and the State's policy goals. As the electric utility network continues to transform from one defined by central station generation and one-way power flow to a system in which there are many thousands of DERs and multi-directional power flows, there is an emergent and increasing need to ensure that these resources play an integral role in the functions and balancing of the network.

This outcome relates to other priorities, including Affordability, Cost Control and Grid Investment Efficiency, because more effective utilization of DERs may help to defer large capital investments and increase grid reliability, at lower costs than traditional solutions.

DER Asset Effectiveness may map best to the Performance Mechanisms category, as targeted PIMs, with carefully crafted underlying metrics, could help to incent greater utilization of customer-sited assets and potential mitigate any capital bias that would cause DER solutions to be disfavored by the utility.

**Grid Investment Efficiency:** Given the high cost of electricity for Hawaii customers, and the increasing availability of alternatives to traditional electric service, it is imperative to pursue a broad set of solutions for grid needs irrespective of the nature of the investments (i.e., investment in utility-owned capital expenditures versus third-party provided service-based solutions). Focusing on efficient grid investment could provide an opportunity to correct the capital investment bias that is inherent in conventional electricity regulation. New investment approaches, both for the combinations of technologies considered, as well as the procurement processes used to identify and evaluate options, may help reorient utilities' financial incentives to encourage pursuit of different investment portfolios and more creative solutions. Under this outcome, attention will also be needed to the relative merits and comparative value of investment and asset ownership by non-utility actors, including independent power producers, third-party solution providers as well as end-use customers.

Potential mechanisms to address Grid Investment Efficiency might include other regulatory tools, such as shared savings mechanisms or, perhaps, in the longer-term, an approach that could level the playing field between utility-owned capital solutions and third-party service solutions.

**Customer Equity:** It is a public policy imperative that, to the extent possible, all customers fairly share in the costs and benefits associated with Hawaii's energy transition. If customer equity is not a priority in ongoing regulatory development, there is a risk that the direct benefits of electricity system changes will unfairly accrue to a limited portion of customers and companies. Performance Mechanisms may be suited to address this prioritized outcome, either through reported metrics or scorecards. Moreover, other regulatory tools, including, for instance, targeted energy efficiency programs or CBRE projects could help ensure that LMI customers are able to realize cost savings through customer investments and programs.

**Capital Formation:** Capital formation is the ability of the utility to attract debt and equity at a reasonable cost, in order to conduct its business, including investments in necessary new assets. Beyond the utility, capital formation also can refer to the ability of third parties and customers to invest in new energy technologies at sufficient scale. Traditionally, this outcome has been focused almost exclusively on the utility's credit rating and financial health. Going forward, this outcome could begin to consider broader capital flows in the electricity sector. The increasingly diverse and competitive marketplace for energy services suggests that regulations do not serve their societal objectives through a narrowly constructed view to only promote the financial health of the utility. Rather, while indisputably an important regulatory consideration, the

utility's financial profile should be evaluated along with other sources of market investment that can serve customer and societal needs.

At this time, it is not immediately clear how capital formation may translate into regulatory reforms. However, given its broad significance and underlying relation to activities necessary to accomplish state energy policy goals, it will be helpful to maintain Capital Formation as a priority outcome for further attention and contemplation. Including this outcome among others can, at a minimum, provide a useful reference to monitor overall conditions and place the utility in the context of broader market health.

A proposed performance mechanism considered for this regulatory outcome may seek to support capital formation at three related levels: the utility level, third-party market participants, and the consumer. An outcome such as Capital Formation, however, may be best-suited to a reported metric approach, where it can provide a useful reference to monitor overall conditions and place the utility in the context of broad market health. This could be measured in many ways; for example, through a record of total annual investment in the State's electricity sector; total non-utility investment in the electricity sector; along with the utility's credit rating.

**GHG Reduction:** Reducing the greenhouse gas (GHG) emissions of Hawaii's electricity system is a priority, as evidenced by HB 2182, recent legislation that sets a goal of carbon neutrality by 2045. Where the 100% RPS standard imposes a requirement to increase the share of renewable energy supply in the power system, the GHG Reduction outcome offers a different focus aimed more directly at reducing emissions attributable to the power system. This is especially important as increasing portions of the economy may be electrified in coming years, including transportation. Traditional utility regulation was not crafted with carbon reduction in mind but, going forward, regulations may be designed to support cost-effective decarbonization of the power system.

This prioritized outcome may be best addressed through Performance Mechanisms, such as reported metrics or scorecards to track utility performance, and potentially compare it against peer utilities. If, over time, the collected data warrants further examination and regulatory attention, a prospective scorecard could be considered for elevation to a PIM.

**Electrification of Transportation:** Electrification of Transportation (EoT) represents an area of key interest in the State, as evidenced, in 2017, by Hawaii's four counties announcing a commitment to 100% clean transportation by 2045 and the conversion of their own fleets by 2035. The HECO Companies have stated the important potential of EoT to help achieve both greater clean energy and customer benefits. EoT also constitutes an emerging business opportunity for utilities, as it presents an opportunity for increased customer engagement, as well as to offer additional value to customers. Expanding charging infrastructure further raises questions about the role of the utility as opposed to other third-party providers. EoT may fundamentally change the grid, making it even more distributed and integral with broader economic and social activities. These changes provide both an opportunity and a challenge, which should be evaluated further for the ways in which EoT can be incorporated into utility regulations.

At this stage of EoT market development and electric vehicle adoption, existing regulatory mechanisms may incent utility support of this outcome already. Accordingly, it might be sufficient to address this outcome through the use of performance mechanisms, such as a scorecard, to track customer adoption and monitor grid preparedness. Appropriately tailored metrics could monitor whether further regulatory support is needed in the future.

**Resilience:** Resilience is the ability of a system or its components to adapt to changing conditions, as well as withstand and rapidly recover from disruptions. Resilience can be thought of as having four dimensions: (1) robustness (the ability to absorb shocks and continue operating); (2) resourcefulness (the ability to skillfully manage a crisis as it unfolds); (3) rapid recovery (the ability to get services back as quickly as possible); and (4) adaptability (the ability to incorporate lessons learned from past events to improve resilience).[1]

Threats to the grid can be both external (e.g., physical and cyber-related attacks from adversaries) and internal (e.g., aging infrastructure and the increasing adoption of variable generation). In light of the risks facing the electric power system, heightened further by Hawaii's geographic isolation and exposure to natural disasters, there is an increasing need for attention to resilience.

[1] *See Resilience of the U.S. Electricity System*, at 1, *citing* National Infrastructure Advisory Council, A Framework for Establishing Critical Infrastructure Resilience Goals (Washington, D.C.: National Infrastructure Advisory Council, 2010) *available at* https://www.dhs.gov/national-infrastructure-protection-plan.

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# *APPENDIX B*

*Summary of Parties' Metrics Briefs*

## APPENDIX B

## Summary of Parties' Metrics Briefs

In their Metrics Briefs, Parties were encouraged to focus on mapping prioritized regulatory outcomes to appropriate regulatory mechanisms as well as proposing specific metrics for each outcome, where appropriate. Parties were also requested to provide insight on refinements to current regulatory mechanisms and propose other potential new mechanisms to best achieve the list of prioritized outcomes. To aid the Parties in conducting their assessments, Staff's third concept paper included a prospective approach to map outcomes to categories of regulatory mechanisms.

The following Parties submitted Regulatory Assessment Briefs: Division of Consumer Advocacy ("Consumer Advocate"); Hawaiian Electric Companies ("HECO"); County of Maui; City and County of Honolulu; County of Hawaii ("COH"); Ulupono Initiative, LLC ("Ulupono"); Life of the Land ("LOL"); Blue Planet Foundation ("Blue Planet"); Hawaii PV Coalition, Hawaii Solar Energy Association and Distributed Energy Resources Council of Hawaii ("DER Intervenors"); and Hawaii Solar Energy Association and Distributed Energy Resources Council of Hawaii ("HSEA-DERC"). The Hawaii State Energy Office of the Department of Economic Development and Tourism ("DBEDT") submitted a White Paper, "Hawaii Performance-Based Regulation Policy," as a public comment in this docket. Kyle Datta also filed a public comment.

The Parties submitted detailed and thoughtful feedback on the relationship between existing regulatory mechanisms, potential PBR outcomes, and proposals for new regulatory mechanisms during Technical Workshop #3 and through their respective briefs. From the feedback provided to date, several themes have emerged. Several Parties request clarification of the definition or intended meaning of certain outcomes including Affordability, Resilience, Reliability, Social Equity, DER Interconnection Experience, EoT, and Capital Formation.[2] Some Parties have conflicting views on the meaning and purpose of certain outcomes.

Many of the Parties propose modifications to the current regulatory framework. The CA, HECO, and Ulupono discuss the need to establish a new form of Multi-Year Rate Plan ("MRP").[3] Blue Planet proposes a "PBR Revenue Cap" that is similar to the Consumer Advocate's proposed modified MRP.[4] The Consumer Advocate, HECO, Ulupono, and Blue Planet discuss considerations for designing an ESM.[5] Certain Parties present different views on a "total expenditure" or "Totex" approach that equalizes treatment of capital expenditures, operating expenditures, and third-party services.[6] Many Parties discuss the relationship between PBR and the HECO Companies'

[2] See for example: CA at 6-14, City and County at 10, HECO at 11, 40, and 74.

[3] See CA at 17-27, 41, 48; HECO at 11-12, 46-53, 66-71; Ulupono at 39.

[4] See Blue Planet at 9-13, 20.

[5] See CA at 43, 46, 65; HECO at 63-64, Ulupono at 3; Blue Planet at 17.

[6] See City and County at 15-16, CA at 68-70, HECO at 69, and Blue Planet at 10.

IGP process.[7] Parties recommend principles for designing PIMs and metrics.[8] Parties also provide an extensive list of recommended metrics and offer suggestions for metrics to which PIMs and targets should be applied.

There is a need to continue thoughtful dialogue around details of a new MRP, appropriate modifications to regulatory mechanisms, and principles for designing PIMs and metrics to sufficiently focus efforts in Phase 2. The following summary of the Parties' Metrics Briefs is offered to help advance the conversation and assist the Parties in drafting their Phase 1 Statements of Position.

## Goals and Outcomes Feedback

The Parties generally agree with Staff's suggested framing of goals and outcomes, however certain Parties offer suggestions for how the framework established in Staff Report No. 3 should be modified.

### Affordability

The Consumer Advocate ("CA") believes that the Affordability outcome's meaning should be clarified and maintains that "affordability means protecting customers with high energy burdens, particularly low-income and other disadvantaged customers." [9] Similarly, the City and County of Honolulu suggests that the definition of the Affordability outcome could be refined and "included as a subset of the outcome of Social Equity."[10] In contrast, Blue Planet recommends that Affordability should be combined with the Cost Control outcome.[11]

### Resilience and Reliability

The Consumer Advocate does not agree that Resilience should be classified as a Societal Outcome and recommends potentially combining this outcome with Reliability and also including Cybersecurity to create the single outcome grouping, "Reliability, Resilience, and Cybersecurity."[12] In contrast, HECO believes that Resilience should be "appropriately differentiated from reliability in both the objective and metrics."[13] HECO recommends using a stakeholder process for developing dimensions for how resilience should be measured.[14]

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[7] See CA at 68; DER Intervenors at 14, City and County at 15-16.

[8] See for example: CA at 41-43, 59-52, 62-64, 68-69; HECO at 16-17; City and County of Honolulu at 11-12,15; Blue Planet at 3,28-32; and HSEA-DERC at 7,16-17.

[9] CA at 6.

[10] City and County at 10

[11] Blue Planet at 7. Blue Planet cites HECO and CA Briefs filed October 25, 2018 where the CA and HECO proposed that Affordability and Cost Control be combined into a single outcome.

[12] CA at 7.

[13] HECO at 40.

[14] HECO at 11.

## Social Equity

The CA believes that Social Equity should be reframed to Customer Equity and moved to the Customer Experience goal because "Social Equity could be construed to imply non-utility system impacts, such as environmental justice, economic opportunity, or employment impacts."[15] The CA also suggests that customer satisfaction should be included as an outcome.

## DER Interconnection Experience

The CA "cautions the Commission that selecting DER Interconnection Experience as a priority regulatory outcome might unintentionally create customer inequities" and recommends that this outcome be defined to cover interconnection experience for both DER customers and independent power producers.[16] The CA recommends that this outcome be moved to the Enhance Utility Experience Goal.

## Electrification of Transportation

The CA states that the objective of the EoT outcomes should be "to achieve the state's electrification goals at the lowest reasonable cost."[17] The CA offers following critique for the EoT outcome: "Electric utility customers should not be required to bear transportation-related costs that would be more appropriately borne by other customer sectors, by third parties, or by government agencies."[18] Blue Planet states that "it is unclear whether utility business activities in transportation electrification should be regulated or unregulated. If regulated, transportation-related investments will raise complicated questions for traditional utility accounting and cost allocation, including the concern whether the traditional utility business is subsidizing new 'competitive' utility services.[19]

## Capital Formation

Many of the Parties interpret the Capital Formation outcome to mean different things. The CA argues that there is an important distinction to make as some parties have suggested that this outcome should apply to third parties:

> "The priority should be to ensure that the utility is able to attract equity and debt at reasonable costs and recognize that the utility's financial health affects the ability for independent power producers to obtain reasonable financing. The priority should not include measures or metrics that target capital formation for customers or third parties. . . Capital formation for these non-utility parties is their own responsibility, should not be

[15] CA at 9.

[16] CA at 12-13.

[17] CA at 14.

[18] CA at 14.

[19] Blue Planet at 11.

supported through ratepayer-funded initiatives, and is not something that the utilities should be provided financial incentives for."[20]

The CA suggests moving this outcome to the Improve Utility Performance goal. The Companies "are concerned that the proposed treatment of financial integrity as a consideration to be prioritized in the outcome *Capital Formation* may make it too easy to avoid consideration of [its credit rating]."[21]

Blue Planet seeks clarification about what the term Capital Formation actually means. Blue Planet poses the following questions: "Do publicly owned utilities engage in or enable 'capital formation,' or does this outcome apply only to investor-owned utilities? Is 'capital formation' essentially another term for sector-wide 'capital spending'?"[22]

## Multi-Year Rate Plan

The CA, HECO, and Ulupono discuss the need to establish a new form of Multi-Year Rate Plan ("MRP").[23] The CA maintains that suspending the existing triennial rate case cycle "effectively break the direct link between utility capital investment and utility rates, while inducing and rewarding stronger cost control initiatives by utility management since higher costs could not be translated into more revenues."[24] The CA proposes a 5-year comprehensive review window for the MRP and PBR with an Earnings Sharing Mechanism ("ESM") to "moderate swings in actual utility earnings throughout this period."[25] The CA suggests that in extreme circumstances, the utilities could be allowed to file an application with the Commission for exceptional recovery through the RBA and that Specification of detailed definitions and provisions for exogenous factors should be taken up in Phase 2.[26]

The CA lists nine elements of its proposed MRP:

1. "Suspension of traditional rate cases for an indefinite future period.
2. A new, purely index driven RAM to set the base rate target revenue price path for business as usual operations on a basis other than actual cost of service, compensating for inflationary pressures upon the core business and accounting for productivity gains, while ensuring that the "real" price of electricity is relatively constant.

[20] CA at 13.

[21] HECO at 74

[22] Blue Planet at 6-7.

[23] See CA at 17-27, 41, 48; HECO at 11-12, 46-53, 66-71; Ulupono at 39. Blue Planet, County of Maui, City and County of Honolulu, County of Hawaii, DER Intervenors, HSEA-DERC, and LOL do not discuss MYRPs in their briefs.

[24] CA at 18.

[25] CA at 48.

[26] See CA at 41.

3. Continuation of the existing Revenue Balancing Account ("RBA") to ensure utility recovery of Commission-approved target revenues without regard to fluctuations in utility sales levels.

4. Continuation of existing surcharges for targeted recovery of large and volatile energy and purchased capacity costs through the Energy Cost Recovery Clause ("ECRC," previously Energy Cost Adjustment Clause "ECAC") and Purchased Power Adjustment Mechanism ("PPAC").

5. Continuation of existing surcharges for Commission-approved project and program costs through the Major Project Interim Recovery ("MPIR"), Public Benefit Fund ("PBF"), Renewable Energy Infrastructure Program ("REIP"), and Integrated Resource Planning / Demand Response costs ("IRP/DSM" or "DRAG").

6. A carefully defined exogenous factor that would permit single-issue base rate adjustments to address only clearly extraordinary events, such as catastrophic storm restoration costs or tax law changes exceeding a threshold dollar impact.

7. Performance Incentives targeted, as more fully described in Section C of this Brief, to reward the utility for improved performance against Commission-approved metrics and benchmarks.

8. Symmetrical earnings monitoring and sharing, applied on an annual basis to ensure financial outcomes within acceptable ranges of Return on Equity ("ROE"), implemented as one-time annual revenue charges or credits, o prospectively applied rate changes or rate case triggers.

9. A scheduled MRP review proceeding, no less than five years after commencement, to investigate performance under the plan and explore potential improvements to the regulatory framework."[27]

The CA contends that while rate case suspension would "vastly expand the regulatory lag incentive for management efficiency,"[28] it would present certain implementation challenges that would require careful analysis and deliberation within Phase 2 of this docket. These challenges include:

1. "To what extent are the existing "inception" target revenues for each utility adequate or excessive on a going-forward basis?

2. What price level and productivity indices, within the simplified RAM [], will most reasonably provide revised target revenues each year that are adequate but not excessive?

[27] CA at 20-21.

[28] CA at 21.

3. How and through what processes can existing mechanisms that are now administered within rate cases (such as pension and other post-employment benefit tracking, excess deferred tax amortizations, deferred software costs and benefits and other regulatory asset matters) be reconciled or eliminated prospectively?

4. Would book depreciation accrual rates continue to be periodically studied and revised by the Commission?

5. What venue and process should provide for needed changes to utility rate design in the absence of rate cases?

6. Should any exogenous factors or financial performance thresholds be prescribed as "triggers" for a future rate case if needed?

7. What new rules or processes should be enhanced to ensure adequate regulatory review of MPIR, REIP and other cost recovery mechanisms if rate case recovery is no longer possible?"[29]

Blue Planet and the City and County of Honolulu recommend that PBR outcomes should also apply to the MPIR. The City and County of Honolulu suggests that the MPIR should be updated to require demonstrated GHG Reduction, Resilience, EOT, and/or Equity benefits.[30] Blue Planet advocates for a "target" cost estimate to be applied to MPIR along with "a project-specific set of metrics and PIMs" to incent the utility to manage project costs.[31]

To address the capital bias issue, the HECO Companies ("HECO") would consider extending the period between rate cases to 4 (and later, 5) years if: "(i) there is an adequate attrition relief mechanism between rate cases and an adequate capital cost recovery mechanism in place, (ii) the existing lag in accruing RAM revenue is eliminated, (iii) appropriate risk mitigation measures are implemented (e.g., symmetric earning sharing mechanism, and Z factor) and (iv) rate design between rate cases is more frequently reviewed."[32]

The HECO Companies suggest that the combination of a rate case moratorium and an attrition relief mechanism ("ARM") "can strengthen cost containment incentives and permit an efficient utility to realize its target rate of return on equity ("ROE") despite a material reduction in regulatory cost."[33] HECO maintains that the ARM utilized in Hawaii, the RAM, should be modified

[29] CA at 28-30.

[30] City and County at 16.

[31] Blue Planet at 17.

[32] HECO at 11, 52-53.

[33] HECO at 46-47.

by establishing a "more remunerative RAM escalator between rate cases."[34] HECO's proposed RAM escalator would not be based on the Companies' actual costs but instead would be based on an inflation index or an approved forecast of baseline plant additions and the approved costs of major projects.[35] Alternatively, the escalator would be depend on a benchmark based on cost increases experienced by U.S. electric utilities with a stretch factor subtracted to further encourage efficiencies.[36]

In comparison, the CA recommends that the "traditional RAM calculations be discontinued, so that a single index-driven increase to target revenues is allowed without regard to the trend in underlying actual costs incurred by the utilities."[37]

HECO points out the over/under earnings risk that is created when extending the period between rate cases and that ESMs can address these risks but may also "dilute the efficiency incentives…[since] the strength of incentives to control costs is stronger at the start of the regulatory period than at the end."[38] HECO states that "[t]his dilution can be addressed to some extent through efficiency carry-over mechanisms ("ECMs"), but that would add significant complexity to the plans."[39] HECO explains how the "ECM is designed to adjust the strength of the incentive and allow the incentive to be sustained until the end of the regulatory period."[40] HECO references the ECM used in Australia.

HECO highlights the importance of rate design and providing customers with appropriate price signals over a longer period between rate cases. To address this issue, HECO maintains that the "RBA needs to be adjusted so that it no longer channels all RAM adjustments into the energy charge."[41] HECO also mentions how rate structures are adjusted in proceedings outside of rate cases in other jurisdictions such as ATCO Gas, PG&E, and the UK.[42]

Ulupono supports extending MRP beyond the current three-year period to approximately five years, but states that it has concerns over extending the MRP beyond five years. Ulupono also supports consolidating the HECO, HELCO and MECO rate case proceedings into one proceeding.[43]

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[34] HECO at 59.

[35] HECO at 59.

[36] HECO at 60.

[37] CA at 28.

[38] HECO at 53, 70.

[39] HECO at 53.

[40] HECO at 70.

[41] HECO at 66.

[42] HECO at 66

[43] Ulupono at 39.

Ulupono states that modifications to the RAM and RAM cap should be considered in this proceeding.[44]

### Revenue Cap

Blue Planet recommends "a movement toward revenue cap regulation as the most comprehensive way to address the three following outcomes: Cost Control, DER Asset Effectiveness, and Grid Investment Efficiency."[45]

Similar to the CA, Blue Planet suggests that "a well-developed PBR regulatory regime should comprehensively encompass and integrate the following elements:

- An extended control period between rate cases, e.g., at least 5 to 8 years.
- A revenue cap escalated annually by an external index.
- Initial rates determined by a current or recent rate case.
- Decoupling of revenues from sales.
- Cost adjustment mechanisms to cover costs (e.g., fuel, purchased power), with appropriate incentives such as cost and risk sharing provisions.
- A dedicated cost recovery mechanism for extraordinary costs.
- A modified, optional, earnings sharing mechanism to limit "excess" profits or losses.
- Performance incentive mechanisms amounting to a significant portion of utility revenues.
- Periodic "check-ins" for monitoring progress."[46]

Blue Planet explains how annual revenue changes "should apply an external index based not on the utility's own costs, but rather an independent, objective factor such as inflation."[47] Blue Planet also offers guidance on how to proceed after the "Revenue Control Period."[48] To a certain degree, Blue Planet's "PBR Revenue Cap" is synonymous with the CA's modified MRP.

### Earnings Sharing Mechanism ("ESM")

The CA, HECO, Ulupono, and Blue Planet discuss considerations for designing an ESM.[49] The CA recommends that the ESM should be "calculated on a basis that fully includes all of the utilities' recorded PIM incentives and penalties, as well as the recorded costs incurred to achieve or avoid such incentives and penalties."[50] The CA presents a straw proposal with details on ROE baseline, a gradually increasing customer participation percentage, and large ROE deadband without

[44] Ulupono at 40.

[45] Blue Planet at 9.

[46] Blue Planet at 12.

[47] Blue Planet at 13.

[48] Blue Planet at 20.

[49] County of Maui, City and County of Honolulu, County of Hawaii, DER Intervenors, HSEA-DERC, and LOL do not discuss the ESM in their briefs.

[50] CA at 43.

sharing.[51] The Consumer Advocate recommends that the ESM have a midpoint that represents a reasonable ROE, and a symmetrical deadband around that midpoint.[52]

HECO similarly recommends that a symmetrical ESM should be established to reduce risk for customers and utilities because an "asymmetric ESM is not compatible with the fair return standard: an extended rate period puts the Companies at risk of earning below the authorized ROE for several years but does not provide a balancing opportunity to earn above the authorized ROE."[53]

Ulupono also proposes a symmetrical ESM that incorporates a "flexible collar" "based on combined revenues from all performance incentive mechanisms."[54] Ulupono maintains that this will "safeguard the utilities' credit rating and access to capital at reasonable rates though 'reverse sharing' if earnings fall below authorized return on equity levels."[55]

Blue Planet discusses the advantages and disadvantages of ESMs. One benefit of ESM is that it can provide customers with "a visible benefit in a revenue cap system and avoid the appearance of 'supranormal' utility profits."[56] A disadvantage of ESMs is that they can "dull and cloud the incentives that a revenue cap regime seeks to offer utilities, threatening the success of the approach."[57] Blue Planet explains how the use of ESM "essentially anchors or pulls back regulation to COSR" because it "requires the calculation of effective 'earnings' and a 'revenue requirement' using a rate base rate-of-return method."[58]

Blue Planet states that the use of a "consumer dividend" or "stretch factor" element of the revenue cap formula may be a preferred approach to an ESM:

> "The consumer dividend reduces the utility's allowed revenue by a predetermined amount written into the revenue cap formula. Under this approach, consumers would save money through the revenue cap regime, but in a less explicit way: rates may increase, but by an objective index, and at a slower rate than they would have without the consumer dividend. An earning sharings approach, of course, may also produce similar end results, but the difference is that the consumer dividend approach more decisively breaks the link between investment and revenues."[59]

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[51] CA at 46.

[52] CA at 65.

[53] HECO at 63-64.

[54] Ulupono at 3

[55] Ulupono at 3.

[56] Blue Planet at 17.

[57] Blue Planet at 17.

[58] Blue Planet at 17-18.

[59] Blue Planet at 18.

## Comments on "Totex" Discussion

Certain Parties present different views on a "total expenditure" or "Totex" approach that equalizes treatment of capital expenditures, operating expenditures, and third-party services. The City and County recommend implementing such an approach.[60] The CA does not support equalizing treatment of capital or operational solutions:

> "A more pragmatic concern also argues against attempted tinkering with cost capitalization rules to adopt any "TOTEX" form of regulation. Utilities that are publicly owned must report financial results in compliance with Generally Accepted Accounting Principles ("GAAP") and cannot arbitrarily modify the capitalization rules contained therein. Compliance with GAAP and Federal Energy Regulatory Commission accounting requirements would quickly frustrate attempts by regulators to dramatically shift costs between expense and capital when setting rates and may yield reported financial results that are damaging to credit metrics and important capital formation goals."[61]

Blue Planet questions capex/opex equalization and contends that it is a "less a discrete regulatory mechanism than an objective that different regulatory regimes may or may not promote. Only by moving away from the rate formula that includes capital and rate base will regulation provide an opportunity for capex/opex equalization."[62]

Relatedly, HECO recommends allowing treatment of certain software development costs as capital costs.[63] HECO believes that this would address the capex bias.

## Integrated Grid Planning ("IGP")

Many Parties discuss the relationship between PBR and the HECO Companies' IGP process. The CA emphasizes that "IGP is one of the most important regulatory mechanisms available to meet the priority goals and outcomes-and is no less important than MRP, metrics, targets, or PIMs."[64] The DER Intervenors note that "priority outcomes must be translated into planning objectives addressed in Integrated Grid Planning efforts."[65] The City and County of Honolulu also mentions the importance of including PBR outcomes in the IGP process.[66]

[60] City and County at 15-16.

[61] CA at 68-70.

[62] Blue Planet at 10.

[63] HECO at 69.

[64] CA at 68.

[65] DER Intervenors at 14.

[66] City and County at 15-16.

## Principles for Designing PIMs and Metrics

Several Parties discuss recommended principles for designing PIMs and metrics and provide PIM and metrics proposals.[67]

The Consumer Advocate offers clarification of the Staff's characterization of metrics, scorecards, and PIMs, and proposes some alternative terminology and definitions for the terms metric, benchmark, peer comparison, targets, PIMs, and scorecards.[68]

The CA proposes the following principles for designing PIMs:

1. "Consider the value of symmetrical versus asymmetrical incentives.
2. Ensure that any incentive formula is consistent with desired outcome.
3. Apply a benefit-cost analysis ("BCA") in developing the PIM.
4. Ensure a reasonable magnitude for the incentive.
5. Tie incentive formula to actions within the control of utilities.
6. Allow incentives to evolve."[69]

The CA recommends that any earnings sharing mechanism calculations account for any PIM awards or penalties in addition to utility costs and revenues to "avoid the inherently complex and controversial accounting analyses that would otherwise be needed to isolate and exclude from ESM all PIM related costs and related revenue impacts."[70] The CA also does not support shared savings mechanisms and argues that they are "inherently complex and potentially controversial, because they rely upon studies of future outcomes, often dependent upon counter-factual assumptions about costs that could have been incurred."[71]

The CA warns that the "utilization of PIMs in the context of traditional regulation with periodic rate cases is inherently problematic" because "it is extremely difficult to isolate, quantify and properly 'match' test year PIM related revenues with the related costs to achieve that level of performance."[72] The CA argues that "these cost/benefit matching problems are avoidable when an MRP is employed."[73] The CA maintains that a "benefit-cost analysis should be conducted prior to implementing a PIM…[and] should be structured like a BCA for a new resource investment."[74]

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[67] CA, HECO, City and County of Honolulu, Ulupono, Blue Planet, and HSEA-DERC propose PIMs. County of Maui, County of Hawaii, DER Intervenors, and LOL do not discuss PIMs.

[68] CA at 49-52.

[69] CA at 62-63

[70] CA at 41.

[71] CA at 68-69.

[72] CA at 42.

[73] CA at 43.

[74] CA at 63.

The CA emphasizes the importance of having a reasonable baseline for PIMs "to ensure that the utility is not rewarded (or penalized) for performance that would have occurred in the absence of the PIM."[75] The CA discusses how determining a baseline is "much easier when the relevant metric has been in place for several years, providing historical performance information and trend data necessary to create reasonable forecasts."[76] The CA points out the importance of designing PIMs in coordination with existing and forthcoming regulatory mechanisms such as the form of multi-year rate plan in place, the ESM in place, and the allowed ROE.[77] Correspondingly, the CA does not recommend PIMs for the cost control outcome "because this outcome is likely to be best addressed through the Consumer Advocate's multi-year rate plan proposal."[78]

HECO emphasizes the importance of designing incentive mechanisms that can be tied to factors that are within management control and points out that "if there are too many individual incentives, the strength of any one incentive will be diluted."[79] HECO also discusses how metrics and incentives developed in this docket should "align and be consistent with operative service and resource plans and other proceedings so that all of these efforts remain coordinated, effective and not at cross-purposes with each other."[80]

In contrast, Blue Planet argues that the principle that metrics should be within the utility's control is not always necessary in PBR. Blue Planet refers to an instance where the Commission did not limit performance incentives to factors solely or mostly within utility control as it adopted the proposed sharing of fuel costs in the ECRC, despite the utility's arguments that it had no control over world fuel prices.[81]

Blue Planet offers recommendations on PIM compensation amounts and a framework for structuring and calibrating PIMs which includes information on how PIMs should be coordinated and weighted relative to each other.[82] Blue Planet suggests beginning with rewards-only PIMs and amending PIMs to add "downside risk to the upside potential"[83] as familiarity with rewards-only PIMs grows. Blue Planet argues that metrics, scorecards, and PIMs alone are "ineffective or insufficient standing alone to achieve many of the priority outcomes Staff Report #3 has

[75] CA at 63.

[76] CA at 64.

[77] CA at 64.

[78] CA at 68.

[79] HECO at 17.

[80] HECO at 16.

[81] Blue Planet at 27.

[82] Blue Planet at 3, 28-32.

[83] Blue Planet at 28.

identified" and "appending metric or PIMs onto the existing COSR structure will address many outcomes only at the symptomatic level, and not achieve the full purpose and promise of PBR."[84]

Similarly, HSEA-DERC contend that "[s]imply adding PIMS onto the existing regulatory framework may not fully address the capital bias problem and likely would increase the overall cost to ratepayers."[85]

HSEA-DERC emphasize the importance of having adequate and transparent data for PIM and metric formation, calibration, and updates.[86] The DER Intervenors emphasize the importance of identifying data necessary to track proposed metrics, including existing studies and additional steps the utilities would need to take to either gather this data or provide it to stakeholders and the Commission.[87] The DER Intervenors highlight the value of determining baselines, data access, the development of new utility tracking accounts, and the development of a utility enterprise data bus with open-API architecture.[88] The DER Intervenors recommend opening several different proceedings to assess data, metrics, ROR accounting, benefit-cost analysis, and utility business models.

The City and County of Honolulu "urges the Commission to consider modifying the current PBR framework (PIMS and revenue adjustment incentive mechanisms) by adding PBR elements primarily based on GHG Reduction."[89] The City and County of Honolulu recommends that in addition to outcomes-based metrics, activity-based and program-based metrics will be important to use "when an outcome either does not yet have easily identifiable data and metrics or is in development mode."[90]

The DER Intervenors recommend that the Commission and Staff map out a general process for developing new and revised metrics. This process would include the "nomination and vetting of metrics proposals… utility development (also with stakeholder input) of mocked-up metrics reports and the utility identification of incremental costs associated with metrics data gathering and reporting."[91]

[84] Blue Planet at 2.

[85] HSEA-DERC at 6.

[86] HSEA-DERC at 7, 16-17.

[87] DER Intervenors at 10.

[88] DER Intervenors at 10-22.

[89] City and County of Honolulu at 15.

[90] City and County of Honolulu at 11-12.

[91] DER Intervenors at 18.

## PIM Proposals

The following summarizes the Parties' suggestions for PIMs that should be included in the PBR framework.

### Consumer Advocate

The CA suggests that PIMs should be applied to the following metrics:[92]

| Outcome | Metrics to Which PIMs Should be Applied |
|---|---|
| Affordability | - Number of disconnections, by month |
| Reliability & Resilience & Cybersecurity | - MW of fast ramping resources<br>- Percent of critical customers served by microgrids<br>- Percent of critical customers experiencing an outage during major event<br>- Participation in joint utility-community resilience planning<br>- Cybersecurity: percent of breaches successful |
| Customer Equity & Engagement | - Community solar: % participation, by class<br>- TOU: % participation, by class<br>- Customer access to hourly or sub-hourly consumption data<br>- Variety, quality, and accessibility of customer data available to customers |
| Customer Satisfaction | - Customer survey |

The Consumer Advocate suggests that PIMs should not be applied to the metrics it identified for the following outcomes: Cost Control, DER Asset Effectiveness, Grid Investment Efficiency, Interconnection Experience, Capital Formation, GHG Reduction, and Electrification of Transportation.[93] The Consumer Advocate suggests that other regulatory mechanisms such as targets, a multi-year rate plan, and/or improved integrated grid planning are more appropriate to apply to these outcomes than PIMs.[94] The Consumer Advocate provides the following table with recommendations for how different regulatory mechanisms should be applied to different outcomes:[95]

[92] CA at 67.

[93] CA at 67.

[94] CA at 17.

[95] CA at 17.

| Goal | CA Proposed Outcome | Metrics | Target | PIM | MRP | Other |
|---|---|---|---|---|---|---|
| Enhance Customer Experience | Affordability | M | T | P | MRP | |
| | Reliability, Resilience, Cybersecurity | M | T | P | | IGP |
| | Customer Equity & Engagement | M | T | P | | |
| | Customer Satisfaction | M | T | P | | |
| Improve Utility Performance | Cost Control | M | T | | MRP | IGP |
| | DER Asset Effectiveness | M | T | | MRP | IGP |
| | Grid Investment Efficiency | M | T | | MRP | IGP |
| | Interconnection Experience | M | T | | | |
| | Capital Formation | M | | | MRP | |
| Advance Societal Outcomes | GHG Reduction | M | T | | | IGP |
| | Electrification of Transportation | M | T | | | IGP |

## HECO

HECO proposes the following PIMs throughout its brief:

- PIM to incent expansion of hosting capacity on congested circuits[96]
- PIM to incent DER on non-congested circuits.[97]
- Longer term DR shared savings PIM.[98]
- Planning Stakeholder Input PIM.[99]
- CBRE development and participation PIM.[100]
- Longer term Procurement PIM for dispatchable and renewable generation.[101]
- EoT – A PIM based on market forecast for electric vehicle and port electrification adoption (upside incentive only).[102]
- EoT – PIM for number of charging ports on each island.[103]

[96] HECO at 7, 22.

[97] HECO at 7, 23.

[98] HECO at 8, 26-28. HECO references New York NWA shared savings incentive here.

[99] HECO at 8, 29.

[100] HECO at 8, 28.

[101] HECO at 13, 84.

[102] HECO at 38.

[103] HECO at 39. HECO points out a major challenge associated with this PIM as the Companies are not able to accurately track the number of public and private charging ports.

- Non-wires alternative ("NWA") PIM.[104]
- Stranded Costs recovery mechanism to encourage the accelerated retirement of an electric utility fossil fuel electric generation.[105]

### City and County of Honolulu

The City and County of Honolulu proposes the following PIMs throughout its brief:

- DER Asset Effectiveness PIM "tied to DER and demand response integration and utilization rates, lowering minimum and must-run generation requirements, and minimizing curtailments of as-available renewable energy."[106]
- GHG Reduction PIM "tied to attainment of a forecasted GHG and/or fuel reduction pathway."[107]
- "A shared carbon savings mechanism (similar to a shared shavings mechanism) that funds a carbon equity fund or the PBF with a percentage of the GHG Reduction PIM."[108]

### Ulupono

Ulupono proposes the following PIMs throughout its brief:

- "Enhanced Procurement Mechanism ("EPM") that allows utility participation in competitive procurement if robust safeguards and protections are in place." Ulupono proposes a shared savings mechanism as an aspect of the EPM.[109]
- PIM for accelerated achievement of the RPS requirement.[110]
- "Fossil Fuel Transition PIM" to incent reduction in fossil fuel use.
    - This PIM would be based on ECRC risk-sharing adjustment and PPAC. Ulupono suggests that the ECRC adjustment should be "modified to eliminate adjustments based on increases or decreases in fuel costs. Instead, the ECRC adjustment would be based on net revenue adjustments due to fuel costs. It therefore would function solely as a penalty under the FF transition PIM ("ECRC penalty")…The

[104] HECO at 8, 54

[105] HECO at 78

[106] City and County of Honolulu at 6. The City and County of Honolulu also suggests that "any PIM should balance the addition of new DER and DR assets with the utilization of existing assets and take into account the benefits of avoided capacity, GHG reduction, and other economic, environmental, and social benefits."

[107] City and County of Honolulu at 9. The City and County of Honolulu also suggests that the Commission "Consider modification of current interim adjustment mechanisms (e.g., RAM and ECAC/ECRC/PPAC) with the addition of the GHG Reduction PIM and then consider fully replacing the current adjustment mechanisms over time with sustainability and resilience adjustment mechanisms."

[108] City and County at 15.

[109] Ulupono at 7-16. Ulupono also discusses the role of competition, safeguards to ensure fair competition, interconnection issues, and the role of the independent observer for an EPM.

[110] Ulupono at 19-22.

ECRC penalty would be coupled with a reward based upon the PPAC ("PPAC reward")."[111]

- Renewable Interconnection PIM for both utility-scale and distributed energy resources. Ulupono recommends that this PIM focus on speed and efficiency of interconnection.[112]
- Supports current PIMs for DR and RFP procurement of utility-scale renewables.[113]
- EoT PIM to track HECO's EoT Strategic Roadmap.[114]
- Microgrids PIM for critical services districts.[115]
- Resilience PIMs "based on vulnerability assessments of the electric system."[116]

### Blue Planet

For the "Interconnection Experience" outcome, Blue Planet does not believe scorecards and PIMs, standing alone, will provide effective incentives. Blue Planet maintains that "Layering scorecards or PIMs over the traditional regulatory system does not directly address… the underlying bias toward utility investments."[117]

[111] Ulupono at 19-22.

[112] Ulupono at 31. Ulupono suggests that surveys of end users could be used for this PIM.

[113] Ulupono at 32-34.

[114] Ulupono at 35.

[115] Ulupono at 36.

[116] Ulupono at 38.

[117] Blue Planet at 9.

## Metrics

The following table summarizes metrics proposed by the Parties:

| Outcome | Existing Metrics | Proposed Metrics |
|---|---|---|
| **Affordability** | Consumer Advocate[118]<br>- ¢/kWh, by class<br>- Contributing cost components to customer rates | Consumer Advocate[119]<br>- Average annual bill, by class<br>- Average annual bill as % of income, by class<br>- Average annual bill as % of income for LMI customers<br>- Bill stability: percent change in average annual bill, by class<br>- Percent of res. customers in arrearage plans<br>- Number of disconnections, by month and class. (T, PIM)<br>- Ratio of res. customers in arrearage plans to customer disconnections, by month (T)<br><br>City and County of Honolulu[120]<br>- average monthly bill by rate class<br>- average monthly bill as a percentage of disposable income or net income after taxes and rent<br>- number of LMI targeted programs launched<br>- budget level or amount of funds supplied to PBF or LMI-targeted programs<br><br>County of Hawaii[121]<br>- Degree to which average residential and customer bills are lowered over the next 10 years from current levels<br>- Average customer bill as a percentage of household income (energy burden)<br>- HECO rates compared to similarly situated utilities in other states<br><br>Blue Planet[122]<br>- Average cost of service or bills by customer class<br><br>DER Intervenors[123]<br>- Total household/business energy burden |

[118] CA at 56

[119] CA at 56. Note that (T), (T, PIM) indicate that the CA proposes the targets (T) and/or PIMs should be applied to certain metrics.

[120] City and County of Honolulu at 2-3

[121] COH at 4.

[122] Blue Planet at 24

[123] DER Intervenors at 18

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|---|---|---|
| **Reliability**[124] | Consumer Advocate[125]<br>- SAIDI<br>- SAIFI<br>- CAIDI<br>- MAIFI<br>- Response time | Consumer Advocate[126]<br>- SAIDI, SAIFI, and MAIFI by circuits<br>- Resilience: SAIDI, SAIFI, CAIDI response time on black sky days.<br>- MW of fast ramping resources (T, PIM)<br>- MW of capacity and percent of customers served by microgrids<br>- Percent of critical customers served by microgrids (T, PIM)<br>- Percent of critical customers experiencing an outage during a major event (T, PIM)<br>- Duration of outages of critical customers<br>- Participation in joint utility-community resilience planning (T, PIM)<br>- Cybersecurity: number of attempted breaches<br>- Cybersecurity: percent of breaches successful (T, PIM)<br>- Cybersecurity: adoption of EPRIs metrics (T)<br>- Cybersecurity: adherence to NERC standards (T)<br>- Cybersecurity: information sharing with other entities/participation in joint planning (T)<br>- Variety, quality, and accessibility of customer data available to<br>- Customers (PIM)<br><br>City and County of Honolulu[127]<br>- Current PIMs are an effective starting point<br>- County of Hawaii[128]<br>- Conventional reliability metrics are sufficient to address the goal |
| **Interconnection Experience** | - "Weekly Interconnection Queue Reports"<br><br>- "Quarterly DER Interconnection Reports." | Consumer Advocate[129]<br>- Time in interconnection queue (T)<br>- Results of DER developer satisfaction survey (T)<br>- Results of IPP developer satisfaction survey (T)<br><br>HECO Companies[130]<br>- MW proposed in Subscriber Organizations' ("SO") submitted CBRE applications, including proposals for utility self-build facilities<br>- MW of applications approved by the Companies and allocated to SOs (or in the case of a utility self-build project, approved by the Commission)<br>- MW of CBRE with completed IRS<br>- MW of CBRE under construction<br>- MW of CBRE installed measured at the Commercial Operations Date ("COD")<br><br>County of Maui[131]<br>- Time to interconnect customers |

[124] The CA believes the outcomes, Resilience and Cybersecurity, should be included in this outcome.

[125] CA at 56

[126] CA at 56

[127] City and County of Honolulu at 3.

[128] COH at 5

[129] CA at 57-58

[130] HECO at 8-9, 29-32.

[131] Maui County at 6-7

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|---|---|---|
| | | Ulupono[132]<br>- Speed and efficiency could be evaluated in relation to exceeding the time periods and deadlines set forth in existing tariff rules governing utility interconnection of DER.<br><br>Blue Planet[133]<br>- Interconnection time<br>- Cost to interconnect<br>- DER Customer Survey results<br>- Utility-Scale developer survey results<br><br>DER Intervenors[134]<br>- metrics relating to cost, time, predictability, and transparency<br>- customer satisfaction<br><br>HSEA-DERC[135]<br>- Time to interconnect DER Systems by general location<br>- Real-time updates of "Weekly Interconnection Queue Reports" and "Quarterly DER Interconnection Reports" on HECO's Websites<br>- Customer facing dashboard that generates reports on the status of customers' interconnection applications |
| **Customer Engagement[136]** | Consumer Advocate[137]<br>- Number of NEM program participants<br>- Capacity of all NEM resources (MW)<br>- Total energy (kWh) exported by NEM resources, excluding feed-in tariff and standard interconnection<br><br>HECO Companies<br>- MW of installed CBRE capacity | Consumer Advocate[138]<br>- EE: % participation, by class<br>- DR: % participation, by class (T)<br>- PV: % customers with installation, by class<br>- Community solar: % participation, by class (T)<br>- Other DG: % customers with installation, by class<br>- Storage: % installations, by class (T)<br>- TOU: % participation, by class (T)<br>- TOU: % of all customers participating (T)<br>- Percent of LMI households participating in EE, DR, PV, DG, Storage, or TOU (T)<br>- Customer access to hourly or sub-hourly consumption data (T)<br>- Third-party service access to customer data. (T)<br>- Variety, quality, and accessibility of customer data available to customers/third-parties. (T)<br>- Consumer education |

[132] Ulupono at 31.

[133] Blue Planet at 25

[134] DER Intervenors at 18

[135] HSEA DERC at 9-10

[136] The CA believes this outcome should be amended to Customer Equity and Engagement

[137] CA at 57-58

[138] CA at 57-58

| | | |
|---|---|---|
| | | HECO Companies[139]<br>- Number of low-to-moderate income ("LMI") customers enrolled in CBRE[140]<br>- number of renters and multi-unit dwelling customers enrolled in CBRE<br><br>City and County of Honolulu[141]<br>- attainment of project milestones and budgets for critical public works projects<br>- smart meter deployments<br>- customer service polls and surveys.<br><br>County of Hawaii[142]<br>- low-income customers in DR and TOU programs, benchmarked against similarly situated utilities<br><br>Ulupono[143]<br>- percentage of CBRE applicants who are unable to become full program participants due to limits in program capacity (rather than delays in program administration)<br>- Percentage of low- and moderate-income applicants who are program participants<br><br>DER Intervenors[144]<br>customer use of non-utility services to obtain household/business energy services. |
| **Cost Control** | | Consumer Advocate[145]<br>- Total energy costs per customer<br>- Total capacity costs per customer<br>- Generation assets per customer<br>- Transmission assets per customer & per mile<br>- Distribution assets per customer & per mile<br>- O&M spend per customer<br>- Billing & customer service spend per customer<br>- G&A spend per customer<br><br>City and County of Honolulu[146]<br>- Actual vs. planned expenditures-capital and operating expenses |

[139] HECO at 32 -33

[140] HECO points out that LMI must be defined and suggests aligning the definition of LMI customers with income levels used in the "ALICE" ("Asset Limited, Income Constrained, Employed") definition in Aloha United Way's 2017 report entitled. See HECO at 32.

[141] City and County of Honolulu at 4

[142] COH at 6.

[143] Ulupono at 37

[144] DER Intervenors at 18

[145] CA at 57-58

[146] City and County of Honolulu at 5

| | | |
|---|---|---|
| | | - avoided energy costs vs. peers<br>- Levelized cost of energy ("LCOE") of most recent grid-scale power purchase agreements ("PPAs")<br>- Effective rates vs. LCOE of most recent grid-scale PPAs.<br><br>Blue Planet[147]<br>- overall or project-specific utility costs |
| **DER Asset Effectiveness** | Consumer Advocate[148]<br>- DR: customer load (MW)<br>- DR: # events<br>- Storage: amount (MW)<br>- Storage: amount (MWh) | Consumer Advocate[149]<br>- EE: MWh savings as % sales, by class<br>- EE: MW savings as % load, by class<br>- DR: Annual maximum MW reduction as % load, by class<br>- DR: MW enrolled as% load, by class (T)<br>- PV: MWh generated as % sales, by class<br>- PV: MW installed as % load, by class<br>- Other DG: MWh generated as% sales, by class (T)<br>- Other DG: MW installed as% load, by class (T)<br>- Storage: MWh installed energy capacity as% sales, by class (T)<br>- Storage: MW installed capacity as % load, by class (T)<br>- Microgrids: MW as% load, by class (T)<br>- Microgrids: % customers served by a microgrid, by class (T)<br>- NWAs: MW as % of load (T)<br>- NWAs: % customers participating (T)<br>- NWAs: savings per year<br><br>City and County of Honolulu[150]<br>- DER/DR energy and capacity as a percentage of Total and System Renewable Energy/Capacity<br>- DER/DR energy and capacity as a percentage of utility and independent power producer ("IPP ") generation<br>- Renewable energy curtailment as a percentage of system renewable energy and IPP curtailable<br><br>DER Intervenors[151]<br>- Percentage of energy services provided from DERs, by provider (utility, non-utility, public sector).<br><br>HSEA-DERC[152]<br>- MW's of DER's interconnected on the grid and enrolled in grid-supporting programs |

[147] Blue Planet at 24

[148] CA at 57-58

[149] CA at 57-58

[150] City and County of Honolulu at 6

[151] DER Intervenors at 18

[152] HSEA-DERC at 13-14

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|---|---|---|
| | | - percentage of grid supporting services (regulation, FFR) provided by DER's versus traditional resources<br>- revenues paid to DER's for providing grid-supporting services (revenues here include bill credits) |
| **Grid Investment Efficiency** | - | Consumer Advocate[153]<br>- Implementation of a standardized NWA procurement process (T)<br>- IGP survey: stakeholder engagement (T)<br>- IGP survey: evaluation of resources (T)<br>- IGP survey: selection of resources (T)<br>- IGP survey: action plan and follow-through (T)<br><br>City and County of Honolulu[154]<br>- Amount of money invested in PBF or LMI programs<br>- Deployment of PBF or LMI focused funds<br><br>DER Intervenors[155]<br>- Electric load factor, as a key indicator of efficient usage and investment |
| **Capital Formation** | Consumer Advocate<br>- Ratemaking return on common equity<br>- Credit ratings | Consumer Advocate<br>- None. See CA's proposed earnings sharing mechanism.<br><br>HECO Companies[156]<br>- Scorecard targeting higher credit ratings could be adopted<br><br>City and County of Honolulu[157]<br>- net shareholder equity<br>- RPS percentage<br>- Amount of total grid investments by the Utility and third-parties.<br><br>Capital Formation[158]<br>Blue Planet continues to have reservations about a metric and PIM based on the "utility credit rating," which could magnify a bias in favor of protecting the incumbent utility, rather than promoting broader market competition and performance<br><br>DER Intervenors[159]<br>- DER sector revenue growth rate, against inflation, by provider (utility, non-utility, public sector).<br>- green |

[153] CA at 60

[154] City and County at 7

[155] DER Intervenors at 18

[156] HECO at 11, 73

[157] City and County at 8.

[158] Blue Planet at 26

[159] DER Intervenors at 18

| | | |
|---|---|---|
| | | - infrastructure lending and financial support for electricity services and products provided to residential and business customers<br>- healthy and competitive returns for non-utility investors<br>- reductions in capital requirements (not just reductions in the cost of capital) for utilities |
| **Social Equity** | | Consumer Advocate[160]<br>- See Customer Engagement row above<br><br>HECO Companies[161]<br>- level of subsidization of CBRE by all other customers<br><br>Maui County[162]<br>- low-to-moderate (LMI) participation in programs<br><br>City and County of Honolulu[163]<br>- money invested in the PBF or LMI programs<br>- deployment of PBF or LMI focused funds.<br><br>County of Hawaii[164]<br>- Ratio of current customers receiving assistance through the Low Income Home Energy Assistance Program (LIHEAP) that participate in DER or CBRE programs<br><br>- Ratio of current customers receiving assistance through the Special Medical Needs<br>- Program that participate in DER or CBRE programs<br><br>- Energy efficiency programs' reach and impact on low-income customers<br><br>DER Intervenors[165]<br>- household energy burden and small business energy burden |
| **GHG Reduction** | Consumer Advocate[166]<br>- RPS compliance<br>- System renewable energy<br>- Total renewable energy | - Consumer Advocate[167]<br>- Annual CO2 emissions (T)<br>- Annual CO2 per customer, by class (T)<br>- Annual CO2 per MWh (T)<br>- Percent of total generation from fossil fuels (T)<br>- Percent of total generation from renewables |

[160] CA at 57-58. The CA believes this outcome should be amended to Customer Equity and Engagement.

[161] HECO at 8-9, 34

[162] Maui County at 8

[163] City and County at 9.

[164] COH at 11.

[165] DER Intervenors at 18.

[166] CA at 59.

[167] CA at 59.

| | | |
|---|---|---|
| | | - Percent of renewable generation from IPPs<br>- Percent of renewable generation from DERs<br>- Average heat rate/aggregate power plant efficiency (T)<br><br>HECO Companies[168]<br>- Mass-based CO2 equivalent (CO2e) emissions in tons per year from all major generation sources (Company-owned and IPP assets); and<br>- Carbon Intensity (CO2e/MWh)<br>- System wide fossil fuel generation as measured by MW-hours per fuel type<br>- Both Company and Independent Power Producer ("IPP") GHG emissions (Total CO2e) can be reported (to the extent the Companies have legal access to IPP GHG emissions)<br><br>Maui County[169]<br>- GHG emissions per gross electrical production<br>- Full life cycle emission vs. generation emissions<br><br>City and County of Honolulu[170]<br>- Annual or quarterly GHG reductions in metric tons of carbon dioxide equivalent relative to forecast<br>- Annual fuel use reductions in barrels of crude oil equivalent relative to forecasted reduction pathway.<br><br>County of Hawaii[171]<br>- A carbon intensity metric should be used for the full electrical system, not only for utility generation or from individual point sources<br><br>Blue Planet[172]<br>- CO2e per kW<br>- CO2e per customer<br>- Sector wide CO2e<br><br>DER Intervenors[173]<br>- Progress toward GHG reduction goals accomplishment, total Hawaii, by island, and by sector (e.g. utility, transportation, etc.)<br><br>Life of the Land[174]<br>- Lifecycle greenhouse gas emissions per BTU of energy sold |

[168] HECO at 9, 34, 36

[169] Maui County at 8

[170] City and County at 10

[171] COH at 9

[172] Blue Planet at 25

[173] DER Intervenors at 17

[174] LOL at 2.

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|---|---|---|
| **Electrification of Transportation** | Consumer Advocate[175]<br>- TOU: % participation for EV and non-EV groups. | Consumer Advocate[176]<br>- Number of EVs added per year (T)<br>- Percent of EVs in DR programs (T)<br>- Percent of EVs on TOU rates (T)<br><br>HECO Companies[177]<br>- efficient electrification measured in equivalent EV adoption (includes cars, buses and cranes and other port electrification)<br>- number of public chargers installed<br>- number of chargers installed at multi-unit dwellings<br>- number of workplace charging customers.<br><br>Maui County[178]<br>- Electricity cost per mile vs. national average gasoline cost per mile ("$/mile-electric" verses a "$/mile-gasoline")<br><br>City and County of Honolulu[179]<br>- Achievement of scheduling and budget milestones established in EoT Strategic Roadmap and IGP<br><br>County of Hawaii[180]<br>- Cautions ascribing credit for EV adoption to HECO<br><br>Ulupono[181]<br>- amount of energy, as measured in kWh, supplied and used by EVs and the corresponding reductions in fossil fuel use and in GHG emissions<br>- Number of EVs<br>- Number of charging stations |
| **Resilience** | | Consumer Advocate<br>- SAIDI, SAIFI, CAIDI response time on black sky days.<br>- MW of fast ramping resources<br>- MW of capacity and percent of customers served by microgrids<br>- Percent of critical customers served by microgrids<br>- Percent of critical customers experiencing an outage during a major event<br>- Duration of outages of critical customers<br>- Participation in joint utility-community resilience planning<br>- Cybersecurity: number of attempted breaches<br>- Cybersecurity: percent of breaches successful |

[175] CA at 59.

[176] CA at 59.

[177] HECO at 9-10,37-38. HECO notes that it does not yet have the systems or tools in place to segregate out all kwh sales related to vehicles or other equipment. See HECO at 37.

[178] Maui County 8-9

[179] City and County at 8

[180] COH at 14

[181] Ulupono at 35

| | | |
|---|---|---|
| | | - Cybersecurity: adoption of EPRIs metrics<br><br>HECO Companies[182]<br>- Community resilience education and awareness (this might include tracking customers subscribed for outage map reporting or number of customers receiving emergency preparedness booklets and materials);<br>- Geographical, technological and resource diversity of resources (generation, storage, T&D);<br>- Smartening of the grid to improve situational awareness, advanced and earlier sensing of pending events that may put service at risk, and the ability to take action and respond to events as they occur;<br>- Microgrid services and non-wire alternatives that take advantage of new technology options to fulfil a resilience objective;<br>- Adequate grid maintenance, to enhance the reliability and use of existing infrastructure investments;<br>- In-depth monitoring of detection systems, leading to containment and remediation of cyber, physical and environmental events and intrusions of the electric system and networks, including plants and substations. Enhance measures in place to respond to and mitigate attempts to gain cyber or physical access to utility operational technology systems;<br>- Strategic grid hardening to ensure that critical segments of the electric grid and critical loads are designed and built to a higher standard of resilience; and<br>- An incident management and restoration process that allows for timely, effective, and efficient repair of infrastructure affected by an event and rapid restoration of electric service to customers.<br><br>*Longer-Term Metrics*<br>- Generation to load geographic match/mismatch;<br>- % generation balanced across parts of each island served;<br>- Number or percent of customers with AMI with outage detection;<br>- Number of distribution feeders with DA/FLISR (self -healing circuits) and other restorative features built and operating within T&D systems;<br>- % of system or % of customers/customer load that can operate in an island mode for emergency or other contingency events;<br>- Cyber protection and defense performance measures and assessments of systems, scanned vulnerability percentage, policies and alignment to security frameworks, and adequate staffing supporting cyber and security monitoring, telecom, and operating systems;<br>- % of system or number of circuits built to enhanced or elevated design standards (seismic, wind, etc.); (42)<br>- Annual training and personnel certification requirements in storm response (% of IMT positions / staff certified in ICS training). A regular cadence of Table Top Exercises (TTX) conducted to simulate events to enhance reaction and communication and train personnel; and/or Incorporation of lessons-learned from other incidents. For example, regular updating of IMT handbook, incident checklists, etc. based upon lessons-learned from past experiences (either from within the industry or from other utilities). (43) |

[182] HECO at 41-43.

| | | |
|---|---|---|
| | | Maui County<br>- Person-days not served[183]<br><br>City and County of Honolulu[184]<br>- delivery of a grid vulnerability assessment with IGP process<br>- level of grid resilience investments, e.g., upgrading transmission and distribution infrastructure to latest codes, grid, and network detection equipment<br>- meeting resilience planning budget and scheduling milestones<br>- number of community resilience meetings<br>- measures that capture redundancy and recovery capabilities.<br><br>Ulupono[185]<br>- microgrid services provided to critical services districts<br>- duration a microgrid can remain islanded<br>- vulnerability assessments of quantified forecasted impacts to poles, wires, generation facilities and related infrastructure<br><br>DER Intervenors[186]<br>- Imported energy, by type, by island, by sector, in both real and relative terms |
| **Other** | Customer Satisfaction<br>- Customer survey (T, PIM)<br>- Complaints (T)<br>- % calls within 30 secs<br>- Billing accuracy (T)<br>- Meters read (T)<br>- Appointments met (T)<br>- Order intervals (T)<br><br>System Efficiency<br>- Recovery of fuel and purchased energy costs (in $)<br>- IPP generation (% of total generation)<br>- IPP generation (MWh)<br>- Energy losses (%) from company use, theft, heat losses, etc.<br>- Weighted forced outage rate - demand. | Consumer Advocate [188]<br>- *Customer Satisfaction*<br>- Results of independent surveys, e.g., J.D. Power<br><br>- *System Efficiency*<br>- Recovery of fuel costs (in cents/kWh)<br>- Recovery of purchased energy costs (cents/kWh)<br>- IPP capacity(% total capacity)<br>- Annual energy (GWh), by class<br>- Annual energy per customer, by class<br>- Annual peak (MW), by class<br>- Annual peak per customer, by class<br>- Annual load factor, by class<br>- Ratio of annual capex/opex<br><br>County of Hawaii[189]<br>- COH recommends not to include a metric on the amount of third-party owned generation (MW) as percentage of total system generation (MW), as indicated in Staff Report #1 |

[183] Maui County at 9.

[184] City and County at 11

[185] Ulupono at 36-37, 39

[186] DER Intervenors at 18

[188] CA at 56-57

[189] COH at 9

| | | |
|---|---|---|
| | - Weighted forced outage factor.<br><br><u>Renewable Energy</u><br>- Renewable energy curtailment: curtailment as % of total IPP curtailable generation that is curtailed, and as% of total renewable generation.[187]<br><br><u>Safety</u><br>- Total case incident rate: number of work-related injuries and illnesses per 100 employees.<br>- Lost time rate: same as total case incident rate but counting only incidents that prevent employee from working full shift.<br>- Public safety incidents: count of injuries to members of the general public allegedly caused by utility service or operations that result in hospitalization or death. | |

[187] CA at 59-60

*Staff Proposal for Updated Performance-Based Regulations*
*Proceeding to Investigate Performance-Based Regulation (2018-0088)*

# *APPENDIX C*

*Operational Efficiency – Comparison to Selected Utilities*

## APPENDIX C

## Operational Efficiency – Comparison to Utilities in the Continental U.S.

| O&M Per Customer 2017 | | | | | | |
|---|---|---|---|---|---|---|
| | | Transmission | Distribution | Customer Service | A&G | Total |
| 1 | Emera Maine | -$95 | $104 | $60 | $37 | $105 |
| 2 | Virginia Electric and Power Company | -$3 | $75 | $31 | $63 | $171 |
| 3 | North Central Power Co., Inc. | $1 | $105 | $53 | $19 | $178 |
| 4 | Northwestern Wisconsin Electric Company | $11 | $101 | $62 | $19 | $194 |
| 5 | Kingsport Power Company | $17 | $109 | $33 | $37 | $196 |
| 6 | Public Service Company of Colorado | $38 | $67 | $23 | $77 | $206 |
| 7 | Jersey Central Power & Light Company | $26 | $84 | $39 | $61 | $210 |
| 8 | Nevada Power Company | $64 | $29 | $45 | $71 | $210 |
| 9 | Sierra Pacific Power Company | $37 | $79 | $26 | $75 | $219 |
| 10 | Tampa Electric Company | $19 | $65 | $52 | $95 | $232 |
| 11 | Potomac Edison Company | $64 | $77 | $35 | $58 | $235 |
| 12 | Pennsylvania Power Company | $31 | $98 | $42 | $66 | $237 |
| 13 | Metropolitan Edison Company | $27 | $91 | $54 | $69 | $240 |
| 14 | Duke Energy Florida, LLC | $26 | $84 | $34 | $94 | $243 |
| 15 | PacifiCorp | $110 | $106 | $46 | $6 | $268 |
| 16 | Duke Energy Carolinas, LLC | $21 | $108 | $41 | $95 | $270 |
| 17 | Duquesne Light Company | $21 | $70 | $45 | $139 | $275 |
| 18 | Public Service Electric and Gas Company | $49 | $75 | $108 | $50 | $282 |
| 19 | Pennsylvania Electric Company | $58 | $111 | $49 | $66 | $285 |
| 20 | Entergy New Orleans, Inc. | $42 | $84 | $53 | $102 | $287 |
| 21 | Duke Energy Progress, LLC | $25 | $99 | $33 | $133 | $294 |
| 22 | Duke Energy Ohio, Inc. | $67 | $132 | $35 | $54 | $294 |
| 23 | Arizona Public Service Company | $68 | $90 | $49 | $77 | $296 |
| 24 | MidAmerican Energy Company | $100 | $115 | $36 | $37 | $301 |
| 25 | Louisville Gas and Electric Company | $38 | $111 | $33 | $122 | $305 |
| 26 | West Penn Power Company | $106 | $93 | $44 | $64 | $307 |
| 27 | Puget Sound Energy, Inc. | $122 | $67 | $43 | $76 | $310 |
| 28 | South Carolina Electric & Gas Co. | $32 | $78 | $65 | $140 | $317 |
| 29 | Public Service Company of New Mexico | $70 | $40 | $29 | $171 | $318 |
| 30 | Southern California Edison Company | $44 | $103 | $30 | $138 | $319 |
| 31 | Entergy Texas, Inc. | $62 | $84 | $45 | $125 | $323 |
| 32 | Alaska Electric Light and Power Company | $42 | $185 | $70 | $30 | $327 |
| 33 | Consolidated Edison Company of New York, Inc. | $51 | $150 | $64 | $60 | $328 |

| O&M Per Customer 2017 | | | | | | |
|---|---|---|---|---|---|---|
| | | Transmission | Distribution | Customer Service | A&G | Total |
| 34 | Superior Water, Light and Power Company | $9 | $80 | $105 | $135 | $329 |
| 35 | Entergy Mississippi, Inc. | $44 | $105 | $51 | $121 | $329 |
| 36 | Pacific Gas and Electric Company | $55 | $133 | $39 | $110 | $340 |
| 37 | Idaho Power Co. | $47 | $94 | $43 | $159 | $343 |
| 38 | Georgia Power Company | $42 | $107 | $56 | $118 | $347 |
| 39 | El Paso Electric Company | $51 | $53 | $47 | $197 | $348 |
| 40 | Baltimore Gas and Electric Company | $37 | $156 | $43 | $113 | $349 |
| 41 | Kentucky Utilities Company | $63 | $102 | $62 | $124 | $351 |
| 42 | Upper Michigan Energy Resources Corporation | $177 | $118 | $32 | $25 | $351 |
| 43 | Commonwealth Edison Company | $107 | $117 | $57 | $79 | $362 |
| 44 | Gulf Power Company | $58 | $105 | $58 | $141 | $364 |
| 45 | UGI Utilities, Inc. | $112 | $113 | $50 | $88 | $364 |
| 46 | Golden State Water Company | $3 | $89 | $32 | $239 | $366 |
| 47 | PPL Electric Utilities Corporation | $104 | $110 | $48 | $103 | $366 |
| 48 | Entergy Louisiana, LLC | $87 | $81 | $50 | $139 | $368 |
| 49 | Cleco Power LLC | $122 | $106 | $51 | $55 | $369 |
| 50 | UNS Electric, Inc. | $181 | $72 | $43 | $76 | $372 |
| 51 | Tucson Electric Power Company | $73 | $56 | $49 | $198 | $376 |
| 52 | Union Electric Company | $79 | $115 | $55 | $122 | $377 |
| 53 | Avista Corporation | $88 | $87 | $44 | $160 | $378 |
| 54 | Ohio Power Company | $166 | $121 | $49 | $40 | $378 |
| 55 | Ameren Illinois Company | $49 | $195 | $43 | $93 | $380 |
| 56 | Pioneer Power and Light Company | $0 | $175 | $22 | $185 | $381 |
| 57 | Consumers Energy Company | $193 | $102 | $34 | $50 | $383 |
| 58 | San Diego Gas & Electric Co. | $61 | $101 | $35 | $189 | $388 |
| 59 | NorthWestern Corporation | $101 | $103 | $32 | $154 | $393 |
| 60 | Duke Energy Indiana, LLC | $101 | $121 | $41 | $120 | $395 |
| 61 | Duke Energy Kentucky, Inc. | $122 | $129 | $43 | $83 | $396 |
| 62 | Entergy Arkansas, Inc. | $59 | $120 | $53 | $159 | $398 |
| 63 | Wisconsin Electric Power Company | $223 | $70 | $46 | $55 | $398 |
| 64 | Indianapolis Power & Light Company | $82 | $88 | $45 | $183 | $408 |
| 65 | Florida Power & Light Company | $20 | $295 | $23 | $71 | $412 |
| 66 | Ohio Edison Company | $254 | $72 | $39 | $48 | $415 |
| 67 | PECO Energy Company | $114 | $161 | $61 | $82 | $418 |
| 68 | Cleveland Electric Illuminating Company | $265 | $72 | $40 | $50 | $427 |
| 69 | Atlantic City Electric Company | $40 | $165 | $117 | $109 | $431 |

| O&M Per Customer 2017 | | | | | | |
|---|---|---|---|---|---|---|
| | | Transmission | Distribution | Customer Service | A&G | Total |
| 70 | Public Service Company of New Hampshire | $99 | $138 | $56 | $132 | $431 |
| 71 | Black Hills Colorado Electric Utility Company, LP | $64 | $153 | $40 | $178 | $436 |
| 72 | Connecticut Light and Power Company | $109 | $142 | $74 | $115 | $441 |
| 73 | Oncor Electric Delivery Company LLC | $287 | $73 | $5 | $79 | $444 |
| 74 | Kansas City Power & Light Company | $159 | $104 | $55 | $114 | $446 |
| 75 | Delmarva Power & Light Company | $47 | $163 | $105 | $131 | $447 |
| 76 | Oklahoma Gas and Electric Company | $201 | $115 | $29 | $90 | $453 |
| 77 | Western Massachusetts Electric Company | $104 | $110 | $96 | $144 | $454 |
| 78 | Potomac Electric Power Company | $37 | $180 | $104 | $144 | $465 |
| 79 | KCP&L Greater Missouri Operations Company | $146 | $108 | $59 | $144 | $468 |
| 80 | Portland General Electric Company | $120 | $147 | $67 | $137 | $471 |
| 81 | Central Hudson Gas & Electric Corporation | $41 | $196 | $74 | $163 | $473 |
| 82 | DTE Electric Company | $160 | $140 | $82 | $87 | $475 |
| 83 | Northern States Power Company - MN | $252 | $76 | $38 | $115 | $487 |
| 84 | Alabama Power Company | $60 | $162 | $61 | $202 | $489 |
| 85 | Indiana Michigan Power Company | $238 | $114 | $26 | $103 | $489 |
| 86 | Rochester Gas and Electric Corporation | $27 | $173 | $178 | $100 | $490 |
| 87 | Empire District Electric Company | $146 | $145 | $49 | $157 | $497 |
| 88 | Orange and Rockland Utilities, Inc. | $68 | $219 | $102 | $112 | $504 |
| 89 | Southwestern Electric Power Company | $224 | $161 | $38 | $84 | $509 |
| 90 | Toledo Edison Company | $337 | $64 | $48 | $62 | $511 |
| 91 | MDU Resources Group, Inc. | $258 | $107 | $32 | $110 | $512 |
| 92 | Narragansett Electric Company | $161 | $124 | $57 | $173 | $519 |
| 93 | Niagara Mohawk Power Corporation | $61 | $214 | $58 | $183 | $520 |
| 94 | Appalachian Power Company | $243 | $155 | $42 | $75 | $521 |
| 95 | Rockland Electric Company | $30 | $257 | $86 | $151 | $525 |
| 96 | Public Service Company of Oklahoma | $251 | $177 | $27 | $70 | $528 |
| 97 | CenterPoint Energy Houston Electric, LLC | $355 | $99 | $13 | $66 | $533 |
| 98 | New York State Electric & Gas Corporation | $47 | $258 | $147 | $75 | $536 |
| 99 | Wisconsin Public Service Corporation | $314 | $74 | $32 | $114 | $539 |
| 100 | Monongahela Power Company | $224 | $169 | $52 | $95 | $541 |
| 101 | Northern States Power Company - WI | $311 | $102 | $37 | $105 | $556 |
| 102 | Lockhart Power Company | $47 | $155 | $75 | $283 | $560 |
| 103 | Central Maine Power Company | $298 | $157 | $52 | $63 | $572 |
| 104 | Texas-New Mexico Power Company | $359 | $104 | $15 | $95 | $573 |

| O&M Per Customer 2017 | | | | | | |
|---|---|---|---|---|---|---|
| | | Transmission | Distribution | Customer Service | A&G | Total |
| 105 | Wisconsin Power and Light Company | $368 | $61 | $30 | $116 | $580 |
| 106 | HECO Companies | $41 | $150 | $116 | $284 | $591 |
| 107 | Madison Gas and Electric Company | $273 | $94 | $54 | $167 | $593 |
| 108 | NSTAR Electric Company | $365 | $82 | $63 | $86 | $596 |
| 109 | Upper Peninsula Power Company | $130 | $268 | $91 | $107 | $598 |
| 110 | Southern Indiana Gas and Electric Company, Inc. | $123 | $111 | $47 | $279 | $622 |
| 111 | Unitil Energy Systems, Inc. | $384 | $116 | $43 | $80 | $624 |
| 112 | Northern Indiana Public Service Company | $99 | $106 | $35 | $379 | $634 |
| 113 | Green Mountain Power Corporation | $374 | $138 | $22 | $92 | $637 |
| 114 | Fitchburg Gas and Electric Light Company | $303 | $147 | $95 | $123 | $669 |
| 115 | Mississippi Power Company | $59 | $168 | $84 | $345 | $671 |
| 116 | Westar Energy (KPL) | $352 | $112 | $45 | $174 | $683 |
| 117 | Kentucky Power Company | $264 | $292 | $36 | $87 | $686 |
| 118 | Kansas Gas and Electric Company | $404 | $123 | $43 | $162 | $732 |
| 119 | Liberty Utilities (Granite State Electric) Corp. | $495 | $157 | $50 | $27 | $733 |
| 120 | Otter Tail Power Company | $236 | $135 | $98 | $277 | $756 |
| 121 | Cheyenne Light, Fuel and Power Company | $454 | $102 | $19 | $218 | $793 |
| 122 | Dayton Power and Light Company | $270 | $132 | $177 | $232 | $812 |
| 123 | Southwestern Public Service Company | $491 | $93 | $47 | $161 | $814 |
| 124 | Black Hills Power, Inc. | $380 | $176 | $43 | $309 | $908 |
| 125 | United Illuminating Company | $472 | $322 | $116 | $5 | $916 |
| 126 | Interstate Power and Light Company | $640 | $70 | $53 | $158 | $928 |
| 127 | Mt. Carmel Public Utility Company | $155 | $327 | $105 | $387 | $974 |

Source: http://www2.bain.com/utilityOE/default.asp?c=p using FERC Form 1 data

*Staff Proposal for Updated Performance-Based Regulations*
*Proceeding to Investigate Performance-Based Regulation (2018-0088)*

# *APPENDIX D*

*Examining a PBR Framework within the Broader Regulatory Landscape*

## APPENDIX D

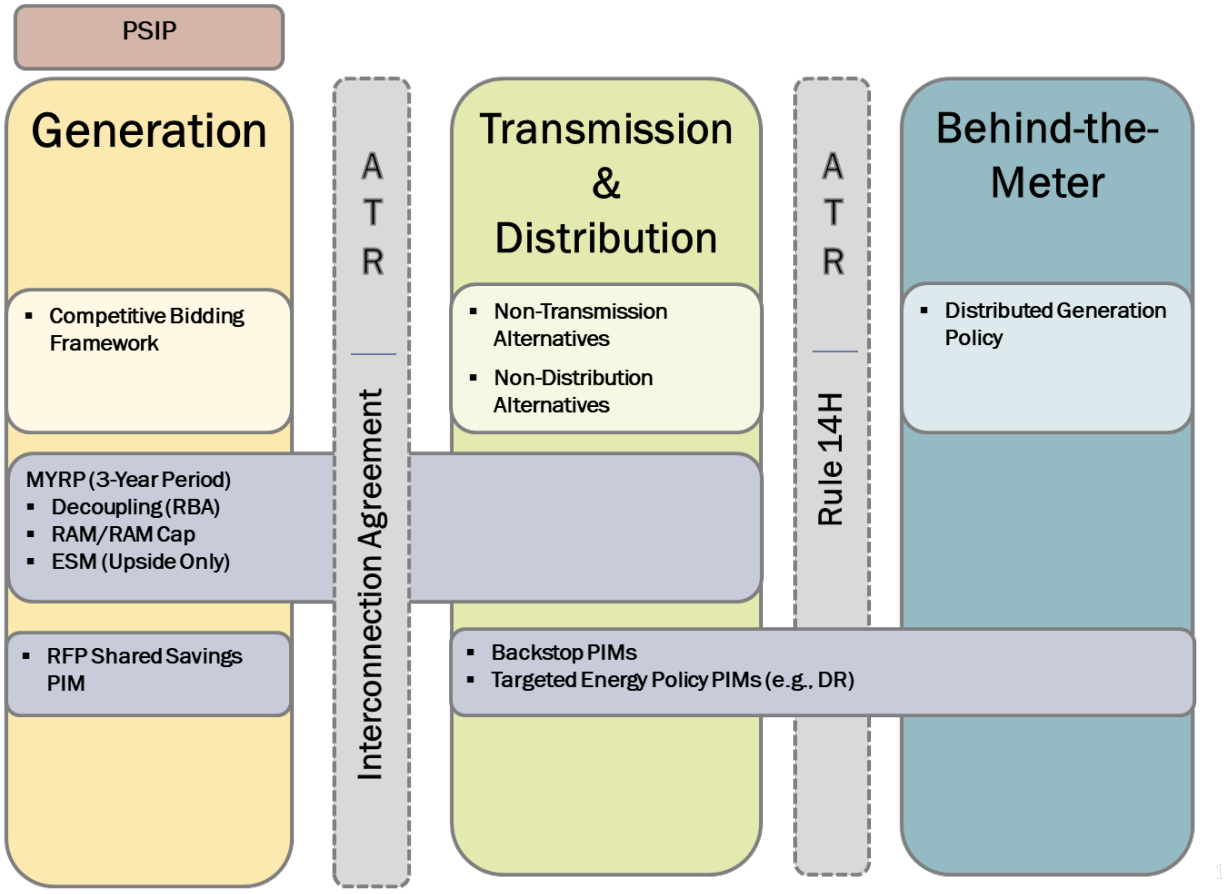
## The Broader Regulatory Landscape

As the Commission has observed through the course of the PBR proceeding, a well-designed PBR framework can strengthen incentives for utilities to improve performance across a wide range of initiatives.

That said, even a comprehensive PBR framework does not address all of the regulatory challenges inherent in Hawaii's energy transition. Rather, the Staff Framework offered in this Proposal is but one piece of the overall regulatory puzzle. This section explores the proposed PBR framework through a wider lens to examine its position in the larger regulatory landscape and unfolding energy transition. As described below, several regulatory activities will need to be aligned and harmonized over time in order to best achieve the state's energy goals.

Figure 1, below, offers a view as to how the various elements and activities fit together in the regulatory landscape today across the three segments of the industry value chain, as introduced in Staff Report #3.

**Figure 1. Existing Regulatory Landscape**



As shown above, the electricity system in Hawaii can be viewed to have three distinct segments: generation, transmission & distribution, and behind-the-meter. Each segment corresponds to a portion of the physical and transactional dimensions of the overall electricity system.

The **Generation** segment is composed of electric generating stations (both utility- and third-party owned) that make up the bulk power system. This segment may also include generation that is interconnected to the distribution system in-front-of the meter. Over time, the generation segment may increasingly include emergent technologies that are not strictly "generation" in the traditional sense, such as battery energy storage systems and synchronous condensers.

The **T&D** segment represents the cyber-physical infrastructure that serves as the electric network. This includes transmission lines, substations, the distribution system and metering technology – as well as the communications, sensing, measurement, and computing systems that work together to operate the power system.

The **BTM** segment includes the various distributed energy resources ("DERs") emerging at the grid edge, interconnected on the customer's side of the point of common coupling. These DERs include rooftop solar photovoltaics ("PV"), distributed battery storage systems, customer-sited EV charging infrastructure, energy efficiency measures and flexible/controllable loads.

When regulation was first applied to the electric industry, no categorical distinction was necessary regarding how these segments were regulated. Over time, however, it has been recognized that natural monopoly attributes apply differently to each segment, with corresponding changes incorporating some competitive and market mechanisms to specific segments. Given the distinctions between the characteristics of each segment, crafting regulatory approaches targeting each individual segment may yield a more cost-effective regulatory system that is better aligned with the public interest. Such a differentiated segmented approach is consistent with the evolution of regulation in Hawaii.

## Harmonization: Planning, Procurement, and the PBR Framework

The timing and calibration of a 5-year MRP cycle will likely need to be harmonized with power system planning and procurement cycles. This is particularly true given that the HECO Companies have outlined an Integrated Grid Planning ("IGP") approach, which proposes a fully integrated planning and procurement process.[190] The IGP approach "appraises the total needs of the system, considers all alternatives (from customers, independent providers and the utility), then selects the lowest cost/best fit solution(s) to produce an optimized portfolio to reliably and affordably operate the grid with the desired level of resilience."

[190]Docket No. 2018-0165, Instituting a Proceeding to Investigate Integrated Grid Planning, "Planning Hawaii's Grid for Future Generations: Integrated Grid Planning Workplan," filed December 14, 2018 ("IGP Workplan"), at 1.

The IGP process, as proposed, will culminate in a 5-year action plan and related applications for Commission approval.[191] An IGP action plan will likely have a material impact on system operations costs due to the nature and scale of new technologies deployed, which are partially predicated on achievement of greater efficiency. Overreliance on interim cost adjustment mechanisms, such as MPIR, to account for major investments included in a 5-year IGP action plan could result in a cumbersome regulatory process and dilute the cost reduction incentives integral to an MRP. Accordingly, MRP and IGP cycles will need to be aligned, such that an approved or accepted IGP plan informs the setting of base rates or target revenues for the subsequent MRP control period, which should improve regulatory efficiency. Such harmonization and calibration should help to ensure the IGP process is directly and contemporaneously translated into customer benefits through the revenue recovery process.

## Facilitating Development of a Platform Utility Model

As various Parties to this proceeding have stressed, while traditional core utility functions remain critical roles of the HECO Companies, technological developments and changing customer preferences are compelling the Companies to act more like a platform – to foster transactions and connections between producers and consumers of energy services. Indeed, the Commission has previously suggested the need for the HECO companies to evolve toward a service-based platform model with new functions as a network integrator and operator,[192] which would include a move toward the creation of efficient, cost-effective, accessible grid platforms for new services, and opportunities for adoption of new distributed technologies.[193] To that end, the Staff Framework offered in this Proposal suggests modifications and improvements to existing regulatory mechanisms that could remove some barriers to utility sector transformation and, to some degree, foster the emergence of robust, cost-effective, and self-sustaining markets for DER.

For any platform business model to function well and facilitate the types of transactions and connections that create value, customers and third-parties must trust and have assurance in the neutrality of the platform provider.[194] A variety of regulatory elements in place today can help foster the necessary market integrity to permit a utility platform model to develop. Such elements include, but are not limited to: (a) Affiliate Transaction Requirements ("ATR") to guard against unfair competition by the incumbent;[195] (b) Tariff Rule No. 14H to standardize and

[191] *See* IGP Workplan at 39.

[192] *See* Docket No. 2012-0036, Decision and Order No. 32052, filed April 28, 2014, Exhibit A (the Commission's "Inclinations"), at 13-14, 20; Docket No. 2015-0412, Decision and Order No. 35238, filed January 25, 2018, at 3-4.

[193] *See* Docket No. 2016-0087, Order No. 34281, filed January 4, 2017.

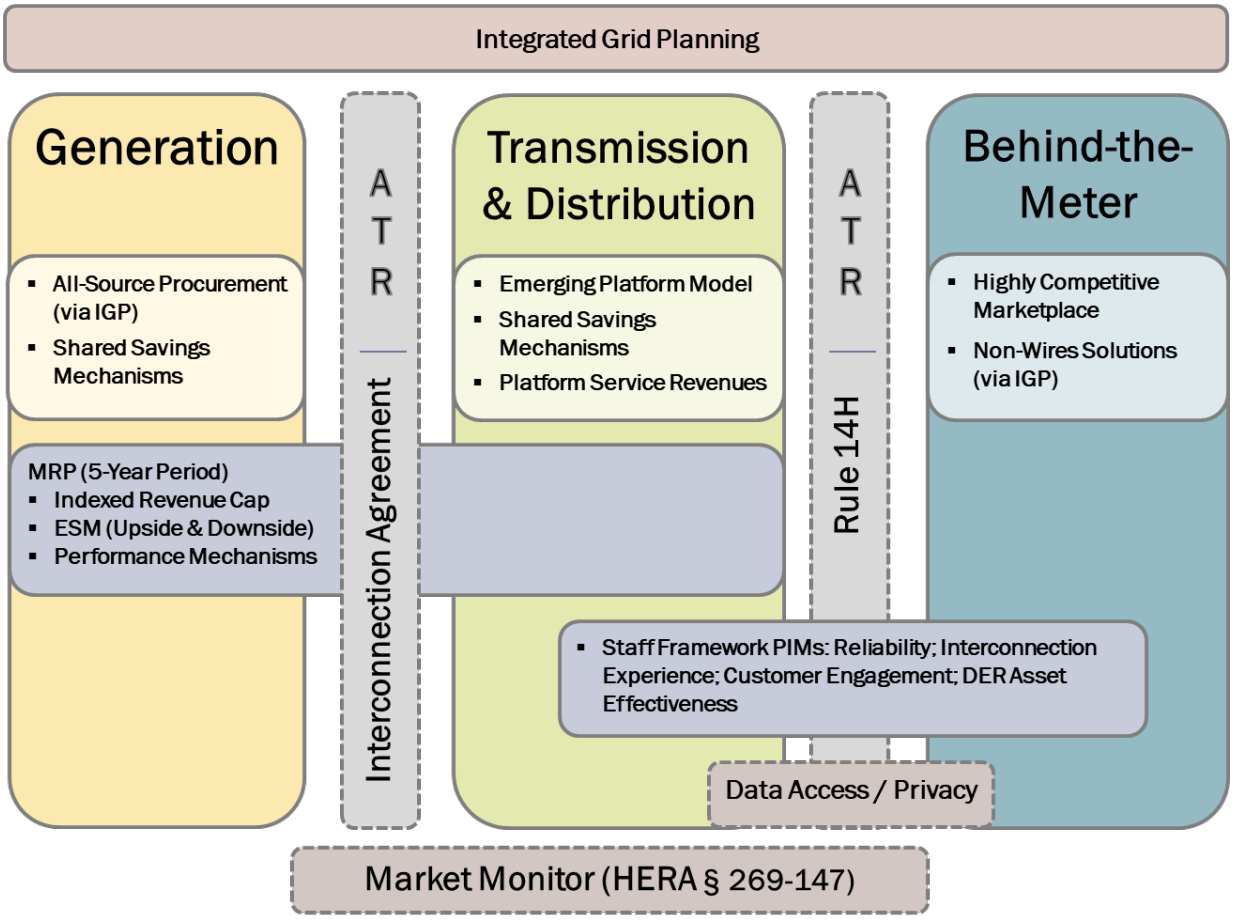
[194] *See* Geoffrey G. Parker, Marshall W. Van Alstyne, and Sangeet Paul Choudary, Platform Revolution: How Networked Markets are Transforming the Economy - and How to Make Them Work for You, W.W. Norton & Co., 2016, at 192-93.

[195] *See* Docket No. 2018-0065, Order No. 36112, filed January 24, 2019.

streamline network access for customers seeking to interconnect DER;[196] and (c) transparent data access and privacy guidelines to help animate distribution-level markets. Going forward, it may be advisable to enforce reliability standards and explore the creation of a market monitor, consistent with HRS § 269-147, which grants the Commission authority to establish a Hawaii Electric Reliability Administrator ("HERA").

Building on Figure 1, Figure 2 illustrates what a prospective regulatory landscape could look like as layered across the three segments of the electric power system. Figure XX incorporates several of the regulatory activities referenced above that could serve to support Hawaii's energy transition and catalyze the development of a platform utility model. However, many, if not all, of these regulatory activities would necessarily be developed outside of the more narrowly focused PBR proceeding, but nonetheless there is value in visualizing how each of these pieces may contribute to the whole going forward.

**Figure 2. Prospective Regulatory Landscape**




[196] *See* Rule No. 14, at Revised Sheet No. 34A-1 ("Rule 14H"), *available at* https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/14.pdf.