Renewable Energy Advisory Council Meeting Notes

February 4, 2015

Attending from the council:
Bruce Barney, Portland General Electric
Diane Broad, Oregon Department of Energy
Cindy Dolezel, Oregon Public Utility Commission
Kari Greer, Pacific Power
Suzanne Leta-Liou, Atkins
Frank Vignola, Solar Monitoring, University of Oregon
Dick Wanderscheid, Bonneville Environmental Foundation

Attending from Energy Trust:
Chris Dearth
Sue Fletcher
Matt Getchell
Mia Hart
Jed Jorgensen
Betsy Kauffman
Dave McClelland
Dave Moldal
Elaine Prause
Thad Roth
Peter West

Others attending:
Ken Dragoon, Flink Energy Consulting
Evan Elias, Oregon Department of Energy
Shawn Foster, Portland General Electric
Kira Hill, Green Energy Institute
Nate Larson, Green Energy Institute
Alan Meyer, Energy Trust board
John Reynolds, Energy Trust board
Amelia Slusher, Green Energy Institute
Nick Waltman, Green Energy Institute

1. Welcome and introductions

Betsy Kauffman convened the meeting at 9:30 a.m. The agenda, notes and presentation materials are available on Energy Trust's website at: www.energytrust.org/About/public-meetings/REACouncil.aspx.

2. Preliminary year-end results

Betsy provided an overview of 2014 preliminary annual results for energy-efficiency and renewable programs. Results reflect the best available data at this time, and may shift after the release of the annual report to the Oregon Public Utility Commission on April 15.

> Standard solar achieved 140 percent of goal for 2014 and three custom projects were completed for hydropower, geothermal and wind technologies. All Oregon Public Utility Commission benchmarks were met. Total generation was 2.39 aMW, falling short of the 4.49 aMW goal. This shortfall was due to several projects with completion delayed into 2015 and 2016 and one cancelled biopower project.

Cindy Dolezel: At what point do we say we can no longer delay a project?
Betsy: If there are legitimate reasons for the project's delay and we're confident that the project is on track to be completed, we will amend the contract. If the project fails to hit an important milestone or if there are substantial changes to the project, we will not amend the contract.
Jed Jorgensen: Consideration is almost always on a case-by-case basis.

3. Other Renewables strategic plan

Betsy highlighted overall themes for technologies funded in the Other Renewables program. Although the technologies served by the Other Renewables program differ, there are similarities in the barriers faced, the effect of a challenging market and the ways that Energy Trust works with projects. Commonalities across strategic themes include placing greater focus on projects with multiple benefits, looking for projects that can net-meter, engaging stakeholders, using project development assistance and capacity-building to build the pipeline, and applying lessons learned from existing projects to inform future projects.

Dave Moldal provided a brief history of biogas energy projects that Energy Trust has supported, including market factors and strategies to expand the pipeline of biogas projects in the future.

Dave Moldal: Over the last 10 years, Energy Trust has supported 11 biogas energy projects located at wastewater treatment plants, dairy digesters and food waste processing facilities. Of the 20 wastewater treatment plants that are producing biogas from anaerobic digestion and located in Portland General Electric and Pacific Power service territories, nine are generating electricity through cogeneration. Electricity generation is often secondary to the core responsibility of the wastewater treatment plant and there is strong competition for biogas from transportation fuel initiatives. Ultimately, successful biogas energy projects require on-site energy champions. Coming up, the Biomass Producer Collector Tax Credit, HB 2449, legislative concept could extend business tax credits.

Bruce Barney: How would that work?
Dave Moldal: The credit would be sold.

> Technological innovation to monetize nutrients has the potential to change the playing field. Food waste regulation and anaerobic digestion paired with water reuse systems could also expand this market. There are opportunities to maximize generation at existing biogas energy projects and to share best operating and management practices. Future biogas support should focus on projects that net-meter and those that secure co-digestible feedstocks.

Dick Wanderscheid: Landfill gas projects do not have above-market costs, but there are more landfills in Oregon than the six completed projects. If developers of landfill projects see a market, they should move that forward. Would that create above-market costs?
Dave: We’re not seeing those projects come in.
Peter West: There are regulatory barriers. Thad Roth would know more.

Alan Meyer: Strategies are well written. There are more opportunities for dairy, yet it’s not a primary focus. What are the difficulties?
Dave Moldal: I can list six dairy operations in Oregon with 2,000 to 3,000 cows that are not presently using anaerobic digestion to produce biogas. The average dairy size in Oregon has about 600 cows. This is an economies of scale challenge; small dairies simply do not produce enough manure. Dairy-based biogas energy projects are hampered by insufficient incentives. Also, development opportunities are more attractive in other parts of the country.
Betsy: This is about net-metering versus low qualifying facility, QF, prices. Biogas projects that can offset onsite load through net-metering are more economically viable.
Jed: Small family farms are less attractive from a developer perspective.

Diane Broad: We need to encourage sharing across sectors and focus on co-benefits. There’s potential for less than well-defined benefits for dairies.

Bruce: Can you expand on the current and future market for fats, oils and grease, FOG?
Dave Moldal: Gresham is receiving tipping fees for FOG at 9 cents per gallon. They turned away a lot more volume of FOG than they need. Adding FOG doubled their production of

biogas. Clean Water Services Durham had eight to 10 respondents to their FOG request for proposals. There is a lot more FOG available in the market but not enough FOG receiving stations.

Chris Dearth presented on the strategic plan for biomass. Energy Trust has participated in about 18 feasibility analyses and two biomass projects over the past 10 years. There are four segments of the biogas market: onsite generation; stand-alone generation projects, which are not likely in the future due to low QF rates; combined heat and power, which is expected to be a major segment for Energy Trust; and liquid biofuel production with generation from waste process heat. Challenges surrounding biomass projects are low QF rates combined with high feedstock costs, and numerous uncertainties pertaining to forest policy, unstable economics for the timber industry and unreliable long-term biomass supply. There is a large amount of biomass built up in our region and it remains a challenge to economically manage the overgrowth. Going forward, strategies for biomass projects include an aggressive outreach strategy, deepening our understanding of the market and technology, cooperating with the Statewide Wood Energy Team and other market actors, and remaining opportunistic with potential projects.

Alan: Can we sell power into PGE and Pacific Power service territories?
Chris: Yes, although it adds wheeling costs.
John: Utilities are not pleased to wheel in projects located outside of their service territory.
Chris: We will participate if project managers are willing to move power into Energy Trust service territory.

Chris presented a summary of the strategic plan for wind. He provided a brief history of the wind program, conversion of Energy Trust incentives to performance-based incentives and the formation of the Interstate Turbine Advisory Council to authorize and support reliable turbines and turbine companies. Distributed wind in the United States was generally stable up until 2013 when there was a dramatic decline in additional wind turbine construction. Similar numbers are expected for 2014.

Bruce: On the distributed wind graph displayed, how do you separate utility-scale distributed wind?
Chris: This chart of distributed wind includes what we would consider utility scale. In this case, distributed wind is dependent on how and where the turbines provide the power.

> Wind is experiencing several challenges. There have not been cost decreases like those experienced in the solar market. The Investment Tax Credit is expiring in 2016, creating an uncertain environment. Trade allies do not have the resources to market wind in a small market. Permitting obstacles remain in several Oregon counties and utility incentives are more favorable outside of the U.S. Strategies include engaging with industry players and partnering with trade allies as requested. Energy Trust is no longer proactively seeking projects and will respond opportunistically to potential projects.

Nate Larson: What does it mean to be a bad actor in the wind turbine market?
Chris: The turbine or company does not perform as the company claims. Energy Trust narrows the field to those considered to be good partners and provide reliable technologies.

Dick: Are developers focusing on Europe due to the high feed-in tariffs?
Chris: Yes, high feed-in tariffs are making wind projects more economically viable in European countries.

Diane: Are we seeing activity in refurbishing decommissioned turbines from 1980s to 1990s?
Chris: A Nevada state agency did provide incentives for refurbished turbines, but it hasn't been done in Oregon to my knowledge.

Jed presented on the strategic plan for geothermal, provided a general overview of the geothermal program and addressed market factors for geothermal projects. Those market factors include high upfront risk and costs, challenges in developing projects under 20 MW and low QF prices. It is difficult for Energy Trust to play a role in geothermal, and opportunities for outreach are minimal. Energy Trust will continue to engage with market players and developers, provide Project Development Assistance and maintain an opportunistic approach to funding projects. In the future, technological advances in underground imaging may improve the success rate for well drilling, and there could be a greater government presence in developing small projects.

Alan: You got it right with this form of triage. It's not ratepayer-driven and there's low opportunity.

4. Report on challenges faced by small energy generators related to transmission scheduling and costs

Energy Trust studied the unanticipated costs and challenges faced by several renewable energy projects transmitting power across Bonneville Power Administration transmission lines, such as transaction costs, scheduling and difficulties accommodating fractional generation. Ken Dragoon, principal at Flink Energy Consulting, presented the findings and recommendations.

Ken Dragoon: There are three unanticipated costs associated with transmission for new market entrants. Local utility costs for connecting to Bonneville Power Administration's system, scheduling and e-tagging costs ranging from hundreds to thousands of dollars per month, and scheduling of point-to-point transmission. Transmission schedules and e-tags are required to be submitted in 1 MW increments and Bonneville Power Administration requires 24-hour response for scheduling entities. One recommendation to work around scheduling fractional generation is alternating scheduling requests by increasing and decreasing transmission by 0.5 MW.

Alan: Energy generators have to pay for transmission 100 percent of the time, even though they're only contributing one-third of the time?
Ken: True.

Ken: Based on the tariff structure, it's more cost-effective to schedule low generation in the beginning of the month and higher generation at the end of the month, even though the generator could only be delivering 0.1 MW. Recommendations from the study are to share resources and experiences, pool scheduling and e-tagging services across a group of small generators and consider negotiating with the utility to accept short-term firm transmission. Work can be done with Bonneville Power Administration to develop support for small generators and ensure additional costs associated with transmission are understood for those delivering outside their local utility territories.

Jed: Are there repercussions for not fulfilling the scheduled generation?
Ken: None were identified.

Alan: Good job identifying the complexity of these challenges. This is an area where we could help lower barriers for projects looking at wheeling. There could be opportunity to create a group of experts to consult.

Thad: We try to highlight the costs and challenges of transmission with potential projects and include these costs in the assessment of above-market costs. We encourage customers to use us for Project Development Assistance. We offer guidance and resources to deal with uncertainties.

Dave Moldal: Can you expound on the costs faced by the JC-Biomethane project? Generally, what costs do they realize on a monthly basis?
Ken: Costs of each project are available on page 11 of the report, including costs associated with local transmission, scheduling services with e-web, 24-hour response and ancillary services. These projects are concerned about large setup costs, and some had concerns with software for e-tagging and requirements for scheduling.

Dick: The distributed wheeling fees don't really exist. The utility has to come up with this number when confronted with it. JC-Biomethane was downsized because the utility was charging high transmission fees. Did you identify distributed wheeling fees for each project?
Ken: These fees weren't included in the report. It's the predisposition of the utility and isn't regulated under Federal Energy Regulatory Commission, FERC.
Dick: There are interesting ways to get around it based on where they're placed the system. We could help developers select sites to increase cost-effectiveness.

Betsy: Is there a role for the OPUC or legislation?
Ken: The OPUC and Bonneville Power Administration are not involved with consumer-owned utilities. They follow FERC's rules. There is still potential for discussions about policies and best practices. Consumer-owned utilities want distributed generators in their service territory. I recommended staying away from a regulatory approach.

Diane: Are the zero costs associated with the Middle Fork project on page 11 correct?
Ken: They are not zeroes. Those numbers have been redacted.
Jed: Pacific Power was paying for the e-tagging costs in this case, while PGE did not cover these costs.
Bruce: I have no historical knowledge on this issue, but to venture a guess, this is based on risk to the utility. If long-range generation planning fell through, this would be a cost to ratepayers.

Ken: When scheduling for the month, does it matter how often you change the schedule throughout the month? This is worth discussion.
Dick: There is a workgroup at Bonneville Power Administration that could discuss how to deal with these challenges for small projects, under 3 MW.

5. Public comment
There was no additional public comment.

6. Meeting adjournment
The meeting adjourned at 11:00 a.m. The next Renewable Energy Advisory Council meeting is scheduled on March 11, 2015.