Exhibit 1

Roland Berger, Interconnection and RFP Process Improvement - Recommendations (February 2021)

4824-3511-6514.1

Roland Berger

Interconnection and RFP Process Improvement

Recommendations

ulupono INITIATIVE®

February 2021

The project objective is to define a set of actionable steps for Hawaiian Electric to resolve ongoing Interconnection and RFP issues

Interconnection and RFP Process Improvement Overview

Project Objectives

> Identify key issues and pain points for interconnection of DER and utility scale renewables and the RFP process for renewables and grid services contracts

> Gather best practices and solutions through research and interviews of utilities on the mainland

> Provide recommendations on potential solutions to help facilitate DER and renewable development, given the issues identified

> Present a small number of actionable items that would resonate with Hawaiian Electric and the regulator, not a high-level overview of the issues

Sources

> Interviews of Hawaii stakeholders and experts

> Public sources including, DOE, EIA, NREL, LBNL, HPUC, HSEA

Note: The study was limited to activities under HECO's control, not to local county or city permitting issues

Source: Roland Berger

We defined they key issues within Hawaiian Electric's control that could be reasonably addressed

Key issues on DER and renewable energy development

DER Interconnection Delays

> Old fashioned view on available capacity – not reflecting updated inverter technology

> A large percentage of projects require energy service upgrades

> No standardized process – differences between islands

> Meter swaps are overly burdensome to schedule

> Many processes could be automated through better use of technology

Utility-scale Interconnection

> High cost compared to mainland; differences of costs between islands

> High level of variability between estimates and actual cost – this risk creates a lot of uncertainty for developer

> Delays can delay the RFP and put the auction in jeopardy

Renewable RFPs

> Unreasonable specifications limit least cost solutions and onerous terms and conditions in the RFP place too much burden on HECO's counterparty

> Limited upfront stakeholder engagement from bidders means that preventable issues can threaten the success of the RFP

> HECO requests and provides unrelated and irrelevant information too early in the process

> The RFP in general is overwhelmingly long and unstructured, making it difficult for new participants to engage

Source: Roland Berger

Roland Berger

Recommendations for Hawaiian Electric to facilitate DER and renewable development to meet RPS goals

DER Interconnection Delays

> Standardize rules and processes across the islands

> Invest in modeling capabilities and data to better estimate available capacity on secondary circuits; ensure transparency

> Invest in a DER application portal for the public to access key information and applicants to have real time access to utility communications

> Prioritize applications based on transparent criteria

> Ensure accountability through public data or even incentives for improved DER Interconnection wait times

Utility-scale Interconnection

> Increase transparency of total costs – require HECO to provide the developer a breakdown on hours and rates for time spent on projects from engineers, field teams and project managers

> Interim step: Offer fixed price interconnection for small projects (i.e. under 1MW) and consider Cost Envelope options with narrow range for larger projects

> Long term solution: move responsibility for the interconnection cost to the utility to add to rate base

Renewable RFPs

> Update design standards and technical requirements to reflect advancements in technology and communications

> Rewrite the terms and conditions to make it less onerous for the developer

> Simplify data requirements and data provided in RFP, especially in the early stages

> Make the evaluation criteria clear and easy to understand

> Establish a regular cadence for RFPs until 100% renewable energy is achieved

Source: Roland Berger

Roland Berger

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Roland Berger

A. Utility Scale Interconnection Costs

Roland Berger

Independent Power Producers have complained about the high and variable cost of interconnections, lack of transparency and delays

Common issues regarding interconnection costs

Issue	Explanation
High costs, variability in costs	> Interconnection has become a large percentage share of renewable project costs, over which the developer has little to no control. Developers report significantly higher costs in Hawaii than on the mainland. > Some equipment required is dated with newer version available at lower cost and/or better functionality. > High costs for project management (~10% of total cost) > There is variation in cost estimates for seemingly similar projects, across one island and between islands. Developers report that costs on Oahu are significantly higher for similar projects in Maui. > Given the variability in costs, and lack of insight into final costs, developers must put in a large contingency for this into capital estimates (driving up final costs for the project, and thus, for ratepayers).
Lack of transparency	> There is no breakdown of large cost items, such as HECO project management, which can total several million dollars.
Delays	> Interconnection study requires ~6 months, with perfect information from developer – longer if additional information is required. > Delays may be caused by overly engineered solutions, not taking into account new technology in inverters which mitigate some of the reliability concerns.

HECO's lengthy interconnection study process delayed the latest RFP by a year. Developers had GCOD in 2021, but the time required to do the interconnection studies caused a delay, pushing back the in-service date.

Source: Expert interviews, Roland Berger

Roland Berger

Potential solutions for interconnection cost issues for large-scale projects

Recommendations to consider

Cost envelope/fixed price estimates

Description

> Developer pays a higher up front cost for a more accurate interconnection study. If total cost is outside of a set percent (e.g. 25%) from the estimate, the utility takes responsibility for it.

Pros

> Developer has more confidence in the total cost of interconnection, lowering risk/uncertainty.

> Utility is provided with upfront resources to complete a higher quality cost estimate.

Cons

> The allowed deviation can still significantly impact project economics (risk and uncertainty remain).

> The cost envelope option has shown limited uptake in regions where offered.

Shift the cost of interconnection to rate base

Description

> The cost of the interconnection for utility-scale projects are added to rate base.

Pros

> Developers will have high confidence in project economics, when no longer responsible I/C costs, over which it has very little control. When these uncontrollable risks are eliminated, the developer should be able to bid more competitive pricing

> The PUC has better leverage than developer in pushing for lower cost solutions for the interconnection

Cons

> Under expected PBR, it is unclear if these interconnection costs would require EPRM treatment for HECO to get immediate recovery (outside of the ARA).

> The PUC would need to ensure cost effectiveness of the interconnection in an approval process (if EPRM).

Source: Roland Berger

Roland Berger

California instituted a cost envelope program that provides interconnection cost estimates

Case study - Cost Envelope Estimate

California Public Utilities Commission

Project eligibility requirements

> Available for projects applying to the Fast Track and Independent Study Processes.
> Developers pursuing the independent study process must complete both a System Impact Study and Facilities Study in order to elect the Cost Envelope.

Application process

> Projects that complete either the Fast Track Initial Review or Supplemental Review must pay a $2,500 deposit.
> The utility is allowed 20 business days to develop a cost estimate following the completion of the engineering review phase.

Terms & conditions

> Developers may choose to opt into the cost envelope program
> Utilities will be given additional up-front study time and more financial resources for fast-track and independent study projects
> The range of the cost envelope will be set at 25% (both above and below the utility provided estimate)
  – Limits developer liability to 25% above estimated interconnection costs, with the utility responsible for the difference.
  – If the interconnection costs are lower than 25% pf the estimated cost, the utility will refund the difference between the actual cost and the lower bound.
> The CPUC also mandates the creation of a memorandum account to track interconnection costs that fall above or below the 25% envelope.

Intended outcomes

> Enables utilities to spend an appropriate amount of time to conduct due diligence & produce high-confidence upfront cost estimates
> Increase utility accountability for making accurate cost estimations to promote predictability of interconnection costs, thus reducing risk and cost overruns for developers
> Improves the reporting process for data and increases the transparency of interconnection costs

Source: CPUC, NREL, Desk research, Roland Berger

Roland Berger

California has implemented fixed-price interconnection for projects under 1 MW

Case study – Fixed price

California Public Utilities Commission

Project eligibility requirements

> Must meet requirements for fast track interconnection review process or the Independent Study Review Process

> Projects must be 1 MW or smaller and not require substation upgrades or system upgrades greater than $500,000.

Application process

> The utility will provide a fixed price interconnection for a fee of $10,000.

> 60 days after the applicant provides required technical information, the utility is required to provide the fixed price for interconnection.

Terms & conditions

> Utilities will provide a detailed breakdown of cost elements not included in the fixed price (e.g., environmental studies, environmental mitigation, permits, etc.)

> Any over- or under-collection of costs is allocated to ratepayers, trued up in customer rates through the General Rate Case (GRC) capital work order process.

Intended outcomes

> Enables utilities to spend an appropriate amount of time to conduct due diligence & produce high-certainty cost estimates

> Passes on the risk of cost overruns from the developers to the ratepayers

Source: CPUC, NREL, Desk research, Roland Berger

Roland Berger

Small improvements are possible; the long term solution would require stakeholder engagement and PUC approval

HECO may be unlikely to accept the long term solution until PBR is better defined

1 Immediate steps

> **Increase transparency of total costs** – require HECO to provide the developer a breakdown on hours and rates for time spent on projects from engineers, field teams and project managers

2 (Optional) interim steps

> Offer fixed price option for small projects (i.e. under 1MW)
> Consider Cost Envelope options within narrow range

3 Long term solution

> Move responsibility of interconnection out of the developers hands – shift the cost to the utility rate base instead of having the cost flow through the PPA cost
> Treated as any other distribution grid upgrade – large projects will be subject to EPRM
> Allows developers to reduce risk, lower contingency and provide more competitive pricing
> The utility would likely welcome an opportunity to add to rate base, provided there is an avenue for immediate recovery of large project costs

This will increase transparency and allow a thorough review by PUC

Ratepayers pay for interconnection, whether through the PPA or rate base. Shifting it to rate base will increase transparency for the PUC's review and give the developer more confidence in their bid.

Source: Roland Berger

Roland Berger

Six states implemented cost envelope pricing to address interconnection upgrade costs, but some policies are only non-binding guidelines

States that provide interconnection cost envelope pricing estimates


Massachusetts

California


Utah


Minnesota


New York

Oregon

Financially binding ← → **Not financially binding**

Note: The term "financially binding" refers to the mandate instituted by each jurisdiction's utility commission that utilities must incur the additional costs if the variation in the actual interconnection cost from the initially quoted estimate is greater than a specified threshold

Source: NREL, Desk research, Roland Berger

B. Interconnection Delays

Roland Berger

HECO's average DER interconnection permission to operate (PTO) wait time is longer than other peer IOUs

DER Interconnection times – Peer utility comparison

	Hawaiian Electric	conEdison	SDGE	aps	Southern California EDISON	nationalgrid
Geography	Hawaii	New York	Southern California	Arizona	Southern California	Massachusetts
State-level solar penetration[1)]	12.6%	N/A	19.9%	6.6%	19.9%	13.7%
State-level installed solar energy capacity[5)]	1.4 GW	2.5 GW	30 GW	4.8 GW	30 GW	2.9 MW
Average permission to operate wait time[2)3)]	~60 days[4)]	~15 business days	~15 business days	~30 days	~15 business days	~30-60 days
Max. capacity eligible for fast-track application	25 kW	50 kW	30 kW	20 kW	10 kW	25 kW

1) Solar generation as percentage of total generation, incl. utility scale systems 2) From application submission to permission to operate 3) Average wait times for a typical DER systems that are eligible for fast-track applications 4) Has historically been 3-6 months – Wait time decreased due to new PTO reforms for systems 25 kW or smaller 5) As of Q3 2020

Source: LBNL, SEIA, Roland Berger

A variety of pain points have resulted in long wait times for PV system interconnections for HECO customers

Pain points	Pain point description
Permitting process	> Utilities must inspect newly installed medium-large PV systems, which results in customers waiting 6-8 weeks to receive permission to operate, even with the activation of inverter safety features such as volt-var and volt-watt > The enforcement of a technical verification procedure for new small solar generation systems before customers can operate those systems is causing numerous projects to be unnecessarily rejected, thus causing further delays
Energy service upgrades	> ~20% of all DER interconnection requests require an electrical service upgrade > Energy service upgrades are taking on average 6 months to complete, compared to an average completion time of one week for comparable US utilities
Unique interconnection requirements	> A lack of standardization of interconnection requirements across different islands and within areas on the same island can result in increased installation complexity
COVID-19	> Extra precautions between customers and crews need to be taken during the COVID-19 pandemic which can create additional hardships and delays

Source: HSEA – March and April 2020 Report, Roland Berger

Roland Berger

HECO instituted some of the recommendations from the DER parties' joint letter to the PUC in June 2020 addressing delays

Recommendation	Pain point	Implementation status	HECO Response
Allow customers with inverter safety features to activate systems 25 kW or smaller upon installation	Permitting process	✓	Implemented to reduce backlog during the COVID-19 – Decision to be reviewed after 6 months
Invest in resources to complete energy service upgrades within two weeks of application	Energy service upgrades	☐	N/A
Conduct revenue meter swaps within two weeks of request	Permitting process	✓	Permits the meter change process to begin once an application is provisionally approved
Allow contractors to activate a second meter socket	Permitting process	✓	Contractors have been permitted to install temporary second meters for customers
Require HECO to implement a six-month plan to rapidly expand the interconnection process	Permitting process	✗	HECO declined to commit to this six-month plan because it would require the utility to expend resources during a time when the focus is to keep costs low

These actions have contributed to a reduction of DER interconnection wait times by half in HECO's service territory; key improvement was automatic activation for systems under 25 kW

Source: Desk research, HSEA, Roland Berger

Roland Berger

A review of best practices revealed similar issues and set of solutions across mainland jurisdictions

High level review of best practices for DER Interconnection

1 **Standardization of rules and processes**: uniform application of standards and rules across utilities or jurisdiction

2 **Transparency and data availability**: transparency on grid saturation and other utility issues will preemptively weed out non-viable projects and fast track a higher number of projects

3 **Automated process:** an online application portal should allow applicant to see status, receive real time communications and be able to respond to any issues, such as missing/incomplete data

4 **Prioritization:** applications are prioritized and expedited based on clearly defined criteria like project size, location, inverter technology

5 **Accountability:** transparency on results – publication of the metrics for interconnection wait times – *sometimes* enforced by penalties by the regulator

Source: Expert Interviews, Research, Roland Berger

Roland Berger

HECO can standardize processes and requirements across the islands, using a more centralized or top-down approach

"There are different interconnection rules for each island. Each island is run by an EVP who treats it like his own fiefdom."

> Each island has its own set of interconnection rules and processes which cause issues for developers trying to develop an efficient interconnection process for projects across HECO's territory

> HECO should redesign a centralized interconnection process that works for every island; if there is a rationale for a local exception to the HECO policy or process, the exception and the rationale should be clearly communicated to developers and customers, who should have opportunity to give feedback on the need

On O'ahu, the county/city permitting process has been causing the majority of the interconnection delays in recent months; these delays are outside of HECO's control

Source: Expert interviews, Roland Berger

By improving its modeling capabilities and data collection, HECO can improve the accuracy of estimating available hosting capacity

Data integrity and transparency issues

"HECO believes there are saturated circuits based on models using old algorithms and software. With better modeling, they can get a more accurate assessment of actual saturation by neighborhood, perhaps opening up a lot of the grid to more expedited DER interconnection."

Outdated software & technology

> The software used assumes all PV systems are "dumb" solar systems and that they are saturating the grid, when in reality, the adoption of "smart" solar systems has greatly mitigated this problem

Lack of data, transparency

> Difficult for developers to find grid capacity data for PV projects

> Current data provided may be inaccurate or only applicable to the state-level and not to specific geographies

Inefficient allocation of resources

> Too many HECO resources are utilized to do interconnection studies because it cannot accurately estimate which circuits are currently overloaded

Implications for developers & customers

> Wasted time & resources spent on projects that need not be studied or are untenable

> Longer interconnection queues

> Interconnection studies for projects that should be expedited

Implications for HECO

> Overestimates circuits that are saturated, leading to unnecessary grid upgrades

> Slowdown in DER adoption challenging ability to meet RPS targets

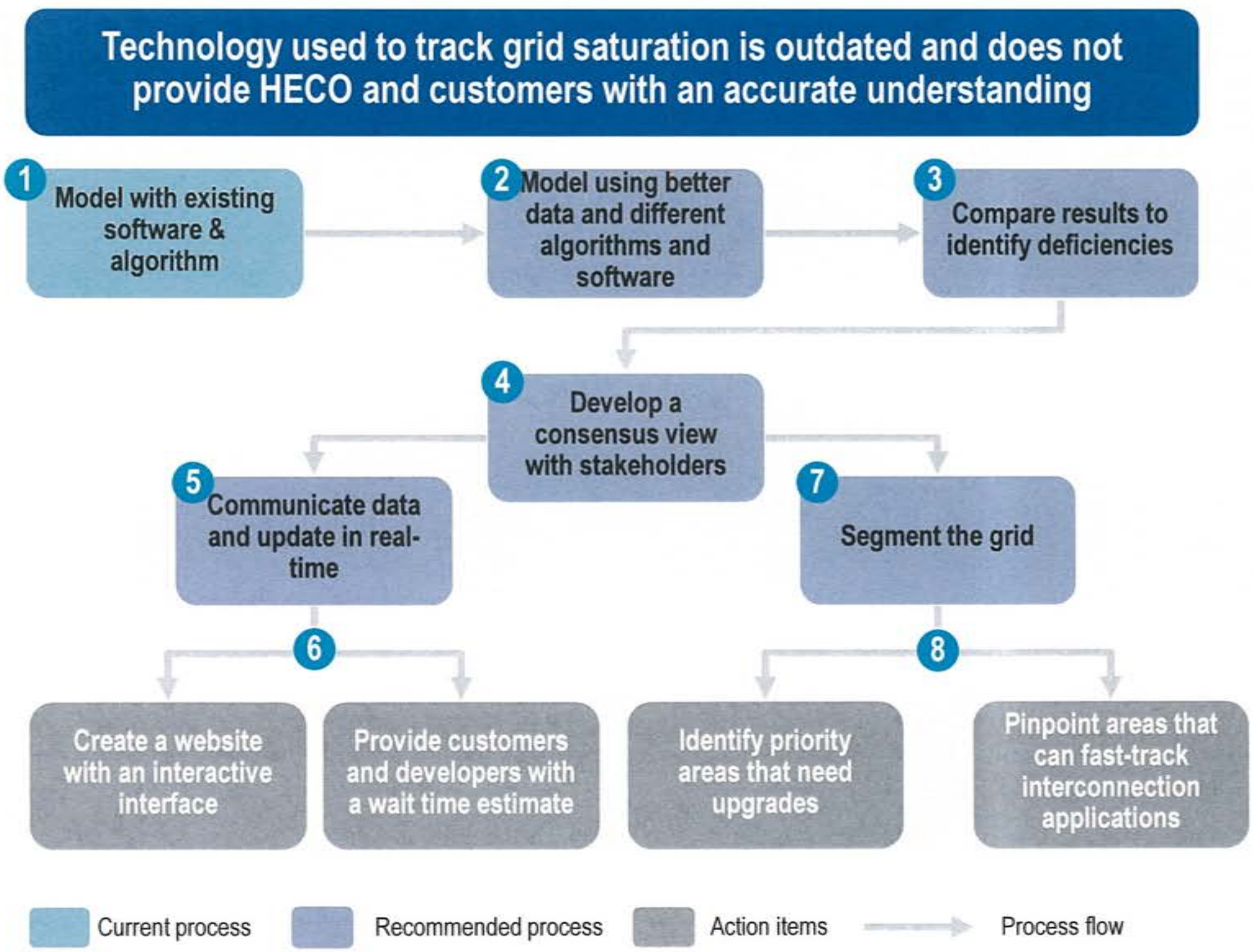
> Low customer satisfaction

Source: Desk research, Expert interviews, Roland Berger

Roland Berger

Prioritization would more efficiently allocate utility resources; an automated portal also provide a better customer experience

Process flow diagram – using technology to automate and prioritize applications



1. Grid saturation is calculated based on old data and old software assumes "dumb" solar
2. HECO should pilot newer software with improved algorithms, reflecting new technology and stakeholder data
3. Results from the old and new software should be compared and analyzed
4. HECO and stakeholders will develop a consensus view regarding appropriate modeling and methodology
5. Data should be provided to developers and updated in a timely manner as new information and technology arrive
6. The data should be disseminated through a portal that shares up-to-date information on the state of the grid and the status of their projects
7. The consensus view will depict a more accurate and up to date view of grid saturation by neighborhood
8. Areas may be segmented to target neighborhoods that need grid upgrades or areas that can withstand additions of PV capacity

Source: Expert interviews, Desk research, Roland Berger

Roland Berger

Reporting and/or regulating wait times can increase the utility's accountability for a more efficient DER interconnection process

Interconnection timeline regulations in the US (2015)

Geography	Arizona	California	Colorado	New Jersey	New York	USA – National
Regulated application review & approval wait time	N/A[1]	25 days	25-30 days	13-18 days	15-20 days	N/A[1]
Median application review & approval wait time	22 days	20-23 days	25-32 days	14-15 days	10 days	17-18 days
Applications exceeding review & approval time requirements	N/A	37%	58%	52%	38%	N/A
Regulated PTO wait time[2]	N/A[1]	30 days	10 days	20 days	5 days	N/A[1]
Median PTO wait time	12-13 days	10-12 days	10-11 days	11 days	6 days	10-12 days
Applications exceeding PTO time requirements	N/A[1]	38%	10%	23%	53%	N/A[1]

Commentary

> The Public Utilities Commissions in Colorado, New Jersey, and New York have promulgated wait time standards – enforcement is nonexistent

> The California Public Utilities Commission has the power to levy penalties for excessively delayed interconnection processes and mandate process changes

> New York instituted an earning adjustment mechanism for maintaining a certain service level for new interconnections in 2017. It was repealed in 2019 as the stakeholders agreed issues could be been resolved in more direct and effective ways than incentives

> Arizona implemented wait time standards in 2019 but with no enforcement mechanisms

1) Jurisdiction does not have interconnection timeframe requirements 2) If inspection and witness test for PV systems not waived

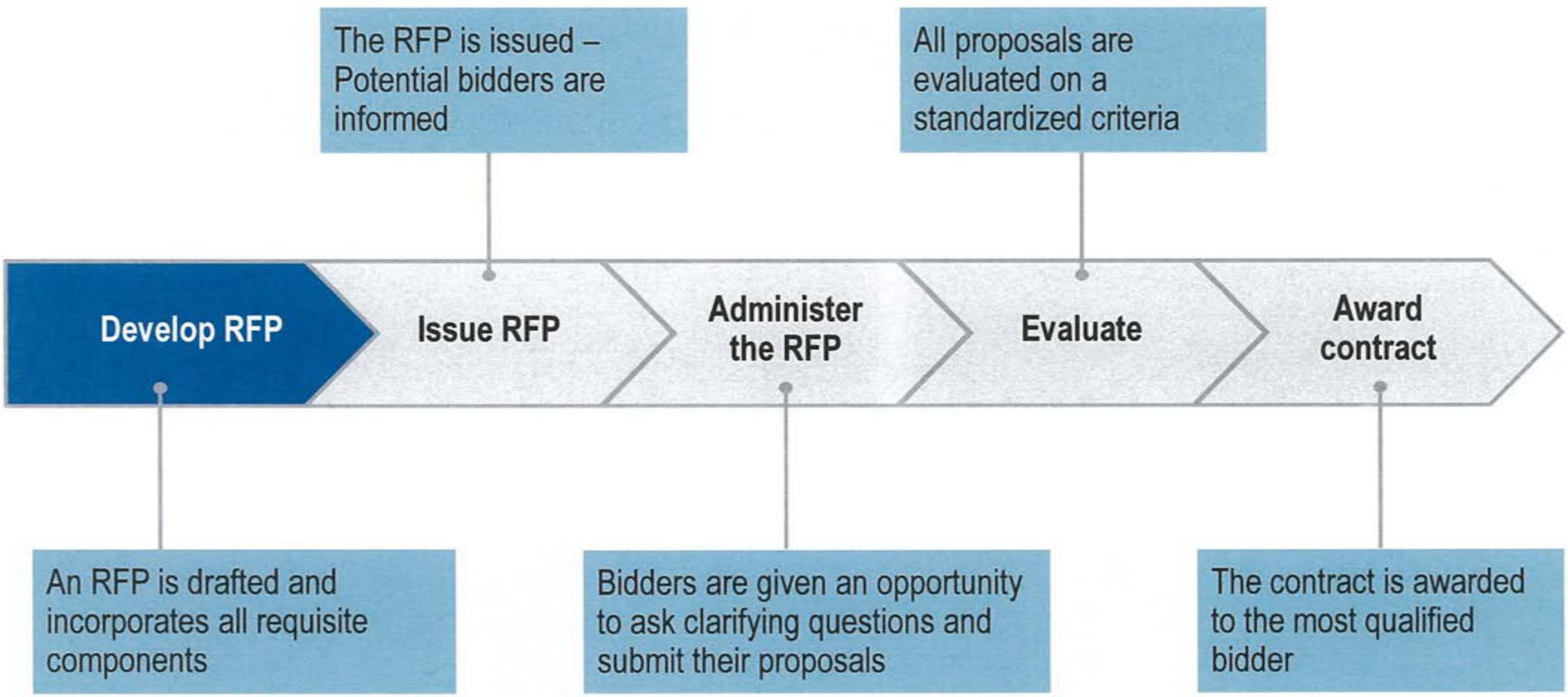
Source: NREL, Desk research, Roland Berger

C. RFP development

Roland Berger

We focused on the first step of the RFP procurement process, RFP development

RFP procurement process



Area of focus

Source: Desk research, Roland Berger

Roland Berger

Common pitfalls affecting utilities' RFP development efforts can be grouped into five categories

Common mistakes made during the RFP development process

Unreasonable specifications

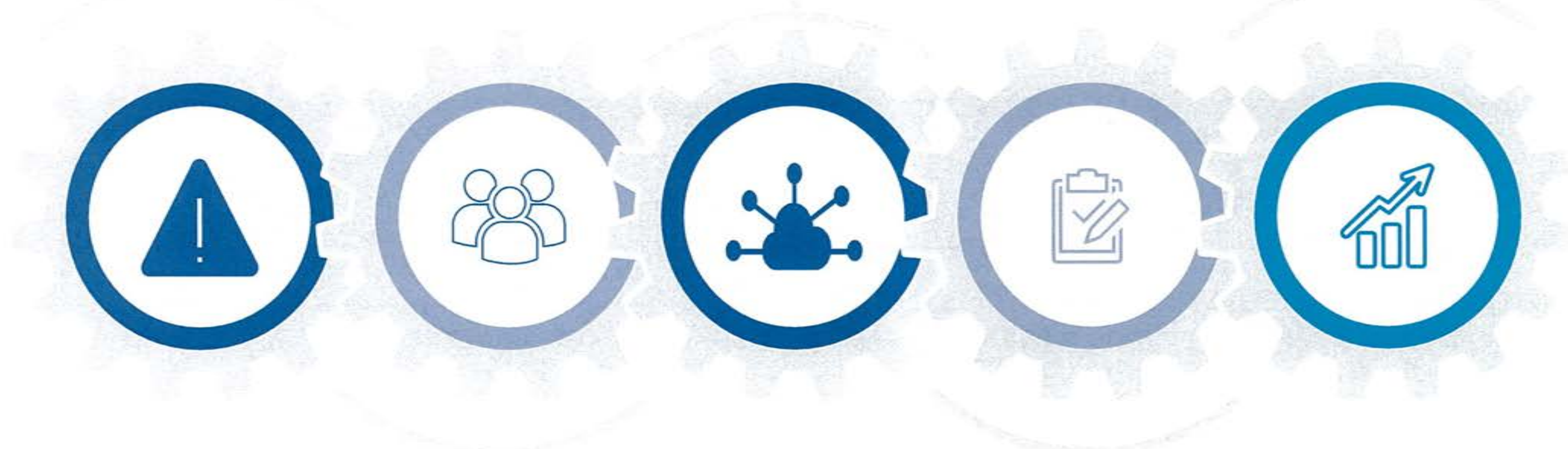
Specifications and terms are too restrictive, unstructured, or ambiguous

Insufficient or extraneous data provided / requested

Data being provided to/from potential bidders is not relevant and is time consuming to process

Competing KPIs

The proposal does not specify measurement will be used as the basis of determining system performance



Lack of stakeholder involvement

Stakeholders not engaged and do not provide adequate input into RFP

Unclear evaluation criteria

The criteria is ambiguous or the weighting of each criteria is not well organized in a table/checklist

Source: Desk research, Roland Berger

Roland Berger

Example - Milwaukee issued three RFPs for solar water heating systems over the course of 3 years before achieving success

Case study – Milwaukee Shines (2007-2010)

Milwaukee SHINES
ecoCITY of MILWAUKEE

Milwaukee Shines is the city of Milwaukee's solar program.

The city developed and issued an RFP to **install solar water heater systems on six of the city firehouses**.

RFP #1

Fall 2007

Unreasonable specifications

> The City had overdesigned the systems, including too many specific equipment requirements, resulting in the project being overly specified

> The bids received were at least double the project budget

> The RFP did not provide the flexibility to for developers to offer a low cost design

RFP #2

Spring 2009

Lack of stakeholder engagement

> It was determined that several roofs required structural reinforcements before the installation of the new PV systems

> It was incorrectly assumed that the fire department was willing to assume O&M responsibilities, which led to immense pushback for the project

RFP #3

Spring 2010

Success!

> RFP was redesigned to be outcome based, specifying desired levels of system output, rather than prescribed equipment requirements

> The city negotiated O&M responsibilities with the fire department, on the condition their staff received training, which was included in the updated RFP

Source: The Solar Foundation, DOE, Desk Research, Roland Berger

Example - San Jose issued three different RFPs for solar PPAs to power its municipal properties

Case study – City of San Jose (2011)

CITY OF SAN JOSE
CAPITAL OF SILICON VALLEY

San Jose had a goal of meeting the city's electricity needs of its municipal properties entirely through renewable energy sources

To achieve the goal, the city issued an RFP for a fixed-rate Solar PPA

RFP #1

Unreasonable specifications

> An RFP was initiated for a 1 MW solar facility at a municipal airport

> The city had many restrictive elements such as restrictions on site access, mutual indemnification clauses, and payments being contingent on annual appropriations

> The RFP received bids that were at least triple the project budget, given contractual risks

RFP #2

Unclear KPI requirements & evaluation criteria

> An RFP was initiated for a different location and only one bid was received – The respondent failed to meet minimum requirements

> The RFP provided ambiguous evaluation criteria and did not standardize performance metrics, which led to confusion over which competing metric to use (e.g., kWh over a system's lifetime v.s. kW of installed solar)

RFP #3

Success!

> To gather more stakeholder input, the city issued a request for information and organized stakeholder meetings

> Based on this feedback, the city developed a successful RFP template that procured PPAs for 28 municipal facilities

Source: The Solar Foundation, US DOE, Desk Research, Roland Berger

HECO's RFP development process can be improved across four of these categories detailed on Slide 24

HECO's RFP development performance – Issues

RFP issues	Level of concern	Explanation
Unreasonable specifications		HECO lists too many technical specifications in their RFP which makes it difficult for bidders to comply with all requirements. In addition, there are too many exit opportunities laced into the RFP which increases risk and thus, results in higher bid prices.
Lack of stakeholder involvement		Stakeholders would share with HECO that requirements are too specified and too much information is required too soon in the process.
Insufficient or extraneous data provided / required		Some of the information and data presented in the appendices appear to not be directly relevant or belabor the underlying message
Unclear evaluation criteria		The evaluation criteria is listed throughout the RFP but is not summarized in a format that also lists the relative importance of each criterion, making it difficult for the reader to find and keep track
Competing KPIs		The RFP clearly states the appropriate method and formulae needed to measure performance standards

Low Medium High

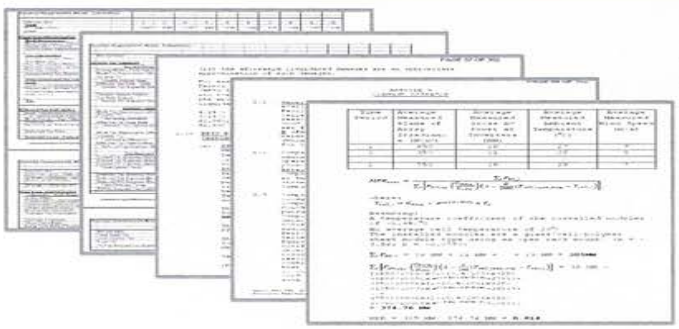
Source: Expert interviews, HECO, Roland Berger

Roland Berger

HECO's RFP is unstructured, laborious and difficult to digest; resulting from of a lack of stakeholder engagement

Comparison of RFPs for PPA contracts

Renewable Dispatchable Generation RFP – HECO



Hawaiian Electric

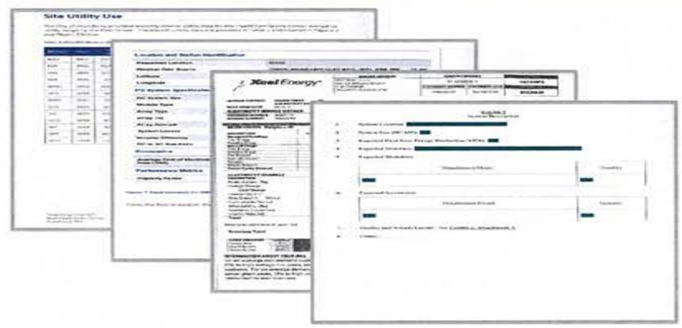
510 pages of data, definitions, requirements & guidelines

> Very detailed equipment and technical specifications
  - Lack of bidder flexibility to offer other effective solutions
  - Threshold criteria list is long and burdensome, which may intimidate qualified bidders from applying and increases the cost of bids for those who do

> Data provided are difficult to digest and require careful scrutiny to understand
  - Some data may be extraneous (e.g., Measured Performance Ratio calculation) whereas other pertinent data may be missing (e.g., electricity demand data)

> Requirements and evaluation criteria are loosely formatted and difficult to find

Solar PV RFP – City of Woodbury



94 pages of data, definitions, requirements & guidelines

> Concise and flexible technical requirements
  - Only demands technical specifications that are critical to the functionality and viability of the project
  - Threshold criteria list is short and concise

> Data provided are well organized and can easily be transposed onto an excel template for the bidder to conduct necessary analysis

> Provides a structured list of evaluation criteria

The KIUC PPA/RFP and a recent Navy RFP meets many of these best practices

Source: HECO, US DOE, Roland Berger

Roland Berger

The evaluation criteria in HECO's RFP can be improved upon by applying the guidance on RFPs issued by the U.S. DOE

U.S. Department of Energy RFP guidance – Setting expectations

> **The US Department of Energy has provided guidelines and examples on how to format a set of RFP evaluation criteria that include weighting criterion a number of points proportional to its level of importance**

> **The department also recommends including a structured schedule of deadlines to set expectations**

U.S. DEPARTMENT OF ENERGY

Evaluation/Selection Criteria:

The [COMPANY NAME] will evaluate proposals according to the evaluation criteria below. Result of this step will be the identification of the selection of a proposal for negotiation of a contract. Points will be awarded based on the relative merit of the information provided in the response to the solicitation. Selection based on the total number of points awarded by the evaluation committee.

- Proposal Cost Effectiveness 35 points
- Technical Approach/ Implementation Schedule 30 points
- Company Qualifications/Project Experience 20 points
- Project team, team experience and approach 15 points

RFP Schedule

The schedule for this RFP is as indicated below. It may be modified at the discretion of [COMPANY NAME]. An addendum will be issued in the event of any scheduling changes.

Project Milestone	Date/Time
RFP Advertised/released	
Mandatory Site Walk/Pre-Proposal Conference	1 week after release
Requests for Information (RFIs) Due	3-4 business days after site walk
Answers to RFIs distributed	3 business days after RFIs submitted
Notice of Intent to Submit Proposal	2 business days after RFIs answered
Proposal Due	3- ideally 4 weeks after RFP release
Notice of Intent to Award	
Fully Executed Contract	
Project Notice to Proceed	
System Operation Date	

Alignment and congruency on expectations

> Higher proportion of submitted proposals meeting threshold criteria resulting in less time and resources wasted

> Increased objectivity in the evaluation process

> Greater likelihood for punctual completion of project milestones

Source: Desk research, US DOE, Roland Berger

Roland Berger

Specific improvements can be made to improve HECO's Renewable RFPs

Problematic terms and conditions in HECO RFPs[1)]

Not Exhaustive

	Issue or Problem	Recommendation
Exhibit P: Sale of Facility by Seller or by Subscriber Organization (CBRE contract)	> These provisions (15 pages long) are seen by developers as overly deferential to utility, to the point where it would depress any third party from considering a purchase	> Change to a simple ROFR where utility has the right to purchase as the same terms as the third party
Community Outreach Requirements	> Community outreach is overly prescriptive in terms of timing, content and medium > This often leads to public confusion and concern	> HECO should be less prescriptive about how the developer conducts community outreach > Some requirements may be outdated given changes in the media environment (e.g. newspaper advertisements)
Liquidated Damages and Termination Provisions	> The number of circumstances and possibilities for contract termination increases risk for the developer > The term 'Liquidated Damages' is used 172 times and "termination" 100 times in the Renewable and Grid Services RFP	> The contract device of liquidated damages should not be used as a penalty – it is typically used sparingly and rationally.

1) These terms and conditions are problematic from the perspective of the developers

Source: Expert interviews, Roland Berger

Roland Berger

Given RPS goals through 2045, HECO should streamline its RFP process for utility scale and CBRE projects

HECO's RFP development performance – Issues

Issue	Recommendation
Unreasonable specifications	**Rewrite terms and conditions –** strike onerous terms and conditions which benefit solely the utility and risk the success of the program (i.e. LDs, termination clauses and complex ROFRs)
Lack of stakeholder involvement	**Update design standards and technical requirements –** Revisit design standards and requirements given advancements in technology and communications. Engage with stakeholders to revise best practices and update requirements
Extraneous data provided / requested	**Simplify data requirements –** Apply fresh perspective to data requested throughout RFP process – retaining requirements critically needed at that point in the process.
Unclear evaluation criteria	**Simplify –** clean up the evaluation criteria so it is easy and straightforward for participants to understand how their projects will be judged
General improvement	**Establish a regular RFP cadence –** Hold RFPs every 2-3 years to create a more robust market and confidence in the process. A losing project can fix its problems and compete again in 2 years. The downside of 'losing' is partially mitigated by this approach.

The current RFP process may limit the number of IPPs that participate; implications for CBRE are more meaningful – risking failure of the entire program

Source: Expert interviews, Roland Berger

D. Appendix

1. Interconnection Best Practices Review

Southern California utilities have increased accessibility and improved efficiency to expedite the interconnection process

Interconnection best practices – Southern California Region

Participating utilities

SDGE

Southern California Edison – Energy for What's Ahead

LA DWP – Los Angeles Department of Water & Power

Pasadena Water & Power

Anaheim Public Utilities

1. Information accessibility

- Easy to access web portal,
- Regional designated point of contact
- Checklist of steps and resources needed to complete an application

2. Application process

- Provide multiple options to obtain and submit an application (e.g., mail, in person, email, online)

3. Interconnection permit processing

- Fast-tracking interconnection application process for systems that have a capacity of 30 kW or less – Anaheim Public Utilities does not require an interconnection application for systems of 30kW or less
- Leveraging technology to provide 24/7 meter access and reduce the need for physical inspection processes
- Real-time communication avenues to deliver notifications in a standardized manner

4. Inspection process

- Model performers do not require a contractor's presence (requires 24/7 meter access) during inspection or permit customers to schedule specific inspection time slots

Source: Desk research, Roland Berger

Arizona has standardized rules for how DER technologies connect to the grid, which is expected to reduce delays and costs

Interconnection best practices – Arizona

Participating utilities

TEP Tucson Electric Power

aps

TRICO AN ENERGY COOPERATIVE

1. Standardization of rules and regulations

> On November 1, 2019, the Arizona Corporation Commission standardized its interconnection rule on how distributed generation technologies connect to the grid

> Experts suggest that the new rule will make the interconnection of distributed renewable generation and distributed storage more streamlined and less costly

2. Encouraging the bundling of energy storage with PV installations

> TEP is rejecting interconnection permits from neighborhoods experiencing "solar saturation" to protect the grid from an excessive amount of power being exported – Only customers who install a battery system to store excess power have their permit approved

> Encouraging customers to purchase energy storage prior to installing a rooftop solar system can reduce the rejection rate and streamline the approval process

3. Interconnection permit processing

> Expedited interconnection application processes are available for systems that have a capacity of 20 kW or less

Source: Desk research, Roland Berger

New York has been a pioneer in setting the standards for interconnection rules and regulations

Interconnection best practices – New York

Participating utilities

- conEdison
- NYSEG
- RG&E
- Central Hudson Gas & Electric Corporation
- Orange & Rockland
- Niagara Mohawk

1. Standardization of rules and regulations

> In 1999, the NY Public Service Commission adopted the Standard Interconnection Requirements (SIR), which established uniform interconnection standards for DER systems

> The rules were updated on January 2017, which **require the developers to demonstrate that they have obtained site control while applying for interconnection**, to clear out a backlog of inactive proposals and allow more advanced projects to be completed

2. Mandating service turnaround time

> The SIR mandates utilities to respond to for an expedited application **within 10 business days** to determine if the application is complete, project is eligible for the expedited process, and whether it is approved for interconnection

3. Interconnection permitting process

> Expedited interconnection application processes are available for systems that have a capacity of 50 kW or less

> Systems up to 300 kW may be eligible an expedited application process provided that the inverter based system is UL 1741 certified and tested

> Utilities are required to maintain a web-based system for providing information on the status of interconnection requests to customers and contractors.

> The SIR mandates that a web-based application process be made available for systems of 25 kW or less

Source: Desk research, Roland Berger

Roland Berger

Massachusetts utilities have been implementing measures to reduce soft costs and time wasted on unsuccessful applications

Interconnection best practices – Massachusetts

Participating utilities

EVERSOURCE

nationalgrid

1. **Transparency & engagement with stakeholders prior to anticipated interconnection delays**
   > National grid failed to engage with the Department of Public Utilities and customers prior to commencing a study that delayed interconnection of solar projects totaling +900 MW
2. **Increasing data sharing from utility companies**
   > Provide a detailed pre-application report for developers to let them know if the area in which they are interested is "saturated" with DERs
   > Reduces time wasted on processing failed and/or uneconomical projects, thus freeing up time to reduce wait times for successful applicants
3. **Develop an incentive scheme to steer developers towards the areas that have less solar PV installed**
   > Improves the chances for approval – Thus, less time wasted on denying applications
4. **Interconnection permitting process**
   > Currently, applications are accepted on first come, first served basis – Prioritizing applicants based on desirable attributes instead could incentivize customers to change their purchasing behaviors and reduce customer pain points (e.g., Prioritizing areas less "saturated" of solar power)
   > Automate the application process (e.g., Launching an online application portal)

Source: Desk research, Roland Berger

Roland Berger

2. Interview Notes

Roland Berger

Key findings from interviews

- > Standard model PPA is hundreds of pages, including pro-utility conditions from all different types of contracts. Everything is laid out in exquisite detail – from liquidated damages to terminations.
- > The RDG PPA is a model contract that has NOT been approved (but instead accepted) by PUC.
- > Everyone at HECO has the same mindset that they can do this work alone. Deep-seated and paternalistic outlook. They are overly careful and conservative. But, they may not know exactly how to do many of these things – how to properly forecast.
- > The nature of the advancements in renewables and DER are all impacting the same areas – causing overload on responsible people and departments within the utility.
- > CBRE Phase II – back to the old complicated PPA as the Renewable Dispatchable PPA – benefits developer as they are not subject to curtailment risk, but many onerous terms and conditions are within the contract.

- > The key issue underlying HECO is its culture – from the top to the bottom.
- > There is a lack of accountability to the regulator and ratepayer. Many people are always deferential to utility because 'utility knows best' is the mantra. Culture is unlikely to improve in the near-term.
- > Interconnection seem to be focused not on eliminating (not managing) technical risks for the utility vs. program benefits and best outcomes.
- > Small projects end up carrying large reliability burdens.
- > CBRE program is at great risk of failure – utility is not invested in its success. PPAs need to be rebalanced so that all the burden and risk is not placed on the developer / subscriber group.
- > Key issues of the RDG PPA are liquidated damages and multiple ways for the utility to terminate the contract.
- > The CBRE tariff, RFP and PPA should all be harmonized around the purpose and viability of the program, not the perfection of the utility's view of energy transactions and system reliability.
- > Long term: T&D Planning needs to be reimagined for the new world of distributed energy and made more transparent for the public. Large, difficult change – is HECO up for it?

Roland Berger

Key findings from interviews

- > HECO is working to improve interconnection issues but many remain.
- > Interconnection costs are always higher in Hawaii than on the mainland (always more on O'ahu vs. other islands).
- > System Impact Study requires detailed dynamic model from inverter manufacturer – unclear what they are doing with that information. HECO always asking for new information and having to rewrite the code/models.
- > Equipment required is not always the most cost effective or has the best functionality.
- > Utility charges of ~10% for PM – no detail or transparency on this line item.
- > 3 line diagrams are required up front in the RFP during screening process.
- > Community outreach is overly prescriptive – utility should not be telling them how and when to do it.
- > Should have regular cadence for renewable RFP until they reach 100%. gives more confidence to developers if they drop out or lose, they can fi the issue and try again.

- > Fixing Interconnection issues will require a wholesale change in how HECO manages the process.
- > Current process is entirely reactionary and for this reason, there is an uncoordinated approach where requirements and standards don't match. Must get to a place where they have an understanding of the conditions of the grid and can proactively communicate this data to developers. Perhaps a full time staff at HECO to do this, instead of hiring out each time.
- > Data requests are far too complex and too much data is requested from developers.
- > Exhibit P – the right to purchase – is too specific. A simple ROFR should do, especially for the CBRE projects.
- > Suggest a fixed interconnection cost, where any costs above the estimate are the responsibility of the utility, not the developer.

Roland Berger

Key findings from interviews

- HECO issues – decentralized organization with EVP for each island – running distinct interconnection processes with different rules and standards for each island.
- Current utility best practices not good enough for the future of high penetration of DER and renewables – smart meters are based on old technology already.

- Sees some improvement and change in HECO's culture – a bit more customer friendly.
- That said, interconnection costs remain breathtakingly high - sometimes killing a project.
- Interconnection issues for C&I and multi-unit solar projects still exist.
- Too much cost is being shifted onto the project. 1) Grid standard are incredibly high - gold plating everything, overengineering and eliminating risk in terms of reliability and 2) shifting regular grid upgrade expenses into the interconnection costs.
- Inefficiencies at the project level – perhaps due to union issues. Too many people charging too many hours. A small army shows up for a small job.

Roland Berger

Key findings from interviews

- > HECO models assume there are no benefits to DER, assumes all old "dumb" inverters. If volt-watt is implemented, it should relieve a lot of the issues that HECO assumes. Available hosting capacity is understated. HECO needs to put a lot of money into modeling secondary circuits.
- > End goal (for developers) is to have volt watt compensated, but for now, would be happy with just having some of the permitting processes accelerated with it – risk of curtailments for end customer.
- > Every HECO truck roll is $500 – many of these visits can be automated or just plain unnecessary.
- > CBRE Phase 2 is at risk of failing: onerous conditions in the RFP, the credit rate is undefined which is a huge value driver, interconnection costs are unknown.
- > Seems to be free-floating information between self build and RFP group, which causes huge concern on the developer side.

Roland
Berger

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