"October 2008 Energy Agreement"

Answers to Questions from the Hawaii Energy Policy Forum

- December 1, 2008 - 12pm - 4pm - Hawaii State Capitol

The Question and Answer session, moderated by Carl Freedman, Regulatory Reform Working Group Chair, addressed the questions below, which focused on clarifying the October 2008 Energy Agreement ("Agreement"). Over 120 specific questions were submitted by Forum members. To ensure the major questions clarifying the Agreement could be addressed in the three-hour session, questions were grouped and not all questions below were asked. However, participants were able to ask any question that they believed had not been asked as well as other clarifying questions. Below is the summary of the questions discussed. Questions asked are in ***bold italics***; questions not asked are also included for reference. Answers from the Signatory representatives -- Ted Liu, DBEDT; Catherine Awakuni, DCA; and Robbie Alm, HECO -- are in *regular italics.*

<u>Opening Statements by Signatories</u>

Robbie Alm: Remind everyone of the context in which the agreement took place; DOE, DBEDT invited the utility to discuss what the challenges are for utilities (fiscal, regulatory, permitting) to get to renewable energy maximization. If the parties, including the CA, came up with some agreement on baseline issues, it would further the progress of renewable energy instead of working on it on a case-by-case basis. Price of oil heightened the need of doing something. Agreement has lots of deadlines in 2009 to address the Governor's need of doing something before she leaves office in 2010. The challenge for the utility is surrendering control on lots of issues and the need to be fiscally sound. PUC isn't included on purpose because of regulatory oversight. Anything legislative is left out of agreement (i.e. tax credits) if it can only be done solely through legislation.

Catherine Awakuni: Starting position for PUC to consider…take something and have a vision to offer that previously has not been provided.

Ted Liu: Estrella Seese is chief of policy and planning and was in charge for DBEDT for agreement. Agreement in part driven by question by Maurice Kaya…why haven't things changed as far as reliance on fossil fuels? Discussion and analysis paralysis & processes that take a long time to implement (legislation). Regulatory system needs to be fixed (numerous dockets, stakeholder process). Need to look at relationship with utility…can't have policies that are continually at odds with utilities. There are slices that can be attacked (regulatory). Yardsticks that DBEDT used to measure: achieve goals that were established (not the Governor's goals) and accelerate the process; we used the best judgment on best info we had available; transparency, deliverables and metrics on achievements; continued points of intervention & participation in the process. PUC and legislature will have lots more discussion on what's in the agreement.

General Questions:

1. The Agreement calls for capital investments of billions of dollars in the State's electrical infrastructure. In what venue will the rate impacts of these investments be examined to determine if they are reasonable? Will this be done by DBEDT, by the PUC, by the Legislature or by someone else? In what specific process or hearing will the rate impacts of the Agreement be assessed?

What is status of the economic analysis and legislative package?
DBEDT:(Liu & Parks) Legislative package is still very much under discussion. Still in the process of having it vetted, discussed and analyzed. Hopefully before the middle of December, the package will be ready for review. We don't have an economic model of the agreement…economic analysis will be a continuing discussion because the factors keep changing. Want to use as much private sector capitol as possible…but need to understand the rate of that impact.

Carl Freedman: Is there a venue where that is going to take place? Where in the process is that part of the puzzle going to be addressed?

Parks: PUC will dictate a lot of that process. Will take place in multiple places; in dockets, at the legislature.

Henry Curtis: Will the economic analysis be private or public?

Alm: Staying with oil is more expensive than investing in capital costs for RE in the long term. The process has been public and will be public. If you're looking for the widest cut, it will be public. Specific issues go to the PUC to determine whether proposals make sense.

2. Is the Booz Allen HCEI scenario analysis the primary basis for assessing the economics of the HCEI initiative? Are the details regarding this analysis available? In particular, how are the CAPEX capital investment costs calculated? Are these net present values of capital expenditures?
3. Have any estimates been made of the capital carrying costs of the capital costs of the HCEI Agreement elements? If so, please explain the methods used to determine capital carrying costs. If not, when will this information be developed and made available to the public?
4. Should the Legislature and the PUC approve of the HCEI Agreement elements prior to a careful examination of the economic and rate impacts of what is proposed?
5. Utility control of the pace and scale of renewable penetration. The system outlined by the accord puts the utility firmly in control of the pace and scale of renewable penetration. Under the current system this has been problematic and not conducive to growth of the renewable share of the State's energy portfolio. In the future envisioned by the HCEI agreement, what level of influence do the parties feel the utility should ideally have on the pace, scale, and pricing at which renewables are connected to the grid? How would it be possible to detect and measure the magnitude of deviations from this 'appropriate' level of control as the HCEI process unfolds?

6. Future of the Renewable Energy Tax Credit is not addressed. The ability to monetize the state incentive is critical to motivating investors in solar electricity producing systems. The agreement does not address any future plans for the credit nor how it will interact with other proposed incentives, such as FIT, in the future. CLARIFICATION: DOES THE AGREEMENT PRESUME ANY PARTICULAR TREATEMENT OF THE FUTURE OF RENEWABLE ENERGY TAX CREDITS?

ARE THE SIGNATORIES AWARE OF THE IMPACTS OF THE NEAR TERM UNCERTAINTY REGARDING CUSTOMER SITED PV AND NET METERED AND THE EFFECTS ON THIS EXISTING INDUSTRY? IS THERE ANYTHING THAT CAN BE DONE TO MITIGATE NEAR TERM NEGATIVE EFFECTS ON THIS INDUSTRY?

ARE THE SIGNATORIES AWARE OF THE IMPACTS OF THE PV HOST PROGRAM ON THE EXISTING CUSTOMER SITED PV INDUSTRY?

7. Near term marketplace disruptions*.* Based on the development timelines for renewables projects of the type emphasized in the HCEI agreement (OTEC, 'big wind,' biofuels), solar PV/thermal will comprise the bulk of the near term contributions to the goals of the HCEI agreement. Yet, the agreement itself engenders substantial uncertainty regarding the financial return for solar projects (via unknown future status/trajectory of FIT, NEM, TOU rates, etc.) thereby undermining the most likely candidate for near term growth in the State's renewable portfolio. Can the parties provide additional clarity regarding returns to potential 2009-2010 investments in order to prevent the market from seizing in anticipation of the unknown outcome/timing of the FIT development and related processes, and rules governing their applicability?
8. Uncertainty and utility conflict of interest regarding PV host program and utility control of interconnection process*.* The PV host program is the only instance in the HCEI framework where the utility will be in direct competition with a specific sector of the renewables industry. Given that this

is the case, there is insufficient information regarding the proposed PV host program to evaluate its impact on the relative and absolute competitiveness of other solar projects. What safeguards do the parties feel would be appropriate to prevent a utility from using its control of the interconnection process to favor its own projects?

9. HCEI undermines commercial/residential solar's current marketplace advantages. In the current marketplace, along with clean energy, solar systems deliver substantial operating cost savings to Hawaii's homeowners and businesses. By raising the cost of solar power to the end user to the retail rate, PV host and other provisions of the HCEI agreement transform DG solar, which is currently an 'operating cost plus clean energy play' for the user/investor, into a pure clean energy play without the operating cost reduction. ***Do the parties understand the negative impact that the HCEI agreement framework could have on commercial and residential solar projects via this DG to centralized generation transformation process?***

Non-utility portion put up by NEM; concern from PV folks is that it's impacting their business. Customers ask what they're going to save, but PV guys don't know what to tell them. Where is PV roof concept? Existing customer who already have NEM tariff? New customers? What is happening in long run?

Alm: Feed in tariff: Popular in Europe, discussed German version in Legislature. Encouraging quicker implementation of RE with fixed rate contract. Started with that idea; seemed to work in Europe. In HI, lot of RE comes in cheaper than base energy – not true for most other places. Do we need NEM anymore (poor man's tariff)? Goal is feed in tariff system. We have a proposal that says in the end, feed in tariff is the way to go. How do you bridge from NEM to feed in tariff? Grandfather existing NEM contracts before feed in tariff goes into effect. We have no intention of disrupting the contracts. Design a good feed in tariff after input from everyone. March 2009 deadline in place to address accelerating the uncertainty re: NEM.

Freedman: Are NEM issues going to be included in the FIT docket… are we expanding the docket re: feed in tariff?

Alm: Have to ask the PUC.

Freedman: Time of Use NEM. To what extent are you saying that this is all future stuff that's going to be addressed by the PUC or is being addressed now?

Alm: Trying to be consistent with everything. Time of use rates should apply. Everyone gets advanced use metering. Feed-in tariff and NEM. Everything should come to the same place. Pricing programs should be opt out instead of opt in, in order to get things moving. Very few states have feed-in tariffs, so HI needs lot of input in order to design good program for HI.

Freedman: Anything we can do to mitigate the near term issues for NEM so their businesses could move forward? Would signatories be willing to meet with the PV industry folks to address near term impacts on the industry?

Signatories: Yes— willing to meet with PV folks.

Warren Bollmeier: Can leave up to customers as to what treatment they want? Leave current customers where they're at? Seems more elastic than what is proposed.

Parks: Want the best consumer benefit. Open to further discussion.

Freedman: In the agreement, one element is PV host program. Quoting from one of the questions for comment: "This may be good and/or bad for the PV industry. The up side is that the utility will be on board with moving PV technology forward. The downside is that the Utility has a distinct advantage in that it understands and controls the current/future circuit infrastructure, which ultimately limits the amount of PV that can be installed. The utility also controls the modifications/limitations required by Rule 14 already in place. If the utility is "in the market" it can favor its own projects being installed versus other PV suppliers"

Alm: Will be proposing PV host program by 3/31/09. One assumption is that utility *will own it, which is not true. Some customers want the utility to be the broker. Need to ensure some fairness. Not a question of whom you leave out, but that everyone should be in. No CHP projects came in because the developers didn't want to assume fuel risk.*

Curtis: Is it the belief that the utility, not the energy efficient utility should handle it?
Alm: This wouldn't replace any activities or any programs done by energy efficient programs. One of the tenets is that more is more; HECO should be obligated to add on to the operations, not supplant them

Jody Allione: Would PV host sites be eligible for FIT?
Alm: PV host will probably come in after FIT at PUC.

Mark Duda: PV Competing with utility and other DG within the 15% circuit level cap is the concern; could spell quick end to the PV market.
Alm: Agreed to take off system caps because problem doesn't occur at system level; occur at circuit level. Circuit cap applies to HECO DG and any other facility on the circuit. Have pilot project to determine whether 15% is the correct number.

Riley Saito: PV host program similar operationally to solar water heater program?
Alm: If solar company has customer they're working with, HECO won't get involved. HECO would play intermediary role. The agreement says we could go in and own, but the challenge is that the capital that is needed is huge; may happen but too much capital outlay and too much other work to do. HECO will focus on advanced metering and transmission infrastructure for capitalization not PV on roofs.

Freedman: Summarizing, it sounds like HECO is not trying to take over PV industry and is willing to sit down and talk with PV about how everything's working out.
Alm: All grid connected renewables count for RPS. If we are going to meet RPS we need

the existing PV industry.

DBEDT & CA: Not walking away after agreement is signed. Will still do what's in the best interest of the consumer.

WHAT THE AGREEMENT SAYS ABOUT RECS VS THE EXISTING STATUS QUO. WHAT IS THE CURRENT TREATEMENT OF RECS? WHAT WOULD BE THE TREATMENT UNDER THE TERMS OF THE AGREEMENT?

10. RECs. The utility has made known its desire to claim all RECs from all interconnected DG. Due to the certification process for RECs, this eliminates the State's REC market. While it is reasonable for the utility to negotiate over RECs as part of compensation in IPP and other arrangements, why is the default that the utility receives RECs on all interconnected systems? Further, there seems to be no basis for using regulatory authority to enforce such a system.

Freedman: What is current status quo re: RE credits?

Alm: No market at this point; right now it's a ratepayer asset. Discussion still going on re: RECs to determine what's going to happen locally and nationally. Military is allowed to count RECs towards renewable goals. Talking with military on how to get the RECs to them. Current federal law provides that any RE that happens on a military base cannot be counted towards the state's RPS.

<u>Cover Letter</u>

1. Page 2. What exactly does "traditional sales-based" company mean in terms of generation ownership and revenue expectations? This document indicates that the utility will continue to build and own projects, albeit renewable energy, but it will not be paid on sales.

2. Page 2. How do the Parties envision that the utility's revenue basis will be calculated?

<u>Section 1. Wind Power for Hawaii</u>

1. ***Page 4, paragraph 1-5. Do the Parties envision a competitive bidding process for development of windpower for transmission of electricity to Oahu from Molokai or Lanai? If so:***

    a. ***Why not consider windpower from both islands, and***
    b. ***Why not open the RFP to all interested bidders, including all renewable technologies***

Comments: We believe the first attempt to interconnect all our islands failed in part due to the apparent reliance on only one renewable source (geothermal) on Hawaii Thus, we not believe it is wise now to promote interconnection of the islands utilizing only wind power. There was also a proposal by MECO to site a coal power plant on Molokai with interconnecting cables to Maui and Lanai. Again this proposal, which was opposed the people of Molokai, would have relied on only one source of electricity.
Alm: Competitive bid process already took place; got non-conforming bids covering wind power from NI to Oahu; already have bidders to deliver it.

2. ***Page 4, paragraph 1-5. Have the Parties really taken a close look at all alternatives, including an all-out effort on DSM measures, offshore wind and OTEC, that would allow Oahu to stand-alone? If not, why*** not? Please explain in detail.
    Parks: Can't cut deal on OTEC today. Cable can be used to stabilize all systems.
    Alm: Cable technology and pricing has improved to the point where HI should look at cabling all the islands together. Once cable is in, using RE wherever it occurs in the island chain is huge.

    Page 4-5. On page 4, it is clear that the developer (s) must assume the risks associated with the development of their project (s). On page 5, it appears that the state will assume all the risks for the development of cable project with assistance from HECO and the developers. That said, ***are we correct in assuming:***

a. ***Taxpayers will fund the cable project, with possible federal and private sector cost shares,***
b. ***Developers are at risk for all development activities prior to the approval of the cable project and construction has been initiated?***
   Alm: Second answer is yes. First part is it's still to be seen how it's to be paid for. Only part of the equation that doesn't work is that private sector money is going to pay for it. Will definitely check on federal grants.

3. Page 4-5. ***Do the Parties have an estimate of the time required to secure approval and funding for the cable project?*** This milestone does not appear to be included Exhibit A.
   Alm: Go as fast as we can on everything we're doing. Sit down with administration this month to figure out how to go forward. Developers are responsible for their own development and permitting risk.

4. ***Page 4, paragraph 6. Do the Parties support a premium payment to IPPs for energy storage components, if required by the utility interconnection study, e.g. for power smoothing?***
   Alm: Payment yes. Should they be paid extra for it? Don't know why they should be

5. Page 5, paragraph 7. Regarding the implementation of infrastructure enhancements and additions, including a cable system, the Parties propose recovery of approved costs via the CEIS. Do the ***Parties propose renaming and/or modifying of the proposed Renewable Energy Infrastructure Program ("REIP"), Commission Docket No. 2007-0416, to become the CEIS?***
   Alm: One will supplant the other.

6. Page 5, paragraph 7. ***Do the Parties propose that the costs for the cable project would be born via the CEIS by the ratepayers of HECO and MECO?***

   Freedman: Is CEIS a forever surcharge or would it be folded into rates at each rate case?
   DCA: Taking the REIP process and renaming it; taking it on a case by case basis; examining to determine whether surcharge should be approved.

   Freedman: Summarizing next three questions, it sounds like the payment and operation of the cable system is yet to be determined. *Signatories agree*.

7. ***Page 5, paragraph 7. What kind of reimbursement do the Parties envision that a third party transmission company entity would receive?***

8. ***Page 5, paragraph 7. Is a tolling system envisioned?***

9. ***Page 5, paragraph 7. Is this to be an Independent System Operator ("ISO") type structure?***
   Alm: Operate a franchise wide grid and make sure the standards are in place for all islands. Would allow any island to back up other islands.

10. Page 5, paragraph 7***. Who determines the hierarchy of the cable use, if additional energy is available on neighbor islands***.
    Alm: Open question. Same kinds of standards apply here that apply to managing the grid in general.

11. Page 5, paragraph 8. Do the Parties envision that rate recovery could be used to finance the undersea cable and other T&D upgrades in addition to a tolling system? That way both suppliers and users would pay for the system.

12. Page 6, paragraph 10***. Did the Parties consider penalties related to milestones and operation commitment dates by the wind companies that***

are directly or indirectly affected by HECO's inability to proceed in a timely manner?

DCA: There are a number of milestones for ourselves to monitor utility rather than general milestones; i.e. filings with PUC.

13. Page 6, paragraph 11. Based on the experience with the Hawi Renewable Development and Tawhiri windfarms on Hawaii and the Kaheawa Pastures wind farm on Maui, it is clear that there are ***grid operational issues*** to be resolved in order to expand the use of windpower on Hawaii and Maui. ***How do the Parties propose to resolve these issues,*** including a timeline for each island? Please explain. ***IS THERE A TIMELINE?***

    Alm: Look at sections 1 & 3, studies are underway and significant. HI is going into ground that's not covered anywhere else in the world (standalone grid). Strong commitment from NREL & GE; funding from DOE and utility. Some results in 2009 and major results in 2010 as far as cable coming on line. Grandfathered and upcoming RE projects included.

14. Page 6, paragraph 11. Do the Parties believe a cable system will help stabilize the Maui County and Oahu grids? Please explain.

<u>Section 2. Renewable Energy Commitments</u>

1. ***Page 6-7. Is there a conflict between the state renewable energy commitments and the new avoided cost methodology adopted under Commission docket no. 7310? If not, why not?***

   Alm: In old RE contracts we paid avoided costs; one RE developer protested proxy method and we switched to production simulation method in Docket 7310. No further contracts like that can be signed under HI law. All new contracts can't use avoided costs as the basis.
2. Page 7, paragraph 5. Re this statement: HECO "will not add any new fossil fuel-based generation over 2 MW beyond those already approved by the

Commission or under construction without equivalent megawatt hour retirements:"

  - Do the Parties believe the use of smaller (2 MW) fossil fuel generators would be used in "emergency" situations, and
  - Why couldn't these smaller generators be biofueled?

3. Page 7-8. Are the Molokai and Lanai Big Wind projects "grandfathered" projects under the proceeding of the Competitive Bidding docket (No. 03-0323)?

4. Page 7-8. Reference comments on Section 1, page 4, the two projects to compete to win a PPA for the "Big Wind" project? Either way, do the Parties support a RFP open to all renewable sources? If not, why not?

5. Page 8. Regarding the Military DG (100 MW), would these be military-sited projects selected via a RFP (s) issued by the military?
6. Page 8. Why is the proposed Waikoloa Wind Power LLC – 10.25 MW wind/battery storage project, which was waived from competitive bidding (Docket No. 2008-0061), not included in the list of HELCO projects?
7. Page 9, paragraph 1. Did not the County vote this WTE project down? If so, why is the project still on the list?

8. Page 9, paragraph 1. How would decisions be made on reduction of fossil fuel use? For example, would the reductions be based scheduled from the units with the highest heat rates and hence highest energy cost?
9. Page 9, paragraph 1. Does HECO intend to implement Pumped Hydro Storage ("PHS") to facilitate integration of additional renewables? If not, why not?

10. Page 9, paragraph 1. For example with PHS, would not it be possible increase the amount of as-available renewables on HELCO's grid well in advance of 2023. Please explain the delay?

<u>Section 3. The Technology of Inter-Island Renewables</u>

Will the economics of the inter-island cable system be examined in the existing IRP process or in the new Energy Scenario Planning process?

Alm: Existing IRP just suspended in past few days so we're onto energy scenario planning.

Liu: We will not go forward with the cable system before there is an economic evaluation in a public forum.

1. Page 9, paragraph 1. ***Please clarify the role of the proposed true" cost/benefit analysis in the decision-making process for interconnecting Oahu to Maui County. Specifically:***
    a. ***Will the "true" cost/benefit analysis include alternatives to a cable system?*** If not, why not? See also our comments on Section 1 (page 4).
    b. Do the Parties believe interconnecting the islands will improve system reliability? If so, how?
    c. ***Will a "true" cost/benefit analysis include a possible carbon tax or cap and trade system?***

       Alm: Yes.

       Curtis: Do you envision cable as 3 separate lines as is the case for the transmission lines (levels of redundancy)? Looking at network of cables between the islands?

       Alm: Will be included in studies. Yes, network of cables. Thought is to go in with one large capacity cable system instead of going back and doing it again. Cable to the BI is envisioned as phase 2; then go onto to issues on how to integrate. Maui County to Oahu is target one and achievable in much shorter time frame.

       Parks: Things that you do to improve the grid should benefit the entire system, not just one project or island. Utility needs to look at interconnection and making sure the system works as a whole.

<u>Section 4. The Solar Opportunity</u>

1. Page 11-12, paragraph 3. Referencing the Decision and Orders ("D&O") of the DSM docket (05-0069), ***all HECO DSM programs are to be transferred to the Public Benefits Fund Administrator***, correct?
   Alm: Yes.

2. Page 11-12. Please explain ***why HECO is now to implement PAYS®.***
   Alm: Not designed to be exclusive to HECO. Similar to PV installations.
3. Pages 11-12, point 3. Solar water heating PAYS-like scheme. How will this be funded? Demand for solar water heating is exceedingly high as evidenced by the rebate program running out of money in 2008. What measures are being taken to ensure that this program will be adequately funded?

4. ***Page 12. Do the Parties believe the PAYS® goal could/should be higher than 2,500 solar water heating systems a year?***
   Alm: This is the # of units/year that HECO agreed to as a minimum.

5. Page 12***. Did the Parties consider coordination of a more aggressive PAYS® program with other incentive programs to install solar water heating systems on virtually 100% of our single-family homes?*** If not, why not?
   Parks: Yes, possibly included in legislative package.
6. Page 12. It is not clear why a more aggressive DSM effort has not been proposed. For example, ***did the Parties consider an "all-out effort" to achieve to convert virtually all of our buildings (residential, commercial and government) to "zero net energy" by 2030?*** If not, why not? For example, with such an all-out effort, would not this be the more cost-effective approach in the near term, avoiding more expensive new generation facilities?
   Parks: Yes, possibly included in legislative package.

7. Page 12, paragraph 4. Why is wind not included as part of the renewable DG to be facilitated under the Rule 14H tariff?
8. Page 12, point 4. What is expeditiously integrating mean? Currently Rule 14 has 4 to 6 month delay in completing interconnection approvals?

9. Page 12, paragraph 6. Do the Parties envision that a customer would have a choice between a feed-in tariff and net metering? If not, why not? Or do the Parties intend to replace net metering with feed-in tariffs and standard interconnection agreements?
10. Page 12, point 6-7. These two sections merge the use of feed-in tariffs and Net metering while introducing a TOU rate spin. How will the PV industry and customers be able to calculate the payback/economic benefit of systems being installed while this is being developed?

11. Page 12, paragraph 7. Net metering, as ruled by FERC, is a power exchange agreement. Please explain the rationale for this proposal, making more like a PPA. For example, if the purpose is to encourage delivery of energy to the grid, would not a feed-in tariff be a better approach?
12. Page 12, paragraph 7. Please explain the rationale for requiring net metered customers to switch to time-of-use net metering with excess energy payments, especially for zero net energy homes
13. Page 12, point 7. It seems that the elimination of NEM is at least contemplated in the first sentence of this section. Is this possible without legislative action? Is it the parties' understanding that the PUC can eliminate NEM under its ability to 'modify' NEM as granted during the 2008 legislative session?
14. Page 12, point 7. The status of currently net-metered systems is ambiguous. Will these systems be required to move to TOU billing? Will they be required to move to FIT rate system?
15. Page 12, point 7. Will NEM and FIT co-exist? For which, if any, classes of customer generator?

16. Page 12, point 7. Will NEM availability for residential systems remain an option?
17. Page 12, point 7. In the last sentence, which begins "The parties agree that net metering…" What does this mean? What is the intent of including it here?
18. Page 12-13. Is not the proposed PV Host Program a type of green tariff, which could be of potential interest to customers that do not want to invest directly in PV (or wind) systems?
19. Page 12-13. However, the proposal appears to be substantially similar to HECO's proposed CHP tariff that was allowed under the DG docket (No. 03-0371). Subsequently, HECO withdrew its proposed CHP tariff. How is PV Host Program different?
20. Page 12, points 8-13. Comment: This may be good and/or bad for the PV industry. The up side is that the utility will be on board with moving PV technology forward. The downside is that the Utility has a distinct advantage in that it understands and controls the current/future circuit infrastructure, which ultimately limits the amount of PV that can be installed. The utility also controls the modifications/limitations required by Rule 14 already in place. If the utility is "in the market" it can favor it's own projects being installed versus other PV suppliers
21. Page 12-13, point 8. Why is a PV host program deemed necessary? What steps will be taken to ensure that ancillary rules associated with things like interconnection will not be used to favor utility invested PV host facilities at the expense of alternative PV host facilities and/or non-PV host facilities? On projects where the utility is a bidder, what third party oversight can be set up to make sure the process is fairly conducted?
22. Page12-13, point 8b-c. How does a 'competitively procured', third party-owned system under the PV host program differ from an IPP? What is the "standard rate" noted in Point C and how does it differ from the FIT rate?
23. Page 13, point 8d. On what basis will the PUC establish PV <u>system</u> costs?
24. Pages 12-13, points 5 & 12. What is the difference between these two points? They appear to substantially overlap with the latter mentioning CSP.

Section 6. Avoided Energy Cost Contracts

1. Page 16. Is there a preferred method to de-link existing IPP payments from fossil fuel? For example, would payments be based on:
    a. A levelized price lower than avoided cost,
    b. A feed-in tariff formula, or
    c. Another approach?

Section 7. Feed-in Tariffs

1. Entire section, p. 16. Comment: This is a great step forward to move toward levelized rates for Hawaii in the future. The question is ***will there be a rate matrix that separates various technologies by system size? Will it be time sensitive in relation to the installation date? Will the rates be extended out over a 20-30 year period? Are systems under the feed in tariff subject to the circuit limitations?*** *Alm: Currently being proposed; end of Dec. should provide clarification on first 3 questions.*
2. What is the reasoning behind the March 2009 target date for completing the feed-in tariff docket by the PUC?
3. Should the PUC carefully examine all aspects of the feed-in tariff approach or should this be a quick approval based on the prior agreement of the signatories?

4. Page 16-17. It is not clear that DG can be installed on the customer's side of the utility meter under whatever FIT scheme is put in place. ***Can the parties clarify the fact that customer side DG is not covered by the FIT?*** *Alm: It will depend on the ultimate design of the FIT.*
5. Page 16. The system described is not exactly a FIT in the sense that it does not set a rate and let producers compete in the marketplace to beat it by whatever margin they can manage. By setting the FIT price relative to cost of production, the proposal inherently favors some technologies relative to

others. ***Do the parties plan to establish FIT quotas for different technologies?*** *Alm: Yes, being looked at.*

6. Page 17. Please explain the phrase "incremental rents paid to renewable providers in the short term."

   Page 17. ***Are feed-in tariffs expected to replace the current process for competitively bidding for new renewables? Or will feed-in tariffs be implemented within the competitive bidding process?*** If so, please explain. *Alm: When PUC is done with FIT, should relook at competitive bidding to see how those two work together. May remain for large increments of generation.*

   Bollmeier: How are you developing FITs? If using outside consultants, are they going to be retained throughout the life of the tariff? *Alm: Yes to consultants in helping to develop FIT.*

COULD YOU CLARIFY HOW THE 10% FEED-IN TARIFF IN RATE BASE PROVISION WOULD WORK… DOES THIS MEAN THAT THE UTILITY WOULD EARN ITS PERCENTAGE RATE OF RETURN ON THE 10% INCLUDED IN RATEBASE?

7. Page 17. Please ***explain rationale for the "agreement in principle that 10% pf the utility's energy purchases under feed-in tariff PPA will be included in the utility's rate base through January 2015***."
8. Page 17. To be clear, would item 4 apply only to new PPAs implemented after the feed-in tariffs are in place (requested Commission action by June 2009 as indicated in Exhibit A)?
9. Page 17. ***Are feed-in tariffs going to be moot with the Commission's order to adopt a new methodology for calculation of avoided energy cost (Reference docket no. 7310)?*** If not, please explain how they would co-exist.
10. Page 17. ***Will HECO offer utility-owned sites for third Party development for feed-in-tariffs?*** If so, how would those proposals be evaluated?

11. Page 17. ***Will HECO be allowed to develop their own sites, subject to the same feed-in-tariff and criteria?***
12. Page 17. ***Will the state offer its facilities and land for all Parties to proposed projects under feed in tariffs?***

    DBEDT: State will offer sites. HECO will look over all its sites to determine what's available.

13. Page 17, first bullet***. What entity or entities will design the FIT on behalf of the PUC?***

    Put on table; up to everyone to come together.

14. Page 17, second bullet. ***What are the FIT rate classes envisioned by the parties***?

    Still working it out.

15. Page 17, first sentence after bullet points. ***Please provide clarification of 10% calculation***.

    Allow utility to get return on rate base on that 10%. Trying to get amount that would be best at this point, to allow the PUC to determine more reasonable rate.

    Alm: 10% would provide strong motivation for utility to more aggressively execute RE.

    Freedman: Has anyone penciled out 70% HCEI imputed debt issue? *Alm: The agreement tries to address the imputed debt issue by putting all improved IPP contract payments through surcharges. The impact could be significant as one rating agency currently imputes debt in the amount of $600 million (50% of the net present value of all obligations under the IPP contracts) on HECO's books.*

16. Page 17, last paragraph. ***What is the justification for eliminating intra-governmental wheeling?*** Intra-governmental wheeling would complement the HCEI package rather than being redundant with it.

    Agreement was to suspend the docket for one year. DCA: Resources is a huge issue; more productive to get everything else online given limited resources of DCA. If FIT is at the right level, it would automatically be addressed. Alm: Same thought as competitive bidding. Feed-in-tariff is a form of competitive bidding and can be evaluated quicker than RFPs.

17. Page 17, last paragraph. Why suspend the Wheeling Docket? This should be a perfect marriage with applying the feed in tariff to install large scale RE projects to offset government purchases of fossil fuel generated electricity.

Section 9. Renewable Portfolio Standard (RPS)

1. Page 18. (1st Bullet): Please explain the rationale for why no changes would be made to our RPS law until after 2014 with respect to energy efficiency, demand response and renewable displacement technologies. For example, why not define an "Energy Efficiency Portfolio Standard" to be implemented now by the Public Benefits Administrator with appropriate adjustments to RPS?

CLARIFICATION: WHAT IS ASSUMED IN THE AGREEMENT REGARDING THE TIMING OF AN ENERGY EFFICIENCY PORTFOLIO STANDARD? IS IT TRUE THAT NO CHANGES TO THE RPS WOULD BE MADE UNTIL 2014? Alm: Should go ahead ASAP. Agreement not meant to delay that. Count EE in order to meet RPS by 2010.

Mark Duda: RECs currently require 3rd party certification in order to be tradable. Utilities are able to count them, so that's why there's no market. *Alm: Can only count green credits once, so ratepayer is hurt if PV developers use the credits* *to make money and utility cannot meet its RPS goals. In addition, the ratepayers have paid for the renewable energy so it's unfair to them not to get the credits.*

Bollmeier: Why not draw the line at the customer meter and have public benefits administrator take care of everything on customer side. *Alm: HECO should be responsible for its portion of RPS. Will probably occur at 2010 when it kicks in*

2. Page 18. (8th Bullet): Will the reevaluation include electric load requirements from a rail transit system (or its alternative)?

I WOULD POSE THE FOLLOWING QUESTION BY ASKING GENERALLY WHAT THE AGREEMENT SAYS ABOUT THE TREATMENT OF MILITARY DG WITH RESPECT TO THE RPS AND RECS.

3. Page 18. (9th Bullet): There a number of potential options for treatment of military DG:

a. Military DG projects (where all the energy is consumed on-site) would count towards the utility's RPS, per our current RPS law, correct?
b. If a military DG project exports power to the grid, the utility would pay for energy or capacity as delivered. The exported energy would count towards the utility's RPS, per our current law, correct? However, RECs are not needed for RPS compliance, correct? Note; as with classic PURPA transactions, the utility purchase only energy and/or capacity, but not green attributes.
c. However, military entities are obligated to purchase RECs to comply with their RPS, correct?
d. Did the Parties consider how the utility and military entity could to claim credit for the renewable energy? First, the energy would count towards our RPS law. Second, the military could purchase RECs from the producer in order to comply with their RPS.

<u>Section 12. Energy Efficiency</u>

1. Page 21-23. Why do the Parties not discuss the concept of "zero net energy" buildings (including residential, commercial and government) as part energy efficiency or the broader category of DSM measures?

Section 14. Advanced Metering Infrastructure

1. Page 24-25. The opening sentences of this section seem to indicate that having an advanced meter will not be mandatory and hence TOU billing will not be mandatory. Is this the case?
2. Page 24-25. It is not clear if NEM customers be required to install advance meters or if this will be optional? Will the rules differ for existing NEM customers vs. those installing systems since the HCEI announcement vs. those installing systems after the potential adoption of AMI/TOU rules by the Commission?

Section 15. Pricing Principles and Programs

1. Page 25, paragraph 1. Please explain how the Bonbright Principles, which date to the 1960s, apply to the HCEI challenge.

2. Specifically, are they consistent with increasing competition in the supply of electricity and energy services, and alternative utility profit structures?

Section 16. *Meeting the Military's Needs*

1. Page 26, Entire section. Do circuit limits apply to Military sited projects?
2. Page 26, paragraph 1-3. Please clarify the second sentence: "The Parties agree to allow the utilities to meet the military energy service needs through competitive or other service contracting methods as long as the utility can provide such services in a way that benefits rather than compromises other ratepayers." Specifically:

- The military will not solicit renewable energy services via a RFP as planned, and
- Does this mean the military can buy only from the utility and not from IPPs or ESPs?

3. Page 26, paragraph 1-3. Please explain the contractual options that are to be considered. Specifically:

  - What is Enhanced Use Leasing and how would the utility implement this option, and
  - As noted previously, please justify the utility supply of customer-sited DG, given its monopoly power

Alm: The basic intent of Section 16 is: Whatever the military wants, it gets. At the point that the military connects to the grid, we will work with them. What the military does on their bases is their business.
Parks: Technical issues do apply.

Section 19. Net Energy Metering

1. Page 28, first sentence. Since only system wide caps are mentioned as being removed does the 100kW per meter remain place?
2. Page 28 last paragraph. Does this mean that until the LVM are identified and trigger modifications to be consider the entire grid penetration of DG/NEM is capped at 15%?
3. Page 28. Will there be a grandfathering of NEM system prior to some date, milestone, etc. such that grandfathered facilities will not be required to convert from NEM to FIT? If the parties envision requiring existing NEM agreements holders to convert, where does the authority for mandating this lie?
4. Page 28. What constitutes a "<u>new</u> net metered installation" for the purpose of determining whether a system is required to convert to TOU billing?

5. Page 28, first bullet. There is no reason offered for the 15 percent limit on NEM generation at the circuit level. What is the reason for this limit? Assuming that concerns are technological (as implied by the 12kV standard) why do limits not vary with other technological properties of the circuit, such as upgrades intended to handle reverse power flows, or with customer sited technologies to limit back feeding, such reverse power relays?
6. Page 28, first bullet. What will limits be for circuits greater than 12 kV?
7. Page 28, paragraph 1. (1st Bullet): it appears that the Parties view the 15% limit on 12 kV circuits as an "initial" limit and subject to review. Is this correct?
8. Page 28, paragraph 1. Do the Parties see the proposed NEM Pilot Program for customer-generators larger than a 100 kW as an initial approach to test the 15% limit criteria?
9. Page 28, paragraph 1. (Last Sentence): Will Rule 14H be reviewed periodically or is it considered permanent until such time that the utility proposes to amend or withdraw the tariff?

Section 22. Green Contracting

1. Page 29. Please elaborate on the conclusion that "green attributes" should belong to the ratepayers?

2. Page 29. For example, other states, such as California, have concluded that the renewable producers have initial right to "green attributes." Was this approach considered? If not, why not? If so, why not adopted

Section 28. Decoupling from Sales

1. Page 33, section 1b. Regarding ongoing capital investments, how will CEIS investments impact HECO's overall capital structure and standing with respect to Wall Street. For example:

a. As CEIS investments increase, will HECO have to decrease and/or phase out generation investments,
b. Given a., will HECO forgo investments in new generation in order to pursue CEIS investments?

Section 29. Clean Energy Infrastructure Surcharge (CEIS)

1. Page 34, entire section. How will the surcharge work in relation to the "decoupled" rate schedule? The CEIS covers all the new transmission, capital, infrastructure, recovered cost stranded, etc. Decoupled rates will cover the in place "business as usual" operation/cost of the utility. What is the incentive for the utility to actually change how they do business?

Section 31. Preferred Stock/Hybrid Securities Offering

1. Page 36. Was the issue of the payments to IPPs being considered as "imputed debt" by Wall Street discussed?
2. Page 36. If so, is this considered a major issue to be addressed?
3. Page 36. If so, what are the potential solutions?

Section 34. Federal Law and Rules

1. What specifically is the basis for exempting the State from PURPA?
2. What is the goal of exempting the State from PURPA?
3. Page 41. Aren't the stated reasons for proposed exemption from PURPA already addressed in the Competitive Bidding Framework? If not, why not?
4. Page 41. Did the Parties consider any unintended consequences of securing an exemption to PURPA? For example:

   - Existing QFs would lose their PURPA rights, and
   - Competition would be decreased without the ability for IPPs to seek PPAs under PURPA as currently allowed current options for exemptions and waivers under the Competitive Bidding Framework

Section 35. Greenhouse Gas (GHG) Issues

1. Page 42. Regarding the proposed suspension of consideration of RECs, would the Parties consider the following:
    a. Use of RECs for military compliance with their RPS, as noted above, and
    b. Confirming initial producer RECs ownership, which would allow their marking or RECs and thereby lower their price proposal in competitive bidding processes and/or adjustment of feed-in tariffs?

Section 37. How We Stay on Track

1. Page 44. Do the Parties view this agreement as a "living document" and will be reviewed periodically? If so and:

    - How frequently, and
    - Will the document be subject to review by all interested Parties?

Other questions from the audience

Riley Saito: Rule 14? What changes will come about?

Alm: Rule 14 adopted in May 2008; utility should move as expeditiously as possible in interconnection requests. Doesn't have a specific timeline; but if stalling or not moving it will move it along.

Curtis: PURPA. Anyone planning to change PURPA and unintended consequences?

Alm: Request HI exempted from PURPA. Intent is to prevent loopholes that allow fossil fuels/coal to gain foothold in HI.

Bollmeier: Living document? If so, how to review and revise?

Parks: Lay milestones…quarterly or monthly. No set date or time yet.

Alm: This document is only a part of HCEI.

Sandie Wong: Many parties tried to intervene in decoupling docket but utility filed protest of objection. Is the document only meant for DBEDT, DCA & HECO?

Alm: On decoupling, we see this as the exception that proves the rule. On other HCEI-related filings such as feed-in tariffs, we have not opposed intervention. As a consistent practice, the utility has objected to broad intervention in rate cases and we view decoupling as a rate case matter.

Freedman: Role of DCA vis a vis this agreement…DCA is tasked with representing consumer interests. As DCA, are you obliged to stand by the terms of the agreement or are you free during the course of the agreement to take in more information and possibly change your position?

DCA: We have a limited amount of information and wanted the ability to, if we did learn something that was radically different than what is in the agreement, have the flexibility to go back to the parties and discuss further. It is a living document and there are ongoing discussions. We're free to amend the agreement.

Freedman follow-up: If the DCA did want to change its position would it have to get the agreement of the other signatories?

DCA: We would first look to get agreement from the signatories according to the terms of the agreement.

Lynne Ebisui: Energy efficiency section. Re: gas issues included in the section: How will gas utility be treated? Section 12 – Energy efficiency. *To be discussed at a later date.*