

a. General Announcements

9:00 – 9:20 am

- a. ETO: New Guidebook available; Budget information

Jed Jorgensen: introduced the ETO's Small Hydroelectric Permitting Handbook. He covered ETO's revised process and output with forms for enrolling hydro projects and requests for funding.

Funding will be a 50% cost share for pre-project work, up to 40K total – grant writing; feasibility; design assistance; FERC and interconnect preparation; etc.

This info will be on their website.

ETO Budget for open solicitation: Name will possibly change. Draft Budget - 2010 1.5M from PP, 1.7M from PGE; 2011+ 550K from PP and 1.5M from PGE. These are below what they have been in the past, and things may change in the future regarding disbursing of funds.

- b. ODOE: Reorganization information

Karen Chase: ODOE's new Financial Services Section is physically moving to its own office and combining efforts to become more effective in delivery of services: BETC, SELP, ARRA

- c. Others

Mary Grainey: OWRD – Nov 17th – public hearing on Public Fees for relicensing; may get bigger as time goes on; review panel will look at those fees. Opportunities for comment will go at least to the 17th.

b. Low Impact Hydro Institute – criteria changes

9:20 – 10:00 am

- Fred Ayer (LIHI Exec Dir.)** will discuss certification process and information changes; give examples of regional opportunities

Fred Ayer: See attached Outline.

Their criteria are very "FERC-centric". Rely heavily on expertise of state and federal resource agencies, and this has worked well so far.

Certifying since 2001. Now 44 projects in 22 states. Some that have obtained certification have obtained a premium for their electricity; some do it for the publicity. Well-received by industry: 5 year certification; many are hitting their recert – every one wants to be recertified.

Challenges:

- Size criteria – some states want it based upon size rather than environmental criteria.
- Small operators and/or Older facilities – hard to get a handle on all the regulatory stuff and don't have resources; so, these take longer to process. So, the better job developer does, the quicker the process goes. Exemptions are also more problematic to deal with.

New license issued by FERC have been very well done and complete and are easier for LIHI to deal with.

- Fees are too high – They have dropped the fees; now at \$1600 fee plus 15% annual of process fee (\$375/yr) for smallest projects. Small is under 0-20.4 GWh of generation. Over that is \$2500 (about 6 MW).

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Small sized plant they've certified: 250 kw. Some between 250 and 1 MW. Almost all projects are dams. Just certified a project at the end of a water treatment facility in Boston Harbor (5 MW). Less than 5 feet in height – not considered a dam; a diversion instead (FERC regulation for exemptions). Storing water is the issue – water degradation.

Proposed criteria generated a lot of comments (from more than 20 entities). The criteria will be ready sometime in the late Winter, Feb or so, 2010.

New Criteria: Want to make sure they are in line with others on incremental hydro. This allows for more inclusive and more open door approach.

Also, want to be able to deal with things like Settlements. Want to be able to define them, and describe the attributes of them. They've interpreted them to mean that an agency signature means this is the most stringent determination.

Need to make determinations about grandfathering projects. Thinking that this will go for one full term. If you have 2 years or less on original certification, you'd be allowed to go one more term – so really 7 years.

Don't want to wait as long to revise criteria.

Advice: Do upfront homework before you file. Answer the questions! Provide a copy of water quality certificates, for example.

One of the program's features they've tried to maintain: if you're thinking about filing, call them to do pre-application work. Some do this for a year before they file. LIHI will work with you and give you a staff-perspective opinion regarding the project.

How long to go through certification? Used to take about 4 months; now more like 6 or more months.

c. Introduction to International Hydropower Association's "Draft Hydropower Sustainability Assessment Protocol" 10:00 – 10:05 am

Karen Chase, ODOE: Quick summary of the IHA's protocol to ensure participants know about its existence.

Break

- d. **Farmers Conservation Alliance – Farmers Screen** **10:15 – 10:50 am**
Julie Davies-O’Shea (FCA Exec Dir.) will provide information on FCA services, their fish screen and its utilization

Julie Davies-O’Shea: Farmers Irrigation District – known for the “farmers screen”. They developed a screen that worked for them; patented and licensed to FCA. Since 2006 FCA has taken it to market. Still working on getting the word out about the product.

Offers field trips to seeing the 6 screens that they have in place.

Had Rotary Drum Screens – very common. These were constantly getting clogged and someone had to perpetually clean them out - \$90K/yr plus loss of hydro. In 1996 flood – all 13 points of diversion/rotary drums were ripped out. They didn’t want to simply replace these diversions which weren’t really working for them to begin with – the debris screen problem. Endangered species Act introduced fish protections. State of Oregon has 70K diversions, est’d 55K are unscreened. ESA required screens and no one was building them. 5 cfs and under (90-95% of diversions). Costs and permits for screens were unwieldy. ODFW – est’d \$3-5K per year to maintain for 5 cfs diversion.

FID – went to Agencies to come up with new screens after 1996 floods. They started researching horizontal screens and others. About 10 years and \$2.5M – about 2000 they came up with design that worked. Goal: use physics instead of electricity. Didn’t want air bursts or moving parts...

Davenport screen on Hood River (85 cfs)

Water moves quickly over the screen, and percolates through it slowly. Tapered walls keep horizontal velocity the same on exit as on entry. They need flow all year around, or turn the screen off. Working with NMFS to determine lowest water flow rate to still run and protect fish. They are in final stage to become an approved NMFS criteria screen. They can go down to 2.5 cfs and up to 400 cfs. NMFS has a lowend criteria flow. Now have 17 screens in ground and 7-8 hydrologic tests. Need a foot of depth over the screen.

Can double-screen up to 32 cfs. Trying to get screen costs down and also utilize a bolting system rather than concrete for remote locations. So, installation costs vary, but savings come on O&M. Modular’s are now going in without their support.

Introduced the “Navigator” – excellent publication summarizing renewable energy incentives – grants, tax credits, other funding, State, Feds, and others – available for home, farm, business.

- e. **PUC UM 1396 Discussion** of issues – lower power purchase rates, avoided cost restructuring, and potential effects on small hydro **10:50 – 11:40 am**

Vijay Satyal, ODOE: PURPA (Federal), Contracts, Renewables – Understanding the process

Utility Miscellaneous (UM) 1129: Talked about implementing PURPA in Oregon. Less 10 MW – production, delivery (quality of power differs) of power – avoided costs and how it affects IRPs. Once you decide on IRP, it affects the avoided costs. Every 2 years – avoided cost filing.

ODOE and PUC worked together for last 4-5 years to make renewables affordable.

PURPA 1978 – Provide a market for e produced by small power producers and cogenerators. OR PUC through Order No. 05-584: encourage economically efficient development of QFs; ensure utilities pay rates equal to that they would have to pay to purchase/produce that power from a QF; notion of avoided costs – opportunity costs.

UM1129 Setting standard contracts for facilities producing 10 MW or less. Phase 1 let to: a 10 MW threshold for standard contracts; manufacturers nameplate capacity; Max term of 20 years with 15 years of QF selecting fixed pricing and market rates for last 5 years.; Use avoided costs

20 year contracts were specified to average out over the long term the typical minimum costs needed to set up a project.

Last 5 years at market rate: can be fluctuating flow; so utility exercises resource balancing and can go out and buy the electricity needed.

Avoided Costs – Differing ways to assess:

- Forward trading prices of natural gas and its' relationship to electricity prices (off and on peak)
- Based off only “variable” costs of operating generating facilities – whether you're resource sufficient/deficient, the cost of a “proxy” natural gas CCCT – combined cycle combustion turbine - is used as it would be the “alternative” to your QF power.

Issues: based of only variable costs of existing operating facilities; 2 year fling. Now, we're in a recession – and NG prices are lower – which are a “base” to firming avoided costs. If a QF cannot provide firm power, power is purchased at market prices. ODOE notes that additional QF pwer for capacity reserves be valued. PUC also sided with ODOE – use historical approach, but add fixed and variable costs to pricing AC.

Current Issues: Quality of QF power; Firm versus non-firm power; IRPs to use differing NG forecasts; NG? or anything else?

1136: how do we determine if a utility is deficient in its resources? ODOE can intervene on the utilities' forecasts. But PUC decided to not settle on a single prices for all utilities.

Hawaii has ruled to decouple the AC from the price of oil (or NG). Going to FITs – paying above AC and retiring undesirable plants. So, not based on AC at that moment. Developers cannot anticipate.

If you're developing in Oregon, you need to know what your prices will be. Utilities will argue for lowest avoided costs. Small developers individually cannot be as expert as utilities. Several small developers/districts has hired someone to represent them to the PUC. Utilities are trying to lower AC and make a complicated situation for interconnection. Proposed rates have dropped 48% for the next 5 years. State has an obligation not to raise rates above market.

The utility has to buy your energy at the published rate; they don't have to buy the certificates. Won't be well-served in Oregon to have a bundled package. You can sell much more out on the market

Under existing QF – selling energy (not necessarily renewable) to the utility. And, right now, we have enough power. Utilities say they're good until 2020 for RPS requirements. Utilities can use up to 50MW of their own resources – so they've fulfilled their quota. IRP and AC are supposed to be synced. AC filing after IRP is acknowledged (and every 2 years). So current AC prices went into affect, we'll see a revision in Dec 2009. Then, when IRP is acknowledged in Jan – triggers another AC revision in Feb/March 2010. So, should we change the process???

In latest OPUC staff filing – on 1442 – they disagree on opening up AC pricing, but if separate generating case to be opened, they'll relive 1129.

- f. **Discussion of Green Tags** – How they work for small hydroelectric projects; Their markets; Valuation; and more **11:40 – 12:20 pm**
Kip Pheil, ODOE

Lunch – distribution

- g. **Discussion and preparation for FERC's Small Hydro Technical Workshop**, December 2, 2009, in Washington D.C. **12:40 – 2:00 pm**
Steve Hocking, FERC

Steve Hocking: Described the format of the Dec. 2nd FERC Commissioners' Small Hydro Workshop. We will all be able to view this Workshop via their Webinar. Ken Homolka, ODFW and also on the Oregon Hydro Working Group's Core Team, has been invited to be on one of the 2 panels in Washington DC. We discussed what, if anything, he may be able to do to represent the SHWG on that panel.

Importantly, there will be an open comment period following the 12/2 Workshop. Jed has offered to coordinate efforts to determine if and what we as a group may want to submit.