BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF HAWAII

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Performance-Based Regulation.	DOCKET NO. 2018-0088

ULUPONO INITIATIVE LLC'S BRIEF ON RE-BASING TARGET REVENUE

AND

CERTIFICATE OF SERVICE

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Ulupono Initiative LLC ("Ulupono"), by and through Murray R. Clay, its President, and its attorneys Schlack Ito, A Limited Liability Law Company, and pursuant to the Commission's Order No. 41179,[1] hereby respectfully submits its Brief on Re-Basing Target Revenue ("Brief"), as follows.

I. INTRODUCTION

Ulupono submits that the issue of re-basing the Companies'[2] Target Revenue in conjunction with the transition from the first multi-year rate plan ("MRP1") to the second MRP ("MRP2") presents a critically important opportunity to strengthen, protect, and advance the Performance-Based Regulation ("PBR") framework ("PBR Framework"). The PBR Framework has been implemented since 2021 and MRP1 is drawing to a close. During MRP1, the Framework has experienced challenges to successful implementation as well as opportunities for further growth and development as a leading innovative regulatory approach. As MRP2 comes into focus, the issue of whether and how to re-base Target Revenue has risen to the forefront of

[1] Order No. 41179 Establishing a Briefing Schedule for Determining Whether to Re-Base Revenues filed November 8, 2024 ("Order No. 41179"). This Brief is timely filed on or before the due date of December 5, 2024. *Id.* at 6.

[2] Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO"), and Maui Electric Company, Limited ("MECO") (collectively, "Hawaiian Electric" or "Companies").

PBR implementation concerns, necessitating careful review and analysis to navigate the dynamic regulatory environment.

In this context, Ulupono has continued its ongoing efforts as a stakeholder and docket party to evaluate and analyze key issues surrounding the re-basing of Target Revenue. In addition to filing submissions and participating in the Working Group process in a collaborative effort to work with the Commission and parties to develop clarity on this topic, Ulupono has engaged its consultant Roland Berger to assist with additional research and analyses as reflected in the report "PBR Renewal Recommendations" ("PBR Renewal Report"), attached as Exhibit A, which provides support for Ulupono's positions in this Brief.[3] It should be noted that the analyses in the PBR Renewal Report are primarily based upon data and information regarding HECO alone rather than all three of the Companies, and thus references to HECO in the PBR Renewal Report and this Brief are intended to refer solely to HECO, unless otherwise noted.

An important example of the results of Ulupono's further analyses supported by the PBR Renewal Report is the conclusion that in 2023 HECO's Return on Equity ("ROE") would have been 9.2% with two simple adjustments – which is reasonably close to its allowed ROE of 9.5%.[4]

With regard to the PBR Framework, Ulupono maintains that it can best be strengthened, protected and advanced by adhering to the following:

- First, Ulupono strongly recommends that for MRP2 no comprehensive re-basing is necessary except for a very limited re-basing in the form of a one

[3] Although for various reasons the results of the PBR Renewal Report were not available for review in the Working Group process, Ulupono remains open to further collaborative discussions on re-basing and related matters.
[4] PBR Renewal Report at 4. This ROE would be expected if the $5 million Consumer Dividend payment had not been in effect and the capital structure equity percentage was at the actual percentage, rather than the previously-approved 58%.

time true-up, for the first year of MRP2 only (and based on the latest year only of the completed results in MRP1), to adjust the utility's realized ROE up to its allowed ROE ("true-up"), and this true-up would eliminate the need for a rate case for MRP2;[5]

- Second, for future re-basing for MRP3 and beyond (i.e., excluding MRP2), consideration should be given to using a notional revenue adjustment ("notional revenue adjustment") methodology, as was adopted by the regulator in Alberta, Canada, which would adjust Target Revenue based on historical capital and operations and maintenance ("O&M") costs;[6] and
- Third, although a rate case should be avoided for a number of important reasons, including noncompliance with PBR statutory mandates,[7] if a rate case is deemed necessary for MRP2 then at a minimum it should be based on an historical test year and not a forward-looking test year, and Performance Incentive Mechanism ("PIM") rewards should be increased to up to 2% of ROE in conjunction with the rate case.

Each of these points is discussed in further detail below.

II. FOR MRP2, ULUPONO RECOMMENDS THE TRUE-UP ONLY AND NO RATE CASE IS NECESSARY

No re-basing is justified other than the true-up, and accordingly a rate case is not warranted. The PBR Renewal Report is based upon and incorporates publicly-available data and

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[5] *See* PBR Renewal Report at 4, 7, 12.

[6] *Id.* at 8-10.

[7] Under section 269-16.1, Hawaii Revised Statutes ("HRS"), "Performance incentive and penalty mechanisms," subsection (a), the Commission shall establish a PBR framework that "directly ties" the Companies' Target Revenue to performance metrics and "break[s] the direct link" between allowed Target Revenue and investment levels (collectively, "PBR statutory mandates"). A rate case is likely to not directly tie the Companies' Target Revenue to performance metrics and is accordingly unlikely to "break the direct link" between Target Revenue and investment levels.

information, including Federal Energy Regulatory Commission "Form 1 - Electric Utility Annual Report" for the Companies. Roland Berger's qualifications include its involvement as Ulupono's consultant in earlier phases of this proceeding, as well as extensive participation in the PBR Working Group process.[8]

The one time true-up, limited to the first year of MRP2, will ensure the Companies have adequate rates to cover their respective costs. It will also allow customers to share in efficiencies gained through MRP2. It should be noted that HECO's ROE deficit is not due to excessive spending on capital or increases in O&M spending during MRP1. HECO's rate base peaked in 2020 (in real dollars) and HECO subsequently cut capital expenditures.[9]

One reason for HECO's underperformance is that there is a mismatch between HECO's actual capital structure equity percentage, which is well above 60%, and the allowed equity structure of 58%. In addition, the audit give-back has put pressure on returns in the amount of approximately $5 million per year. In the absence of these two items – capital structure and the audit – HECO's ROE would have been 9.2% in 2023, which is close to the allowed ROE of 9.5%.[10]

In addition, the PBR Renewal Report describes a simplified methodology to complete the true-up and provides a spreadsheet illustrating the application of this methodology to HECO.[11] The results shown on the spreadsheet demonstrate that the true-up amount for HECO would be in the range of $15.2 million to $42.9 million.[12] Given that only the limited re-

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[8] As one notable example, the contributions of Roland Berger to this docket include development and sharing of an open access utility financial modeling tool referred to as the "Regulatory Innovation Simulation Tool." *See* Ulupono Initiative LLC's Phase 2 Reply Statement of Position filed Aug. 20, 2020 (Docket No. 2018-0088) at Exhibit D-1.

[9] *See* PBR Renewal Report at 4. Ulupono contends HECO's rate base peaked in 2020 and HECO subsequently cut capital expenditures as a result of implementation of the PBR Framework, further evidencing the beneficial impact of the PBR Framework.

[10] *See* PBR Renewal Report at 4.

[11] *See id.* at Attachment A.

[12] *See id.* at 15; Attachment A.

basing in the form of the true-up is necessary, it follows that there is no need for a rate case. This is especially true given the need to devote time and resources to Z Factor and EPRM proceedings focused on wildfire mitigation and resiliency measures.

III. FOR FUTURE RE-BASING IN MRP3 AND BEYOND, A NOTIONAL REVENUE ADJUSTMENT SHOULD BE CONSIDERED

A. For Future MRPs, a Notional Revenue Adjustment Is Recommended Over a Rate Case.

The Commission should consider using a notional revenue adjustment methodology not for MRP2 but for future re-basing for MRP3 and beyond. Under this methodology, re-basing to a new Target Revenue is achieved through a one-time adjustment based on representative capital and O&M amounts. These amounts are derived from historical values and would be converted to current year dollars. This methodology can be used with three to four year lookbacks, or it can use averages or minimums with regard to O&M figures.[13]

B. If a Notional Revenue Adjustment Is Used, Key Considerations Should be Taken Into Account.

1. A notional revenue adjustment proceeding would be supported by Alberta experience.

Ulupono proposes that this notional revenue adjustment methodology be based upon the methodology used in Alberta, Canada for the PBR proceeding regarding eight distribution utilities for the transition from the first to second PBR phase (as distinguished from the transition from the second to third PBR phase).[14] The PBR Renewal Report provides a detailed illustration of the application of this methodology, concluding that it "simply adjusts revenue requirements based on estimated changes to rate base and O&M during last MRP."[15]

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[13] *See id.* at 6.
[14] *See id.* at 8.
[15] *Id.* at 8.

The Alberta regulatory commission decided to use this notional revenue adjustment methodology for reasons relevant to potential future re-basing under the Hawaii PBR Framework. In essence, the commission in Alberta chose to use this methodology in part to counter the perverse incentives facing utilities which may cause them to favor over-forecasting Target Revenues and increasing costs for subsequent PBR terms. As the Alberta commission explained in its order adopting this methodology, a forward-looking test year may create incentives to over-forecast to the detriment of utility customers:

> 43. In the Commission's view, achieving these objectives requires balancing of the features of both proposed general approaches to rebasing, as each has its merits and disadvantages. EPCOR and the interveners pointed out that setting going-in rates in a COS proceeding based on forecast costs may create incentives to over-forecast, with the result that customers do not share in the benefits of productivity gains achieved by the distribution utilities in the current generation PBR plans. . . . .

The Alberta commission also observed that a rate case would be unlikely to reduce the regulatory burden, and may incentive the utility to inflate costs stating:

> 44. Additionally, the interveners stated in argument that because of information asymmetry, testing cost forecasts would require the same level of detail as in a traditional COS proceeding. As such, regulatory burden is unlikely to be reduced under this approach to rebasing.
>
> 45. Rebasing on actual results addresses these concerns to a large degree. However, some distribution utilities pointed out that rebasing based on forecast costs will reflect changing circumstances in the test year and thus may result in going-in rates better reflective of a reasonable opportunity to earn a fair rate of return. Nevertheless, the principal reason for not using 2017 actual costs is the incentives the distribution utilities have in the final year of current generation PBR to inflate their costs so as to increase going-in rates for the next generation PBR term. The Commission is also concerned that using the 2017 actual results, which would not be available until May 2018, would not allow for implementation of the next generation PBR rates on January 1, 2018.

Based on these concerns, the Alberta commission rejected using a forward-looking test year in a Cost of Service Regulation ("COSR") rate case, and instead opted for the same type of notional revenue adjustment, stating:

> 46. Having considered the evidence and argument of the parties and after applying its judgement in light of the objectives and purposes of rebasing as described earlier in this section, the Commission <u>does not consider it necessary or desirable to employ a 2018 forecast COS year in order to set going-in rates</u>. <u>Rather, the Commission has determined that it will set going-in rates on the basis of a notional 2017 revenue requirement using actual costs experienced during the current generation PBR term</u> for each distribution utility with any necessary adjustments to reflect individual distribution utility anomalies. . . . .

The concerns and objectives expressed by the Alberta commission may apply with equal force to the issues regarding future re-basing in the Hawaii MRP3 and beyond. As in Alberta, the same perverse incentives – over-forecasting revenues and inflating costs – may be present and if so would be equally capable of adversely impacting Hawaii's PBR Framework. Information asymmetry is likewise capable of maintaining or increasing, rather than reducing, the regulatory burden imposed on the Commission and stakeholder parties. In short, the same reasons found for rejecting a COSR rate case in favor of a notational revenue adjustment in Alberta lend strong support to the consideration of this approach for future re-basing in MRP3 and beyond.[16]

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[16] *See* Alberta Utilities Commission, Errata to Decision 20414-D01-2016, "2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities" (Feb. 6, 2017) at 10-11 (emphasis added); *see also* PBR Renewal Report at 9. It is noted that for the transition from the second to the third PBR phase a COSR rate case was utilized based on circumstances that differ from the Companies' present situation. Specifically, the Alberta utilities were overearning their allowed ROE by over 180 basis points and the consumer advocate sought to have customers share in the savings and efficiencies gained. *See* Alberta Utilities Commission, Decision and Order No. 27388 (Oct. 4, 2023) at 8. By contrast, HECO is not over-earning and is instead under-earning by a small amount.

2. Rate design can be done on a revenue neutral basis.

Ulupono contends that cost allocation and rate design can be done separately on a revenue neutral basis and do not need to be linked to re-basing. Using a revenue neutral approach would eliminate the need for broader rate design efforts which would fall under a COSR rate case, and promote administrative efficiencies.

3. The true-up and any future notional revenue adjustment would comply with applicable laws.

The one time true-up as well as a future notional revenue adjustment proceeding can both be undertaken in a manner that complies with applicable legal authorities and requirements. Both are likely to comply with the PBR statutory mandates which require a PBR framework that "directly ties" the Companies' Target Revenue to performance metrics and "break[s] the direct link" between allowed Target Revenue and investment levels. Ulupono contends that the MRP2 true-up (and also a future MRP notional revenue adjustment) breaks the direct link, but only significantly increasing the value of the PIMs will "directly tie" with performance metrics in a meaningful way. A rate case is likely to establish or reestablish and reinforce a direct link – rather than break the direct link – between Target Revenue and investment levels.

The true-up, as well as a potential future notional revenue adjustment, are also not required to comply with HRS § 269-16, "Regulation of utility rates; ratemaking procedures." The requirements of HRS § 269-16 do not apply because they are supplanted by HRS § 269-16.1 as long as the Companies are regulated pursuant to the PBR Framework rather than through COSR, particularly a COSR rate case. In D&O 37507,[17] the Commission stated that its

[17] Decision and Order No. 37507 filed Dec. 23, 2020 ("D&O 37507").

"preference is to not return to a general COSR rate case"[18] and that there should instead be a "comprehensive review of the PBR Framework[.]"[19] Given that HRS § 269-16 applies to rate cases, and the Commission has previously stated its preference for a comprehensive review rather than a rate case, it is reasonable to conclude that the rate case requirements of HRS § 269-16 do not apply to the true-up or a future notional revenue adjustment. Consistent with the foregoing, HRS § 269-16.1 states that the PBR Framework PIMs and penalties "shall apply to the regulation of electric utility rates under section 269-16."[20] This further supports the conclusion the requirements of HRS § 269-16 do not apply to a non-rate case review of rates under the PBR Framework, such as through a notional revenue adjustment.

4. The true-up (as well as any future notional revenue adjustment proceeding) would be completed more quickly than a rate case.

The true-up would be fast and simple. Similarly, a future notional revenue adjustment process would require less time as compared to a rate case. In addition, it is unclear if a rate case could be timely completed before MRP2 commences. To comply with time constraints, it may be necessary or advisable for Target Revenue to be re-based not only before the commencement of MRP2, but also during a relatively early phase of this PBR review. The true-up would easily satisfy that objective.

5. Any future notional revenue adjustment proceeding should occur in a separately-docketed proceeding with an intervention period.

For future MRPs, if a notional revenue adjustment proceeding or a rate case proceeding is deemed necessary for MRP3 and other subsequent MRPs, Ulupono supports a separately docket proceeding with an intervention period. It is well established that the

[18] D&O 37507 at 209.
[19] *Id.* at 34.
[20] *Id.* (emphasis added).

Commission's Rules of Practice and Procedure contemplate intervention and participation in both investigatory proceedings and rate cases, as well as other proceedings based on other application filings.[21] Establishing an intervention period for a re-basing proceeding would also be consistent with relevant precedent.[22] Establishing an intervention period would in addition be broadly consistent with the Commission's stated interest in promoting transparency and equity in the energy equity investigative proceeding. For example, the Commission opened Docket No. 2022-0250 to "investigate how to better integrate equity and justice considerations across Commission proceedings and the Commission's work more broadly, including in its role overseeing and regulating the functions of public utilities."[23] Indeed, in that proceeding the Commission has indicated a motion to intervene or participate is not necessary in order to provide input.[24]

IV. THE COMMISSION SHOULD REJECT PROPOSALS FOR A RATE CASE TO RE-BASE TARGET REVENUE FOR MRP2

A. A Rate Case Is Not Warranted for a Range of Important Reasons.

A central theme of this Brief is that a rate case would be the least desirable potential option with regard to the issue of whether and how to re-base Target Revenue for MRP2. As explained above, the one time true-up is all that is needed for MRP2, and for MRP3 and beyond a notional revenue adjustment should be considered. The following provides

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[21] *See* Hawaii Administrative Rules ("HAR") § 11-601-55 (requirements for party to make an application to intervene); HAR § 11-601-56 (requirements for party to make an application to participate); HAR § 16-601-57(1) (time to file to intervene or participate in rate case); HAR § 16-601-57(2) (time to file for issuance or transfer of certificate of public convenience and necessity); HAR § 16-601-57(3) (time to file for other proceedings).
[22] *See, e.g.,* Order No. 35411 Instituting a Proceeding to Investigate Performance-Based Regulation filed April 18, 2018 (Docket No. 2018-0088) at 57-60 (authoring motions to intervene or participate).
[23] Order No. 38759 Instituting a Proceeding to Investigate Energy Equity filed Dec. 13, 2022 (Docket No. 2022-0250) ("Order No. 38759") at 1.
[24] *Id.* at 17-19.

additional detailed support for the conclusion that a rate case should not be utilized for MRP2, and indeed should be avoided for several important reasons.

1. A rate case is not warranted for the reasons identified in the PBR Renewal Report.

A rate case is not necessary for all of the reasons identified in the PBR Renewal Report. Broadly speaking, the challenging issues confronting the Companies would be more efficiently and effectively addressed outside of any re-basing process. In particular, a rate case would forfeit administrative efficiency. It cannot be meaningfully disputed that a rate case would be costly, burdensome and inefficient, especially relative to the proposed true-up or a future MRP notional revenue adjustment.

Further, efforts to respond to the Maui wildfires, including additional wildfire mitigation and climate resiliency measures, can be addressed through a Z Factor proceeding or through other narrowly tailored application-driven docketed proceedings. Additional resiliency expenses may also be able to use the Exceptional Project Recovery Mechanism ("EPRM") to recover such costs. Adjustments in depreciation can also be added to Target Revenue with no impact to ROE, and this should occur outside of any re-basing process.[25]

2. A rate case would not ensure capacity for PIM reward increases.

Under the PBR Framework, PIM incentives must remain capable of financially incentivizing the Companies to achieve performance objectives. A rate case is likely to substitute or supplant PIM rewards with Target Revenue adjudicated through the rate case proceeding. PIM rewards are currently not sufficient to meaningfully incentivize the Companies

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[25] PBR Renewal Report at 4; *see also id.* at 5 ("Time and expense is better served with addressing wildfire issue than litigating a rate case."); *id.* at 11 ("Overall, traditional cost of service is the worst of the three options, especially if done on a forecast basis"); *id.* at 13 ("wildfire cost recovery should be dealt with outside of a rate case"); *id.* at 16 ("Time and energy can be better spent on the large wildfire recovery issue outside of the rebasing proceeding.").

to achieve performance objectives and have been a comparatively miniscule portion of utility revenues. Thus, as a general matter, Ulupono recommends that PIM rewards be increased to provide a meaningful incentive to align with the directives in HRS § 269-16.1(a). To ensure the PBR Framework remains appropriately focused on incentivizing performance, a combined earning potential of approximately 2% of ROE (approximately $60 million in pre-tax revenues for HECO only) should be possible through increased rewards for PIMs. Absent this, nearly all revenues will be based largely on cost of service – simply a reward for spending – and not a reward for performance.

Ulupono understands this proceeding will include additional phases to review PIM reward increases and related matters.[26] For purposes of this Brief, however, Ulupono submits that it is critically important to consider increases in PIM rewards given the fundamental role they play in driving utility performance under the PBR Framework. Accordingly, a paramount concern is to avoid rate case proceeding that that hobbles or even forecloses meaningful financial incentives – thereby jeopardizing the future success of PBR in Hawaii.

3. A rate case would not comport with Commission prior guidance in D&O 37507 or prior party filings.

Prior statements from the Commission and parties expressing concern or opposition to a rate case for MRP2 remain relevant to the extent the underling rationale is unchanged. Although such statements may not be binding on the Commission at this time, they may be persuasive given the nature of the regulatory process and the extent to which the issues remain unresolved.

[26] *See, e.g.,* Order No. 40852 at 5 (Phase 5 outcome includes potential modifications to PBR mechanisms).

a. Commission.

With regard to the Commission, Ulupono submits that a decision to require a rate case would unnecessarily and unjustifiably depart from the original insight and guidance reflected in D&O 37507. Although the true-up would comply with the Commission's guidance – including in D&O 37507 – a rate case would not.

D&O 37507 is replete with language supporting the conclusion that a rate case is to be avoided with regard to re-basing for MRP2. For example, D&O 37507 states: "It is expected that the post-MRP will consist of some refined version of the PBR Framework, <u>rather than a return to traditional COSR</u>."[27] D&O 37507 also affirms the Commission does not envision a return to COSR, stating:

> Fourth, during the fourth year of the MRP, the Commission will conduct a comprehensive review of the PBR Framework to determine if the Framework should continue or be modified in any way. Details will be provided nearer to the fourth year of the MRP, and for now, focus should be on gaining experience with the PBR Framework. Although anticipating some modifications to the PBR Framework may be appropriate, <u>the Commission does not envision returning to COSR after the initial MRP</u>.[28]

Further, D&O 37507 frames the key issue as "<u>whether a return, in part or in full, to traditional COSR</u> is appropriate to <u>'rebase'</u> the Companies' rates."[29] The order states that the Commission's "<u>preference is to not return to a COSR general rate case</u>."[30] The order further states:

> Rather than worry about what will happen at the end of the MRP, the Companies should focus on how to thrive under the PBR Framework, regardless of the ultimate duration of the MRP. <u>The expectation should not be that the PBR Framework is an experiment that will be abandoned in favor of a return to COSR</u> at

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[27] *Id.*
[28] *Id.* at 34.
[29] *Id.* at 207 (emphasis added).
[30] *Id.* at 209 (emphasis added).

> the first challenge – rather, the expectation is that the Commission will work with the Companies and stakeholders to modify the PBR Framework over time to support its continued longevity and success.[31]

The Commission has also stated: "In the fourth year of the MRP, the Commission will comprehensively review the PBR Framework to determine if any modifications or revisions are appropriate. It is expected that the post-MRP will consist of some refined version of the PBR Framework, rather than a return to traditional COSR."[32]

In summary, D&O 37507 – which is foundational to establishment of the PBR Framework – plainly confirms the Commission's preference at that time to "not return to a COSR general rate case." Thus, a decision at this juncture to require a rate case would unnecessarily and unjustifiably depart from the Commission's original insight and guidance at the time the PBR Framework was established through D&O 37507.

b. Consumer Advocate.

It should be noted that the preference or necessity to avoid reverting to a rate case was also expressed by the Consumer Advocate prior to issuance of D&O 37507. For example, in its Phase 2 Statement of Position the Consumer Advocate affirmed in the Executive Summary that the "utilities file proposed revisions to MRP/PIM terms in fourth year based on adjusted actual earnings in preceding calendar year(s); no return to COSR."[33] The Consumer Advocate also cited to HRS § 269-16.1 with regard to the mandate to "break the direct link" between allowed revenues and investment levels, and identified such "linkages" to include "not reverting to traditional rate case regulation at the end of the initial control period[.]"[34]

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31 *Id.* at 210 (emphasis added).
32 Hawaii Public Utilities Commission, "Hawaii PUC Drives Transformation Of Hawaiian Electric With New Performance-Based Regulation" *available at* https://puc.hawaii.gov/energy/pbr/.
33 Division of Consumer Advocacy's Phase 2 Initial Statement of Position filed June 18, 2020 ("CA Phase 2 SOP") at 16 (emphasis added).
34 *Id.* at 3 (emphasis added).

The Consumer Advocate further reiterated its position against an end-of-MRP rate case in section III.E of its Statement of Position, "MRP Control Period Termination Procedures."[35] In that discussion, the Consumer Advocate continued to recommend that there be no return to "traditional, forecasted test year rate cases" at the end of the MRP.[36] Return to a COSR rate case would be "inherently problematic" due to the "perverse incentive" to defer costs; the dilution of cost control incentives; the gaming of PIMs; the failure to mitigate the capital expenditure bias; the significant and burdensome resource commitments, which could delay updates to the PBR Framework; and the need to "break the direct link" pursuant to HRS § 269-16.1.[37]

c. Ulupono.

For its part, Ulupono likewise opposed reverting to a rate case, explaining in its Statement of Position as follows:

> Similar to its continued support for a five-year MRP, Ulupono also supports and views as foundational the establishment of a PBR framework that does not contemplate or provide for a traditional rate case type of proceeding based on cost of service regulation ("COSR") principles ("rate case") upon the conclusion of the initial or any subsequent five-year MRP period.
>
> Ulupono's position is consistent with the Commission's recent order terminating Hawaiian Electric's mandatory triennial rate case cycle. In Order No. 37119, the Commission explained that the PBR framework under consideration in this proceeding contemplates replacement of the mandatory triennial rate case cycle with an ARA combined with a five-year MRP. The rationale underlying termination of the rate case cycle in Order No. 37119 is consistent with Ulupono's position that the PBR framework in this proceeding should effectively terminate recourse to rate cases upon the conclusion of a five-year MRP period.

[35] *Id.* at 44-51 (emphasis added).
[36] *Id.* at 44 (emphasis added).
[37] *Id.* at 45-46 (emphasis added).

> Ulupono has set forth its position on this issue, which is consistent with Order No. 37119, in its prior submissions. Importantly, implementation of a robust ESM, such as the ESM supported by Ulupono in this proceeding, should safeguard Hawaiian Electric's credit rating and general financial integrity. The ESM (in combination with a five-year MRP, the ARA taking effect on January 1, and PBR Review in place of rate cases) should also afford Hawaiian Electric added flexibility to avoid regulatory lag and greatly reduce time and resources devoted to the regulatory process. Including a future traditional rate case in PBR is also very likely to result in Hawaiian Electric focusing on higher cost initiatives to justify higher revenues, and to otherwise not take advantage of cost-saving measures during the MRP period, contrary to PBR cost control incentives.
>
> In addition, a rate case also could result in utility expectations and actions during the MRP which may be contrary to or undermine successful PBR implementation and fail to break the direct link between revenues and capital investments, as is required by statute. As explained in Ulupono's FPU, reverting to a rate case would not be consistent with the fundamental purpose of PBR, which is to align Hawaiian Electric's incentives to achieve energy policy objectives. These objections to establishing a PBR framework that provides for rate cases address fundamental concerns, reflecting the ability of rate cases to hamper successful PBR implementation. Accordingly, Ulupono's position on this issue remains that the PBR framework should not incorporate or allow for rate cases and Ulupono's PBR mechanism proposals are premised on that conclusion.[38]

Ulupono submits these observations and conclusions from its prior submission apply with equal force to the Commission decision-making on re-basing at this time, and continue to support an outcome that does not include a COSR rate case.

B. If a Rate Case Is Required, Key Considerations Should be Taken Into Account.

In the event a rate case is ultimately used for re-basing Target Revenue for MRP2, the following key considerations and requirements should be taken into account.

[38] Ulupono Initiative LLC's Initial Statement of Position filed June 18, 2020 at 9-11 (emphases added) (citations omitted).

1. A forward-looking test year should not be used.

As explained above, a forward-looking test year should be avoided and only an historical test year should be permitted for any rate case used to set Target Revenue for MRP2. This is primarily due to the risks of over-forecasting, inflated costs and gaming. Also, an historic test year, beyond these benefits, would help to preserve any success in controlling costs during the previous MRP by rebasing from costs expended and investments made while under the PBR incentives (i.e., increases from the Annual Revenue Adjustment mechanism). A forecasted future test year, however, would not be based at all under a period of time that had such cost control incentives in place.

2. The PBR Working Group process should be continued to develop an acceptable re-basing methodology that forecloses a potential future rate case for MRP3 and beyond.

For all of the above reasons, Ulupono strongly supports Commission approval of the true-up and rejection of any proposals for a rate case. Ulupono further proposes that the Commission extend the current PBR review working group process for the purpose of continuing to work toward a PBR re-basing mechanism – such as the proposed notional revenue adjustment mechanism discussed above – that achieves the desired objectives without recourse to rate case proceedings for MRP3 and subsequent MRPs.

V. CONCISE RESPONSE TO ORDER NO. 41179

Order No. 41179 identifies specific issues to be briefed and for convenience a concise response to each issue, based on the foregoing, is provided below.

1. Should Hawaiian Electric's Target Revenue be <u>re-based ahead of MRP2</u>?

The Companies' Target Revenue for MRP2 should be re-based only with regard to the true-up. Future re-basing in MRP3 and beyond should consider a notional revenue adjustment methodology. A rate case is not warranted.

- *What means, method, or metric should the Commission use to determine whether to re-base Target Revenue for MRP2?*

The Companies' Target Revenue for MRP2 should be re-based only with regard to the true-up. Future re-basing in MRP3 and beyond should consider a notional revenue adjustment methodology. A rate case is not warranted.

- *Is this means, method, or metric unique to the present situation (i.e. transitioning Hawaiian Electric from MRP1 to MRP2) or should it be used to assess whether to re-base Target Revenue as part of every MRP cycle?*[39]

Future re-basing in MRP3 and beyond should consider a notional revenue adjustment methodology. A rate case is not warranted.

2. If Hawaiian Electric's Revenue should be re-based, by what method and process should this re-basing be effectuated?

The Companies' Target Revenue for MRP2 should be re-based only with regard to the true-up. Future re-basing in MRP3 and beyond should consider a notional revenue adjustment methodology. A rate case is not warranted.

If re-basing of Target Revenue for MRP2 is to occur, regarding your proposed method and process:

- *What are the advantages and disadvantages of your proposal compared to a general rate case?*

The advantages and disadvantages of the true-up as compared to a rate case are as discussed above and in the PBR Renewal Report, and include but are not limited to significantly greater administrative efficiency (i.e., less time and cost for the Commission and all

[39] *Id.* at 4-5 (emphasis added).

stakeholders), no forecasting uncertainty, better understanding of actual results, preservation of the results of past cost control, and the removal of any opportunity for gaming of forecasts.

- *What is a <u>timeframe for completing</u> re-basing of Target Revenue under your proposal?*

The timeframe for completing the re-basing of Target Revenue using the true-up is expected to be very short and would require significantly less time than a rate case.

- *Should this proposed method and process occur in this docket or be addressed as a <u>separately docketed proceeding</u>?*

For re-basing with the true-up, there is no need for a separately-docketed proceeding and it can occur in this docket. For a rate case, a separately-docketed proceeding would be advisable.

- *Should, and if so, how, opportunities be permitted for entities who are not currently part of this docket to seek <u>intervention or participation</u> in the re-basing process?*

For re-basing with the true-up, there is no need for an intervention period. For a rate case, an intervention period would be advisable.

- *Which, if any, <u>legal authorities governing a general rate case</u> are applicable to your proposal (e.g., HRS § 269-16, HAR §§ 16-601-85, et seq.), and if so, how does your proposal comport with any such legal requirements?*

The true-up can be undertaken in a manner that complies with applicable legal authorities and requirements, including HRS § 269-16.1. The true-up is not required to comply with HRS § 269-16. A rate case is unlikely to comply with HRS § 269-16.1.

- *Is your proposed method and process to re-base Target Revenue intended specifically to facilitate Hawaiian Electric's transition from MRP1 to MRP2 or intended to be considered for <u>adoption as a part of every MRP cycle</u>?*

Future re-basing in MRP3 and beyond should consider a notional revenue adjustment methodology. A rate case is not warranted. The one time true-up is proposed for MRP2 only.

- *Does, and if so, how, your proposal address cost trackers and other revenue mechanisms currently not incorporated into Target Revenue (e.g., regulatory accounts, pension and OPEB trackers, other revenues not generated from the sale of electricity, potentially new depreciation and amortization rates)?*

The true-up does not implicate or affect cost trackers.

- *Should the allocation of Target Revenue among customer classes be included as part of the re-basing proceeding and, if so, how?*[40]

The true-up does not implicate or affect the allocation of Target Revenue among customer classes.

VI. CONCLUSION

For all of the foregoing reasons, Ulupono respectfully requests the Commission to issue an order on Target Revenue re-basing consistent with the foregoing discussion in this Brief, and to grant any further relief the Commission deems just and proper.

DATED: Honolulu, Hawaii, December 5, 2024.

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[40] Order No. 41179 at 5-6 (emphasis added).

PBR Renewal Recommendations

Rebasing analysis

December 5, 2024

EXHIBIT A

Contents

EXHIBIT A

A. Rebasing recommendation

EXHIBIT A

We recommend a one-time true-up for this MRP rebasing but other options should be considered going forward

- **We recommend rebasing** which would temporarily re-attach the link between costs and revenues. This ensures utilities have adequate rates to cover their costs and allows customers to share in efficiencies gained through the rebasing period

- Recommended rebasing options limited to the start of the new PBR plan are, in order of preference:
- **One time true-up** to adjust utility's realized ROE up to the allowed ROE
- **Notional revenue adjustment** – adjust revenue requirements based on historical capital and O&M costs
- **Cost of service rate case** with historic test year

- A comparison of options leads us to believe a **one-time equity true-up is the best option** for this rebasing period

- HECO's **ROE deficit is not due to excessive capital spend or O&M expenses during the last MRP period**
  – HECO's rate base peaked (in real terms) in 2020 as the utility cut capital expenditures since 2020[1] showing that the plan worked as intended
  – There have been limited shifts in O&M costs

- Two key reasons behind HECO's underperformance are:
  – **HECO hasn't maintained their allowed capital structure** – with equity above 60% when the allowed per the settlement of their last rate case is 58%
  – **The audit give back** has put pressure on returns at nearly USD 5 m per year
- Without these two items, **HECO's ROE would have been 9.2% in 2023, close to the allowed ROE of 9.5%**[2]

- The **main issues that the broader organization are facing are better resolved outside of the rebasing process**:
  – Maui wildfires have a separate proceeding and can utilize the Z factor mechanism
  – Additional resiliency expenses can utilize the EPRM for recovery
  – Adjustments in depreciation can be added to revenue requirements, with no impact to returns on equity and should be outside of the rebasing process

1) See slide 13; 2) See Attachment B for calculations

EXHIBIT A

We can utilize a set of principles to judge rebasing options – the importance of these principles may vary with the circumstances of the time and the utility

Principles for evaluating rebasing options

Principle	Description
Administrative Efficiency	• Be easy to understand, implement • Reduce the regulatory burden over time & enhance overall administrative efficiency • Commission, CA and utility time should be focused on advancing policy priorities
Incentives for Cost Control & Innovation	• Should reward cost control and innovation • Should minimize gaming of the system, for instance by the timing of capital expenditures
Performance Based	• Create the same efficiency incentives as those experienced in a competitive market while maintaining service quality • Encourage the expanding opportunities of customer choice and participation in appropriate aspects of utility system functions • Contribute to state policy objectives
Compliance with Act 5	• Establish performance incentives and penalty mechanisms that tie directly to an electric utility's revenues • Break the direct link between allowed revenues and investment levels
Fairness	• Allow sharing of PBR benefits between customers and the regulated companies • Maintain the financial integrity of the utility, with access to low-cost capital, to provide safe and reliable service • Be based on verifiable data and results • Be predictable and apply in a similar manner if the utility is over or under earning

Time and expense is better served with addressing wildfire issue than litigating a business-as-usual rate case

Wildfire situation heightens financial integrity issue which can be addressed in a Z factor proceeding and resiliency docket

EXHIBIT A

There are three general options for rebasing to consider in the current circumstances, listed from most preferred to least preferred to the right

Rebasing Options

A One-time true-up

Address under or over-earning with one year's adjustment to the authorized ROE

- Year must be completed and calculations based on actual results
- Ideally should not be a predicted action
- Helpful to address **structural financial issues** from continuing in next PBR plan
- Can be done at either
  - Allowed equity percentage (more favorable to the ratepayer)
  - Current equity percentage (more favorable to the utility)

B Notional Revenue Requirement

Rebase to new revenue requirement with a one-time adjustment based on representative capital and O&M amounts derived from historical values, converted to current year dollars

- Can be done with either 3 to 4 year look backs
- Can look at averages or minimums

C Formal Cost of Service

Conduct a formal cost of service proceeding to examine costs, allocations, rate design, and other issues

Can be done either

- With a historical test year
- With a forecasted test year

Historical test years are not subject to forecast errors and incentives for gaming

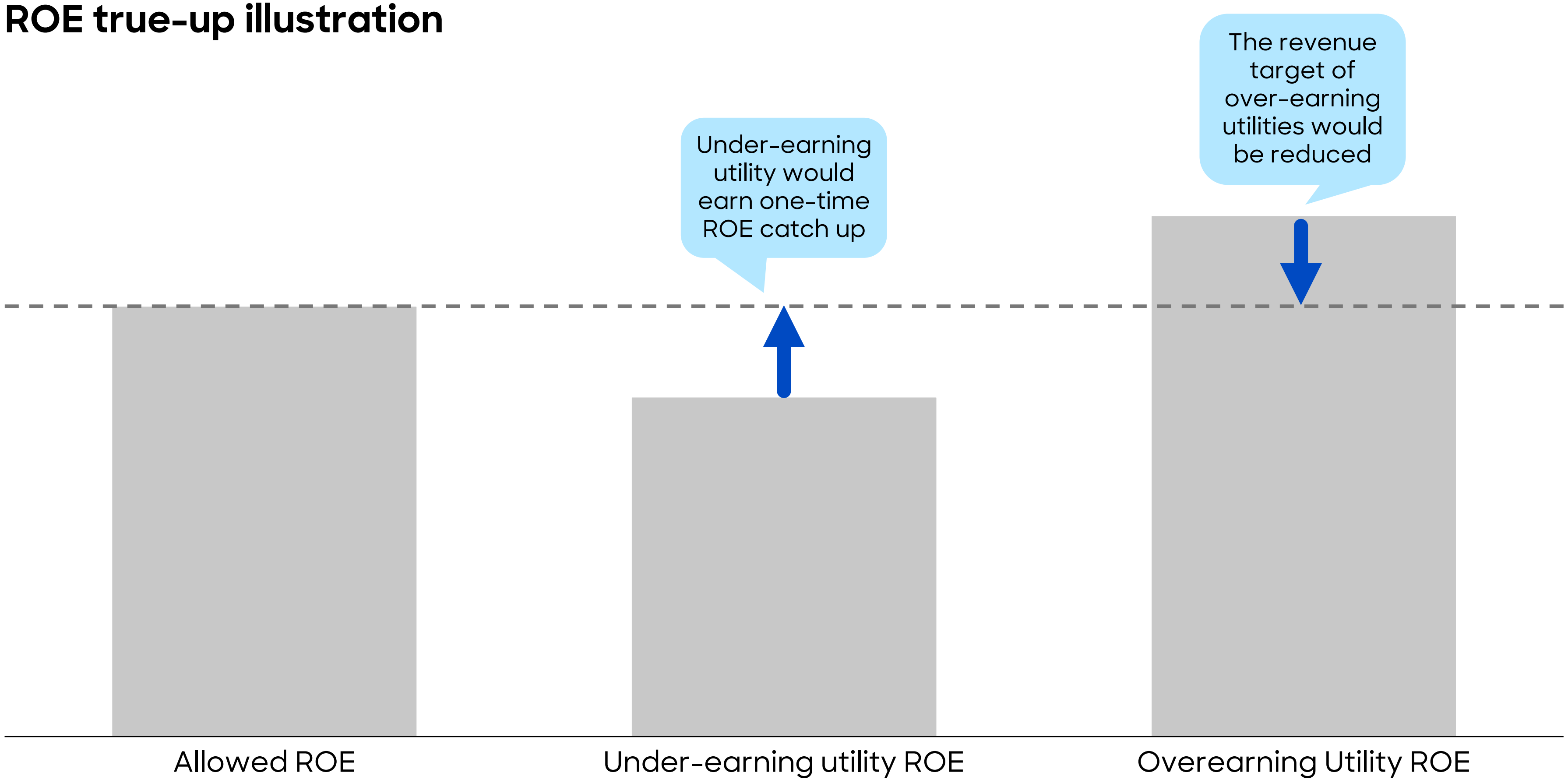
EXHIBIT A

Ⓐ Rebasing Option: One time true-up

The simplest rebasing option is the one-time true-up to bring ROE back up or down to the allowed rate, allowing time to be spent on more urgent priorities

Rebasing Option A: One Time True-Up

ROE true-up illustration



Simplified methodology

- Calculate earnings gap to allowed ROE
- Convert to pre-tax dollars
- Add amount to the target revenues in the first year of the new MRP, inflated to that year's dollar value
- See Attachment A for example of methodology

EXHIBIT A

Alberta used a notional revenue requirement method rebased from its first-generation PBR plan to its second-generation PBR plan

Rebasing Option B: Notional Revenue Requirement – based on Alberta PBR1 to PBR2 transition

Illustrative methodology

Year 1 | Year 2 | Year 3 | Year 4

Calculate Average O&M
for costs subject to I-X PBR methodology*
(variation: minimum of costs, trended costs)

→ Use representative O& M figures →

For capital outside of EPRM/MPIR/Z-factor:

Calculate Average Additions for last known 4 years

Calculate Average Retirements for last known 4 years

Calculate Average Cost of removal for last known 4 years

Determine a "typical" change in rate base due to "typical" net plant change →

Add two years' worth of "typical" rate base charges to the actual rate base in Year 4

Year 4 Actual Rate Base*

Year 5 Derived Rate Base*

Year 1 (new plan) Derived Forecast Rate Base*

*All converted with inflation (I-X) factors to Year 1 of new plan dollars

→ Use notional derived rate base →

Keep capital requirements (ROE, Debt cost, equity layer) the same as last plan →

Notional Revenue Requirements
Year 1 of new plan

O&M

+

(Rate base

×

Return on Rate Base)

This methodology simply adjusts revenue requirements based on estimated changes to rate base and O&M during last MRP

EXHIBIT A

Source: Alberta Decision 20414-D01-2016 (Errata), note this is a different methodology from the rebasing from PBR2 to PBR3 in which the consumer advocates were asking to share more in the resulting savings and efficiencies (Decision 27388-D01-2023)

Emphasis added

Alberta decided to use a notional revenue requirement to address perverse incentives to over-forecast and increase costs for the next PBR term

Alberta Decision 20414-D01-2016 (Errata)

43. In the Commission's view, achieving these objectives requires balancing of the features of both proposed general approaches to rebasing, as each has its merits and disadvantages. EPCOR and the interveners pointed out ***that setting going-in rates in a COS proceeding based on forecast costs may create incentives to over-forecast***, with the result that customers do not share in the benefits of productivity gains achieved by the distribution utilities in the current generation PBR plans

44. Additionally, the interveners stated in argument that because of ***information asymmetry***, testing cost forecasts would require the same level of detail as in a traditional COS proceeding. As such, regulatory burden is unlikely to be reduced under this approach to rebasing.

45. Rebasing on actual results addresses these concerns to a large degree. However, some distribution utilities pointed out that rebasing based on forecast costs will reflect changing circumstances in the test year and thus may result in going-in rates better reflective of a reasonable opportunity to earn a fair rate of return. Nevertheless, the principal reason for not using 2017 actual costs is ***the incentives the distribution utilities have in the final year of current generation PBR to inflate their costs so as to increase going-in rates for the next generation PBR term***. The Commission is also concerned that using the 2017 actual results, which would not be available until May 2018, would not allow for implementation of the next generation PBR rates on January 1, 2018.

46. Having considered the evidence and argument of the parties and after applying its judgement in light of the objectives and purposes of rebasing as described earlier in this section, the Commission does not consider it necessary or desirable to employ a 2018 forecast COS year in order to set going-in rates. Rather, the Commission has determined that it will set going-in rates on the basis of a notional 2017 revenue requirement using actual costs experienced during the current generation PBR term for each distribution utility with any necessary adjustments to reflect individual distribution utility anomalies.

EXHIBIT A

Source: 20414-D01-2016 (Errata) pages 10-11

A notional revenue requirement approach struggles to account for erratic past cost results while a cost-of-service rate case is burdened by the perverse incentives to over-forecast

	A One-time true-up	B Notional Revenue Requirement	C Formal Cost of Service
Pro	• Extremely simple, fast • Saves expense of large rate case • Verifiable • Allows time to be spent on other priorities	• Mechanistic • Simple • Based on actuals	• Potential for a comprehensive review of costs • Results can be used as a basis for rate allocation and rate design (this can also be done on a revenue-neutral basis)
Con	• Less ideal if the one-time catch up is repeated and predictable which could encourage gaming • Assumes all current spending is prudent, accounting done correctly, and costs are fairly predictable proxies for future years (no full examination of costs)	• No full re-examination of costs • More difficult to prepare if costs are volatile and less predictable • Minimum O&M method, if chosen, may be overly harsh, especially if there is a positive upward trend	• Time consuming • Costly • Huge burden to the utility, especially operational employees who can be doing other work • Strong incentives to over-forecast

EXHIBIT A

Overall, traditional cost of service is the worst of the three options, especially if done using a forward-looking test year

Rebasing options framework for year 1 of new MRP

	One-time True-up	Notional Revenue Requirement	Formal Cost of Service
Administrative Efficiency	Simple, easiest	Not difficult to calculate	Costly, time consuming
Incentives for Cost Control & Innovation	Good because not known in advance	Efficiencies can be retained for longest period of time	Potential for forecast inaccuracies or incentive for gaming by forecasting higher costs during rebasing[1)]
Performance Based	Similar across options	Similar across options	Similar across options
Compliance with Act 5	Linked for a year	Weak link of capital and revenue due to notional treatment	Forecast relinks capital and revenues for start of PBR plan
Fairness	Less information asymmetry – based on verifiable results	Less information asymmetry – based on verifiable results	More complete examination of all issues, but with asymmetric information

Poor ■ ■ ■ ■ ■ **Good**

1) Under the forecasted test year methodology

EXHIBIT A

We recommend a one-time true-up going into the next PBR plan term

Rationale for recommendation

- **Capital spending dropped significantly during the plan as compared to the time of the last rate case**.
- PBR incentives are working with the drop in capital spending.
- However, the capital expenditure volatility makes it difficult to do the notional revenue requirement at this time.

- The business costs (aside from the wildfire issue) appear to be well under control when compared to external benchmarks as shown on later slides. An improvement is seen in distribution O&M per customer at the start of the MRP period.

- The majority of HECO's under-earning is due to the **mismatch of the actual equity ratio and the allowed equity ratio**. This issue is not resolved through a notional revenue requirement which focuses on capital and O&M costs.

- **Utility issues can be addressed in a more targeted fashion** outside of a full litigated cost of service. We don't need a rate case.

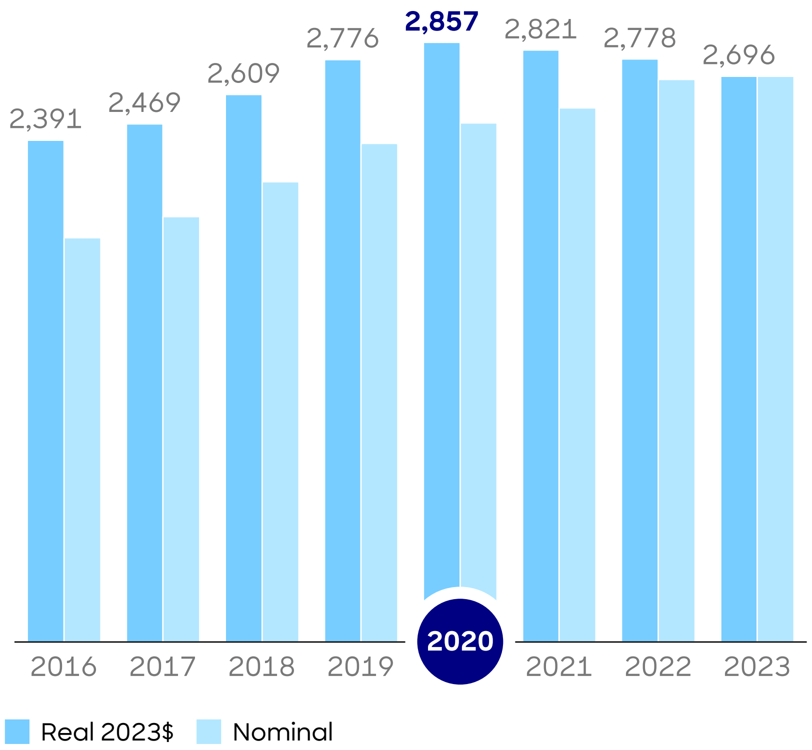
EXHIBIT A

A Rebasing Option: One time true-up

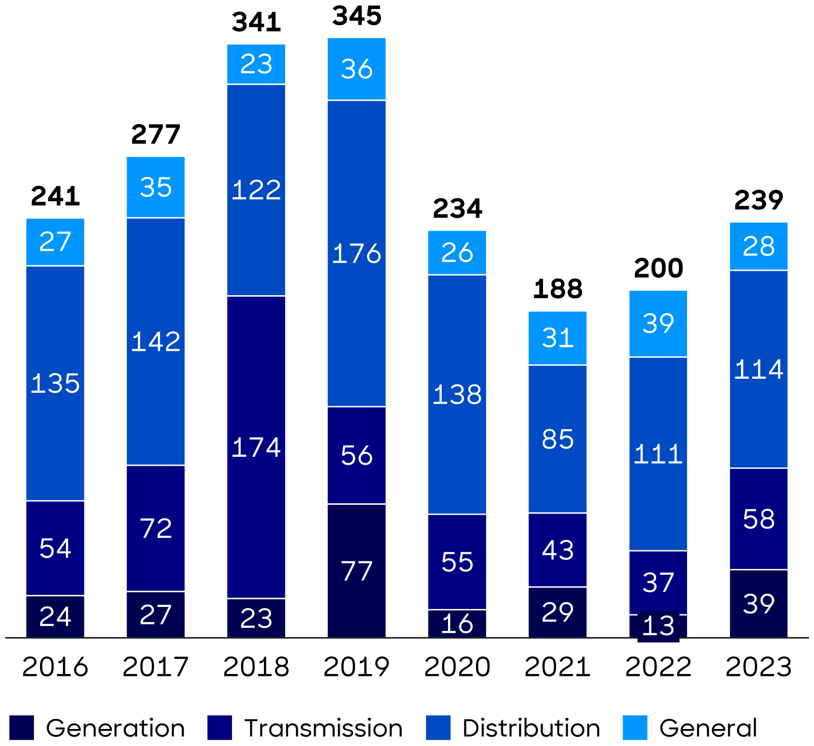
We see largely business as usual for HECO, leading us to believe rebasing is sufficient as wildfire cost recovery should be dealt with outside of a rate case

Select HECO operational metrics [2016-2023][1)]

HECO Rate Base
[USD M]



HECO Annual Capital Expenditures
[Nominal USD M]



Key methodology/ assumptions for HECO

- Look-back utilizing FERC Form 1 data for HECO (Oahu)
- Does not include Maui or costs associated with wildfires

Take-aways

- Large capital projects completed in 2018 and 2019 (transmission and distribution, respectively)
- Rate base, on a real dollar basis, peaked in 2020
- Distribution capital expenditures much lower than previous years since 2020

1) Analysis includes HECO, the Oahu utility

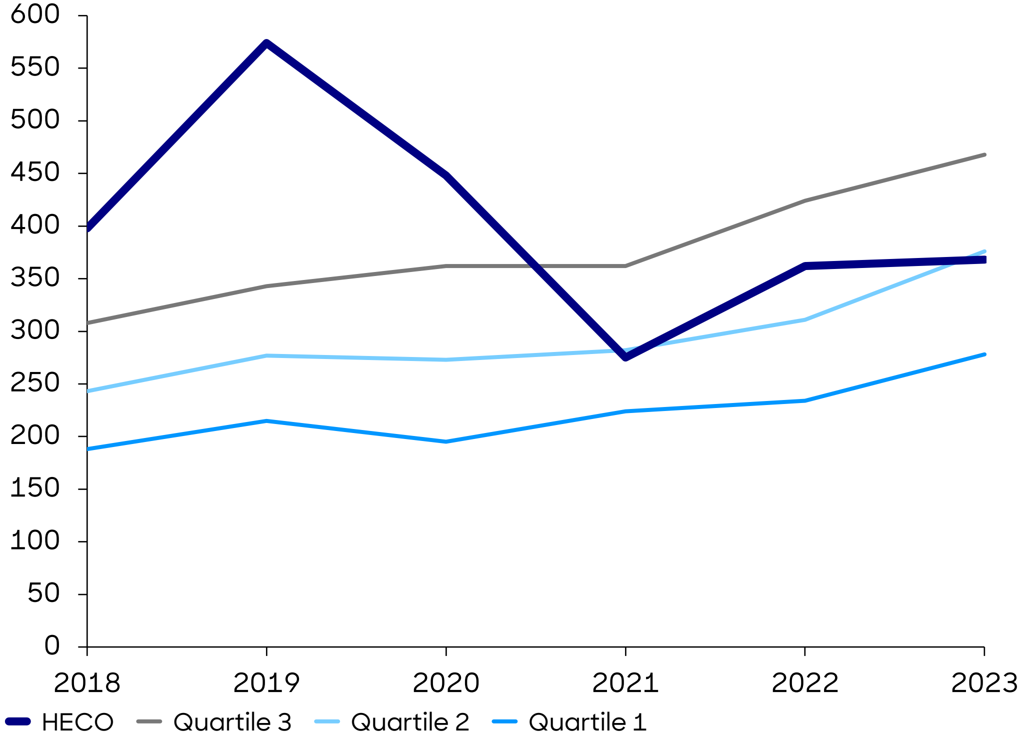
EXHIBIT A

Source: FERC Form 1 data, Roland Berger analysis

Distribution capital additions peaked in 2019 and is now approaching the US electric utility median

Select HECO operational metrics [2018-2023][1)]

Distribution Capital Additions
[USD / customer]



Key methodology/ assumptions for HECO

- Look-back utilizing FERC Form 1 data for HECO (Oahu)
- Does not include Maui or costs associated with wildfires
- Benchmarked over time to 129 national electric utilities with more than 1000 customers

Take-aways

- Company performance in capital spending improved – now shows 2nd quartile results

1) Analysis includes HECO, the Oahu utility; 2) Quartile measures show the top of the range; 3) Nominal dollars

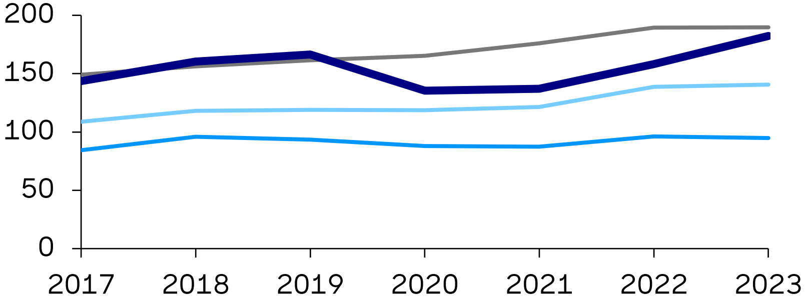
EXHIBIT A

Source: FERC Form 1 data, LaReg and Roland Berger analysis

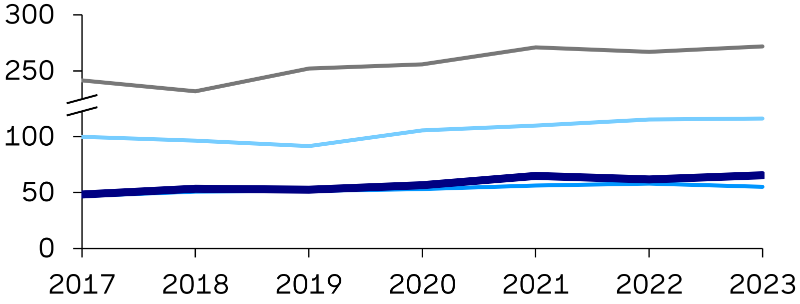
We see largely business as usual for HECO and note that the PBR mechanism has enabled improvement in distribution cost control prior to 2023

Select HECO operational metrics [2016-2023][1)]

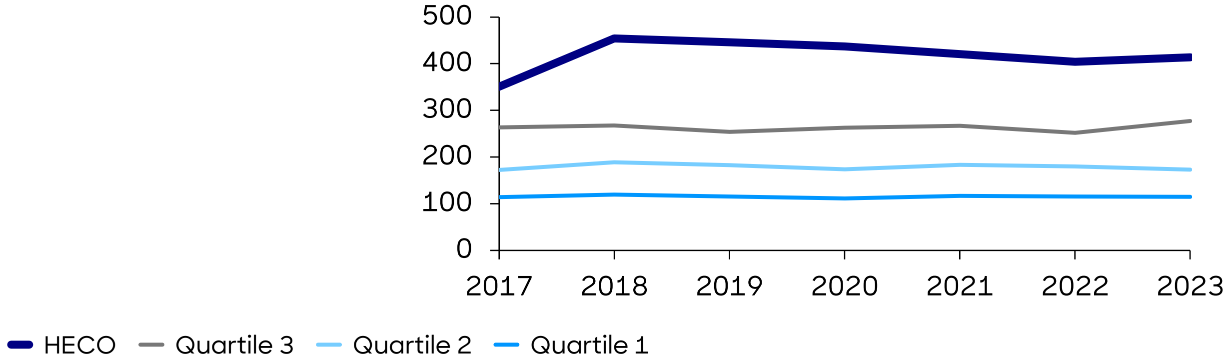
Distribution O&M [USD / customer]



Transmission O&M [USD / customer]



Administrative & General [USD / customer]



Key methodology/ assumptions for HECO

- Look-back utilizing FERC Form 1 for HECO (Oahu)
- Does not include Maui or costs associated with wildfires
- Calculated the cost on a per customer basis
- Benchmarked over time to 129 national electric utilities with more than 1000 customers

Take-aways

- Operating costs and A&G seem relatively consistent over the MRP period
- HECO's distribution O&M/customer improved, going from 4th quartile performance to the 3rd quartile

1) Analysis includes HECO, the Oahu utility; 2) Quartile measures show the top of the range; 3) Nominal dollars

EXHIBIT A

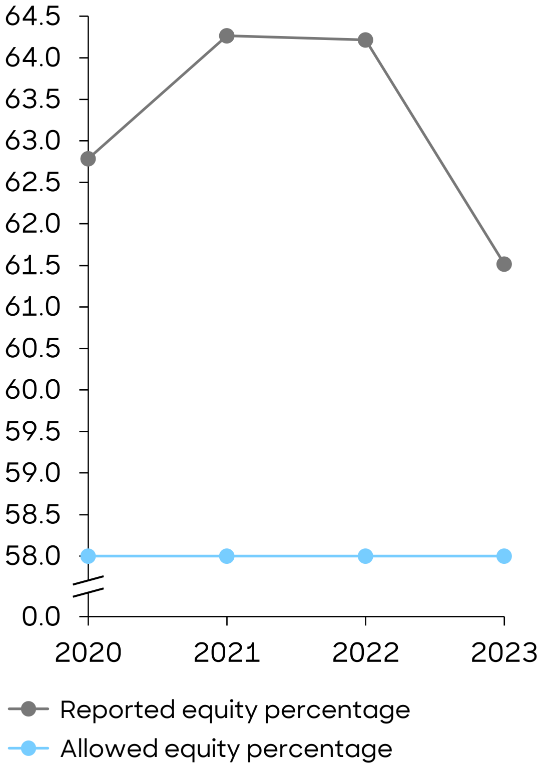
Source: FERC Form 1 data, LaReg and Roland Berger analysis

A Rebasing Option: One time true-up

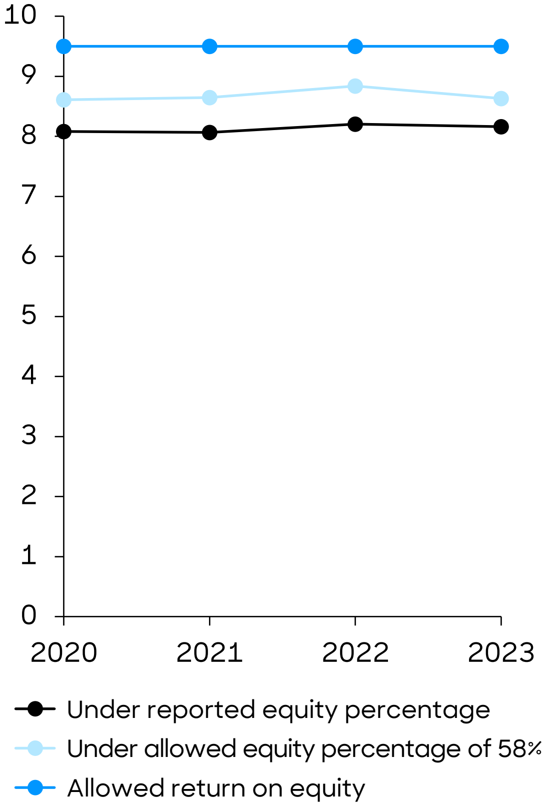
We estimate an incremental USD 15.2 – 42.9 million would be required to increase their realized ROE to their allowed ROE

One time true-up method – calculating true-up to meet allowed ROE in 2023

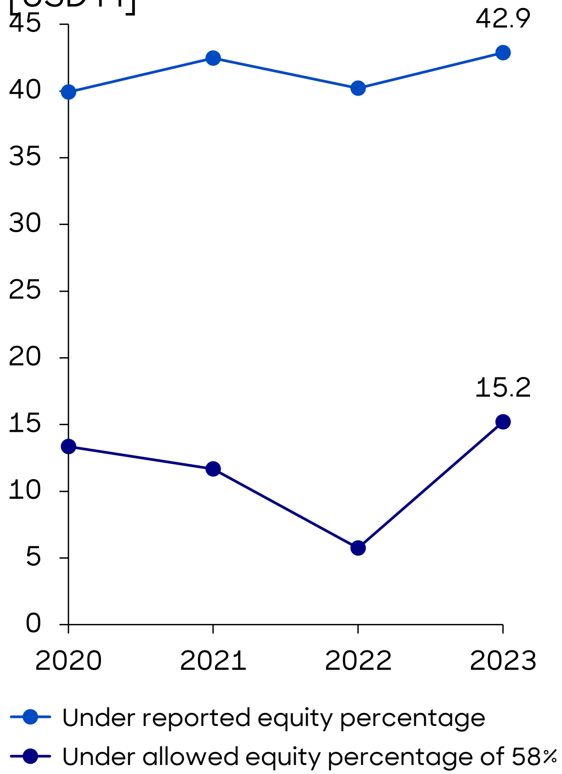
Equity percentage
[%]



Return on equity
[%]



True-up to meet allowed ROE
[USD M]



Key methodology/ assumptions for HECO

- Look-back utilizing FERC Form 1 data for HECO (Oahu)
- Adjusted actual equity percentage to allowed equity percentage under last settlement
- 2023 true-up amount should be adjusted to inflation for 2025 value
- Excludes wildfire, incremental resilience, and incremental depreciation (all outside of rebasing)

EXHIBIT A

Source: FERC Form 1, Roland Berger analysis

Time and energy would be better spent on the large wildfire recovery issue outside of the rebasing proceeding

Key issues facing Hawaii Electric

Hawaii Electric's Key Drivers for a lower forecasted ROE

Issue	Addressed by
Wildfire restoration and mitigation expense	Deal with prudence and cost recovery in a separate proceeding (Z factor) Securitize prudent expenditures
Additional plant investments	Capital is currently adequately addressed in PBR construct. Large expenditures outside of business as usual, such as resiliency, can utilize the EPRM mechanism
Higher insurance premiums	Additional increases can be included in the Z factor for the next MRP for a 5-year period, after which the increases can be dealt with in base rates
Performance Incentive Mechanism penalties	Expected to be small
Higher labor costs	Inflation incorporated in PBR plan (I-X)
Higher depreciation	Does not affect ROE if done concurrently with rate change

Maui Windstorm and Wildfires Event Related Costs as of 9/30/24 [USD m]

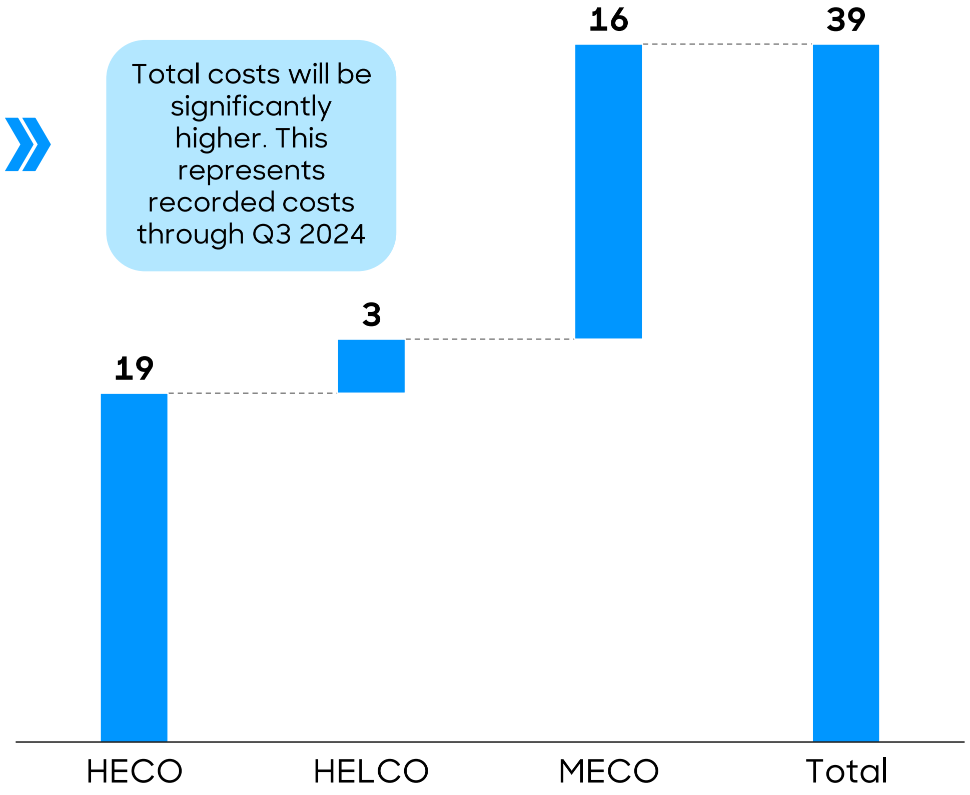


EXHIBIT A

Source: File “Dkt 2018-0088 HECO Cos Resp to PUC Staff Follow-Ups Qs_PBR Oct WG redacted” from Docket 2018-0088, Docket 2023-0349 – Application to Defer Maui Windstorm and Wildfire Costs

Other comments and recommendations include:

Cost Trackers	Recommend no change to cost trackers at this time
Regulatory Assets/ Liabilities	Recommend target revenues be adjusted for items that have been fully amortized, such as audit savings. Deal with wildfire issue in a separate proceeding
Depreciation rates	Increasing depreciation rates would help improve cash flow metrics at a time when the utility needs to raise capital. Increasing depreciation saves customers from financing charges in the long run.
Rate allocation/ Rate design	If needed, can be done on a revenue neutral basis. If there is a cost of service proceeding then rate allocation and rate design should be done.

EXHIBIT A

B. Appendix: Attachments

EXHIBIT A

Income shortfall to earn allowed ROE [USD m]

Line #		2015	2016	2017	2018	2019	2020	2021	2022	2023	Notes
1	**Reported Financial Information**										
2	Net income	136.8	143.4	121.0	144.7	157.9	170.4	178.7	190.0	195.0	Form 1, Page 117, line 74
3	Preferred dividents	(1.1)	(1.1)	(1.1)	(1.0)	(1.1)	(1.1)	(1.1)	(1.1)	(1.1)	Form 1, Page 118, line 29
4	Net income after preferred	135.7	142.3	120.0	143.7	156.8	169.3	177.6	188.9	194.0	Line 2 + Line 3
5											
6	**Reported Capital Structure**										
7	Short term debt (notes payable)	-	-	5.0	25.0	89.0	50.0	-	88.0	-	Form 1, Page 112, line 36
8	Long term debt	880.5	920.5	930.5	1,005.5	1,012.0	1,122.0	1,142.0	1,132.0	1,432.0	Form 1, Page 112, line 23
9	Preferred Equity	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	Form 1, Page 112, line 3
10	Common Equity	1,728.3	1,799.8	1,845.3	1,957.6	2,047.4	2,141.9	2,261.9	2,344.2	2,409.1	Form 1, Page 112, line 15 less line 9 above
11	Total Funding	2,631.2	2,742.6	2,803.1	3,010.5	3,170.6	3,336.2	3,426.2	3,586.4	3,863.4	Sum of lines 7 to 10
12											
13	**Two Year Average Capital Structure**										
14	Short term debt (notes payable)		-	2.5	15.0	57.0	69.5	25.0	44.0	44.0	Average of prior and current year Line 7
15	Long term debt		900.5	925.5	968.0	1,008.8	1,067.0	1,132.0	1,137.0	1,282.0	Average of prior and current year Line 8
16	Preferred Equity		22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	Average of prior and current year Line 9
17	Common Equity		1,764.1	1,822.5	1,901.5	2,002.5	2,094.6	2,201.9	2,303.0	2,376.6	Average of prior and current year Line 10
18	Total Funding	-	2,686.9	2,772.9	2,906.8	3,090.6	3,253.4	3,381.2	3,506.3	3,724.9	Sum of Lines 14 through 17
19											
20	**Capital Structure Ratios**										
21	Short term debt (notes payable)		0.0%	0.1%	0.5%	1.8%	2.1%	0.7%	1.3%	1.2%	Line 14/Line 18
22	Long term debt		33.5%	33.4%	33.3%	32.6%	32.8%	33.5%	32.4%	34.4%	Line 15/Line 18
23	Preferred Equity		0.8%	0.8%	0.8%	0.7%	0.7%	0.7%	0.6%	0.6%	Line 16/Line 18
24	Common Equity		65.7%	65.7%	65.4%	64.8%	64.4%	65.1%	65.7%	63.8%	Line 17/Line 181
25	Total Funding		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	Sum of lines 21 to 25
26											
27	Interest On Long-Term Debt		41.8	43.3	45.6	45.8	46.1	49.6	50.6	58.9	Form 1, Page 117, Line 58
28	Amortization Of Debt Discounts & Expense		1.7	1.9	1.6	1.5	1.4	1.4	1.4	1.2	Form 1, Page 117, Line 59
29	Total Long term Debt Interest Cost		43.5	45.1	47.3	47.3	47.5	50.9	51.9	60.1	Line 27 + Line 23
30	Long term Interest Rate		4.836%	4.878%	4.885%	4.687%	4.451%	4.497%	4.568%	4.686%	Line 32/Line 28
31											
32	Return on Equity (Book value)		8.1%	6.6%	7.6%	7.8%	8.1%	8.1%	8.2%	8.2%	Line 4/Line 17
33	Income required for allowed ROE at actual equity structure		167.6	173.1	180.6	190.2	199.0	209.2	218.8	225.8	9.5% Allowed ROE * rev. common equity (line 17
34	Difference		25.3	53.2	37.0	33.4	29.6	31.5	29.9	31.8	line 34 - Line 4
35	Pre-tax income required		**34.0**	**71.6**	**49.8**	**45.0**	**39.9**	**42.5**	**40.2**	**42.9**	Line 28/(1-tax rate)

EXHIBIT A

Line #		2015	2016	2017	2018	2019	2020	2021	2022	2023	Notes
	Adjusted Capital Structure to 58%										
1	Short term debt (notes payable)		-	5.0	25.0	89.0	50.0	-	88.0	-	No change; Page 1 line 7
2	Long term debt	1,082.8	1,129.6	1,150.0	1,217.1	1,220.4	1,328.9	1,416.7	1,396.0	1,600.3	Line 5 less sum of lines 1, 3 and 4
3	Preferred Equity	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	No change; Page 1 line 9
4	Common Equity	1,526.1	1,590.7	1,625.8	1,746.1	1,839.0	1,935.0	1,987.2	2,080.1	2,240.8	58% of line 5
5	Total Funding	2,631.2	2,742.6	2,803.1	3,010.5	3,170.6	3,336.2	3,426.2	3,586.4	3,863.4	No change; Page 1 line 11
6											
7	**Average Capital Structure**										
8	Short term debt (notes payable)			2.5	15.0	57.0	69.5	25.0	44.0	44.0	Average of prior and current year Line 7
9	Long term debt		1,106.2	1,139.8	1,183.6	1,218.7	1,274.7	1,372.8	1,406.4	1,498.2	Average of prior and current year Line 8
10	Preferred Equity		22.3	22.3	22.3	22.3	22.3	22.3	22.3	22.3	Average of prior and current year Line 9
11	Common Equity		1,558.4	1,608.3	1,685.9	1,792.5	1,887.0	1,961.1	2,033.7	2,160.5	Average of prior and current year Line 10
12	Total Funding		2,686.9	2,772.9	2,906.8	3,090.6	3,253.4	3,381.2	3,506.3	3,724.9	Sum of Lines 14 through 17
13											
14	**Impact of Changes on ROE**										
15	Increase in long term debt		205.7	214.3	215.5	210.0	207.7	240.8	269.4	216.2	Line 9 less Page 1 Line 15
16	Interest cost		4.836%	4.878%	4.885%	4.687%	4.451%	4.497%	4.568%	4.686%	Page 1, Line 30
17	Increase in interest cost		9.9	10.5	10.5	9.8	9.2	10.8	12.3	10.1	Line 15 * Line 16
18	Tax shield on debt		(2.6)	(2.7)	(2.7)	(2.5)	(2.4)	(2.8)	(3.2)	(2.6)	25.8% tax rate on line 38 * line 17
19	Net increase in interest cost		7.4	7.8	7.8	7.3	6.9	8.0	9.1	7.5	Line 17 + Line 18
20	Original net income after preferred		142.3	120.0	143.7	156.8	169.3	177.6	188.9	194.0	Page 1 line 4
21	Net income including increase in interest		134.9	112.2	135.9	149.5	162.5	169.6	179.8	186.4	Line 20 less line 19
22	Revised average common equity		1,558.4	1,608.3	1,685.9	1,792.5	1,887.0	1,961.1	2,033.7	2,160.5	Average of prior and current equity; line 4
23	Revised ROE with hypothetical structure		8.7%	7.0%	8.1%	8.3%	8.6%	8.6%	8.8%	8.6%	Line 21/Line 22
24											
25	**Income shortfall (surplus)**										
26	Income required for allowed ROE at 58% equity structure		148.0	152.8	160.2	170.3	179.3	186.3	193.2	205.2	9.5% Allowed ROE * rev. common equity (line 22)
27	Original net income after preferred		142.3	120.0	143.7	156.8	169.3	177.6	188.9	194.0	Line 20
28	Difference		5.7	32.8	16.5	13.4	9.9	8.7	4.3	11.3	Line 26 less line 27
29	Pre-tax income required		**7.7**	**44.2**	**22.2**	**18.1**	**13.4**	**11.7**	**5.7**	**15.2**	Line 28/(1-tax rate)
30											
31											
32	**Calculations of Composite Income Tax Rate:**										Source:
33	State Tax Rate	6.0%									Docket Number 2019-0085
34	Federal Tax Rate	21.0%									Hawaiian Electric Company, Inc.
35	State Tax Rate	6.0%									2020 Test Year
36	Federal Tax Rate x	21.0%									Direct Testimonies Book 10
37	Federal Tax Effect on State Tax	-1.3%									HECO 2801
38	Composite Income Tax Rate	25.8%									Page 12

EXHIBIT A

		2020	2021	2022	2023	
	Analysis of current deficiency					
	Deficiency keeping current equity ratio					
1	Net income after preferred	169.3	177.6	188.9	194.0	Att 1, Line 2
2	Ave Common Equity	2,094.6	2,201.9	2,303.0	2,376.6	Att 1 line 17
3	Current ROE	8.1%	8.1%	8.2%	8.2%	Line1/Line 2
4						
5	Income required for 9.5% at current equity structure	199.0	209.2	218.8	225.8	=9.5%*Line 2
6	Difference	29.6	31.5	29.9	31.8	Line 5 - Line 1
7	Pre-tax income	**39.9**	**42.5**	**40.2**	**42.9**	25.8% Line 6/ (1- tax rate); Tax on Att 1 line 38
8	ROE - with one time top up (current equity ratio)	9.5%	9.5%	9.5%	9.5%	Check, line 7/Line 2
9						
10	Deficiency keeping settlement 58% equity ratio					
11						
12	Income required for allowed ROE	179.3	186.3	193.2	205.2	Att 1 line 25
13	Income required for 9.5% at current equity structure	169.3	177.6	188.9	194.0	Att 1 Line 20
14	Difference	9.9	8.7	4.3	11.3	Line 12 - Line 13
15	Pre-tax income required	**13.4**	**11.7**	**5.7**	**15.2**	Line 14/ (1- tax rate); Tax on Att 1 line 38
16						
17	**Impact of key equity ratio and audit savings give back**					
18	Impact of the actual versus 58% ratio	26.6	30.8	34.5	27.7	Line 7 - Line 15
19	Audit savings give back	4.6	4.6	4.6	4.6	Order 37696, tariffs, Sheet 104F pdf, page 74; March 23, 2021
20	Pre-tax earnings impact	31.19	35.43	39.09	32.28	Sum of line 18 and 19
21	After tax earnings impact	23.16	26.31	29.02	23.97	Line 20/(1-tax rate); Tax on Att 1 line 38
22						
23	If those items are corrected, the resulting net income is	192.50	203.95	217.95	217.92	Line 1 + Line 21
24	The resulting ROE would have been:	9.2%	9.3%	9.5%	9.2%	Line 23/Line 2
25						
26	Which is very close to the allowed ROE	97%	97%	100%	97%	Line 24/ Line 26

EXHIBIT A

EXHIBIT A

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF HAWAII

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Performance-Based Regulation.	DOCKET NO. 2018-0088

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this date a copy of the foregoing document was duly served upon the following parties as set forth below:

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