EnergyTrust of Oregon, Inc.

RENEWABLE RESOURCE ADVISORY COUNCIL
Notes from meeting on May 21, 2008

Attending from the Council:
Thor Hinckley, PGE
Robert Grott, Northwest Environmental Business Council
Lori Koho, OPUC
Frank Vingola, UOSRML
Doug Boleyn, Cascade Solar Consulting
Carel DeWinkle, ODOE
Joe Reinhart, OSEIA

Attending from the Board:
John Reynolds, Univ. of Oregon

Others attending:
Troy Gagliano, EnXco
Steve Anderson, Evergreen Engineering
Russ Wright, SunEdison
Anne Gravatt, RNP

Attending from the Trust:
Lizzie Giles
Peter West
Betsy Kauffman
Erin Johnston
Brian Thornton
John Volkman
Alan Cowan
Thad Roth
Jed Jorgensen
Sue Meyer Sample
Tara Crookshank

1. Welcome and Introductions

Peter convened the meeting at 9:37 am. The April notes were adopted without change.

2. Open Solicitation Project: West Linn Hydro

Betsy Kauffman brought a micro hydro project in West Linn to the RAC for feedback. The city of West Linn is proposing to install a micro-hydropower project totaling 5.1 kilowatts (kW) at the site of one of its pressure reduction valves. The project is expected to be completed in October, 2008.

This would be Energy Trust's first small hydropower project using the pressure within a municipal water system to generate electricity. This "urban microhydro" market is one we would like to develop. This is an excellent opportunity to learn about these kinds of projects and their costs. West Linn is also showing great leadership by committing to this project.

The city of West Linn operates several pressure reduction valves in its water system to reduce water pressure to a point where the water is usable in homes. After an analysis by an Energy Trust consulting engineer, the valve near a Metro yard debris station along Willamette Falls Drive was determined to have adequate flow and pressure to generate hydropower. There was also adequate room in the vault at this site to install the turbine and electrical connections.

Upfront capital, installation, and permitting costs for the project are expected to total $59,232, including a contingency fund.

The table below summarizes our comparison of project revenues and expenses and calculation of above-market costs.

NPV electricity revenue	$21,165
NPV BETC Passthrough	$17,777
NPV total Revenue	$38,942
Minus	
NPV Total Design & Construction	
NPV Operations Expense	($59,232)
NPV of $500/year spare parts fund	($5,624)
contribution	($4,687)
NPV Total Project cost	($69,543)
NPV Net above-market costs (total revenue minus total project cost)	**($30,601)**

Energy Trust is proposing to pay an incentive of up to $33,967 upon commissioning and depending on final project bids. The proposed incentive has a present value of $30,601 which would cover 100% of the above-market costs of the project. The incentive will be paid upon project commissioning. Energy Trust will take title to 100% of the tags for the project over 20 years.

The project will run year-round, producing an annual 40,208 kilowatt-hours of electricity which will be sold to Portland General Electric under a standard QF contract.

Staff supports this project and is recommending that Energy Trust provide up to $33,967 in funding.

John Reynolds asked for the size of the contingency fund. Betsy responded that it is about 20%, or $9,000. John commented that projects similar to this one had come before the RAC in the past. Peter responded that there have been a few, but the market lacked experience to bring the projects to fruition. Betsy added that there were additional issues with the two previously considered projects.

Robert Grott commented that Energy Trust is recommending support of this project because it would be a model to other projects, but he isn't clear about how much opportunity exists. Betsy said that every municipal water system in PGE territory has been contacted by Staff with an offer to co-fund a feasibility study and receive assistance with applying funding from the state. Two have accepted and three others are seriously considering moving forward. As cities develop sustainability plans, this becomes a more attractive opportunity.

Steve Anderson said that they will likely find 10 or 20 favorable sites with the infrastructure to develop the project successful. West Linn is a small project, which contributes to its higher cost. However, most of these future projects will be larger and therefore more cost-effective. There are also opportunities to use existing pumps as a turbine generator, which would dramatically reduce the cost.

Joe Reinhart asked what West Linn is contributing to the project. Betsy replied that they must put in the entire amount upfront, and will receive the BETC pass-through and Energy Trust funds upon completion, leaving them with around $10,000 net out-of-pocket costs. It was designed to give the city around a seven year payback. Joe asked if this might be making the

expectation for return too high for future projects. Steve responded that the most valuable lesson for other cities will be that this is a viable opportunity when they are putting in pressure reduction valves. Peter added that the return is in line with other commercial projects. Carel DeWinkel said that ODOE is very supportive of this project and looks forward to the experience for future project.

Peter asked for approval from the RAC. There were no dissenting votes. They will move forward on contracting with West Linn.

3. Proposed Increase to the Solar Budget

Kacia Brockman explained that Staff is proposing a shift of $1.5 M of PGE and $1 M of Pacific Power money from the uncommitted Community Wind program into the solar budget to support large solar activity. As was discussed at an earlier RAC meeting this year, the Community Wind funds will not be spent this year due to a lack of turbine availability. $1.3 M would be left in the Community Wind budget for PGE and $650,000 for Pacific Power should opportunities with used turbines become available.

This budget shift would impact program performance goals. Had the money been spent in the Community Wind program, it was forecast to achieve approximately 1.15 aMW, whereas in solar, it will achieve .34 aMW. However, staff has previously reported that all the community wind projects are stalled and there appears to be no prospects to secure turbines.

Currently, 96% of the solar budget in PGE and 107% in Pacific Power is committed, and Staff has a long list of additional projects that would move forward if the funds were available. However, the commercial market for solar is very volatile at the moment. Even with this additional money, staff expects a 25% attrition rate, and it could be higher. Nevertheless, if the money is not moved into another program, it will not be spent and there will be no generation.

Nearly 80% of the currently committed solar budget is involved in third-party owned projects. The third-party model is valuable because it allows entities, such as cities and non-profits, to host solar energy systems they would not be able to afford it otherwise. This is providing enormous economic and development opportunities in Oregon.

Peter repeated that by shifting the funding, we are taking advantage of an opportunity to deliver generation where there would be none (if the funds were left in Community Wind) and support projects we would otherwise not be able to support. The funds that are left in the Community Wind budget are sufficient to support a project should an unexpected opportunity arise.

John asked why used wind turbines are coming on the market and where they are coming from. Alan said that projects that were built 10 or 20 years ago are being repowered. Smaller turbines of 400 or 600 kW are being replaced with 1+ MW turbines. The removed turbines are being refurbished and sold at a significantly reduced cost. And, more importantly, they are available.

Anne Gravatt asked for clarification on the remaining $1.3 M in PGE and $650,000 in Pacific Power. The RAC members supported the budget change.

4. Third-party Ownership Issues with Pacific Power

Kacia briefed the RAC on several concerns Pacific Power has raised with regard to third-party ownership model. Last week, a request was made by the OPUC for information on Energy Trust projects' use of the third-party model to assist them in responding to several issues being raised by Pacific Power. The first concern, raised over a month ago, was that third-party owned

systems should be treated as Energy Service Supplies (ESS), and the second was that these projects should not be eligible to net-meter.

Eighty percent of the commercial solar electric budget is involved in third-party owned projects, making these concerns from Pacific Power very detrimental to Energy Trust's projects. There are twelve solar trade allies promoting this model to their customers. There are at least 23 active projects moving forward that would be affected by any changes.

Lori said that there are three issues. The first was treatment as an ESS. An additional question came up regarding territory distribution. If someone else is generating power in their territory, is that a violation? And lastly, there is the net-metering issue.

The OPUC believes that the ESS and net-metering concerns can be decided by a Commission ruling. Right now, the Department of Justice has been working with Honeywell, who may file a petition on this issue. However, Honeywell may decide that this is more expense than it is worth and pull out of Oregon.

The OPUC would like to settle this issue as quickly as possible. The hope is that this will not need to go into the next legislative session. Speed is of the essence. Because of the economic and development impact of this concern, there is a strong motivation to move as rapidly as possible.

Carel asked why net-metering was even an issue. Kacia commented that if the system owner was forced to act as QF and sell directly to the utility, the host would not actually be purchasing clean power, which may not meet their motivations for investing in the project in the first place. Peter added that there are financial drawbacks as well in having to pay property taxes on the normally exempted equipment and delayed contracting on the QF and interconnection.

Robert said that this has implications beyond solar. He is working with microhydro and biomass projects using this model that would be damaged by not being able to net-meter or use third-party ownership models.

Anne asked Lori if Pacific Power has filed anything formal. Lori said they have not, but the way in which is has been presented it must be addressed.

Carel said that this should be made a legislative concept, if it hasn't already. Lori replied that it has.

Brian asked how quickly the Commission can move on a declaratory ruling if Honeywell moves forward. Lori said that she is unsure, but she would expect at a minimum several weeks.

Peter asked if the Governor's Office has been contacted. Lori responded that they are aware of the situation.

Kacia asked if projects in PGE territory can move forward since PGE has not raised these concerns. Lori said she cannot provide guidance. It comes to down to whether the investors feel the risk is too great or not.

5. Proposed Rules for Small Generator Facility Interconnection

Alan Cowan gave a presentation on the current draft of the Oregon PUC's proposed Small Generator Interconnection Rules. Small generators are deemed to be 20MW or less.

Under the 2005 Federal Energy Policy Act the Oregon PUC is required to implement "uniform technical standards, procedures, and agreements for interconnecting generators" based on IEEE 1547 standards. Under the act the PUC was to have made a determination on or before August 8, 2007. Though the process was begun on June 20, 2006, the determination deadline has passed.

The draft rules are based on the MADRI Model Small Generator Interconnection Procedures and propose 1) technical standards, 2) the application process, 3) the interconnection process, and 4) the relationships between parties (the utility and the applicant).

The technical standards are based on IEEE 1547 and IEEE 1547.1. The Underwriters Laboratory implementation of IEEE 1547 is labeled UL 1741.

The application process classifies the interconnection by on the project size and the complexity of the interconnection. Based on those classifications a project may be directed into a fast-track or full study process. Fees and timelines are also determined by the project classification.

The interconnection process sets guidelines for the process from construction through to operation, including witness testing, commissioning tests, inspections and certificates of completion to the implementation of the interconnection agreement.

The relationships between parties define insurance needs, dispute resolution guidelines, the relationships of other services, such as standby power, backup power, and distribution charges, as well as a process for curtailment and disconnection of the project.

The proposed rules are applicable to projects under 10MW that wish to connect to a public utilities distribution or transmission system, that are not subject to FERC requirements, and that are not seeking a net metering solution. The proposed process is not retroactive, but would capture existing projects at the end of their contract life.

The proposed rule creates four project classification tiers:

- **Tier 1**
  - 25 kW or less
  - Lab-tested, inverter-based interconnection equipment
- **Tier 2**
  - 2 MW or less
  - Lab-test or field-tested interconnection equipment with documentation from previous Tier 4 application
- **Tier 3**
  - 10 MW or less
  - Must not export power beyond point of interconnection
- **Tier 4**
  - 10 MW or less
  - Does not qualify or fails to meet Tier 1, 2, or 3 requirements

Alan does not think we will see many projects in Tier 1 as most will choose net-metering at that production level. Tiers 2 and 3 have specific screens to filter projects. Those that do not fit those screen pass into Tier 4.

All Tier 4 projects undergo a full study process. The process starts with a scoping meeting to determine whether the utility should perform a feasibility study or proceed directly to a system impact study, a facilities study, or an interconnection agreement. Any or all of the studies may be skipped.

Timelines for the study process are proposed as follows:

- Application Receipt – 10 days, notice of complete or incomplete
    - 10 days to complete application if required
    - 10 days to schedule scoping meeting

- After scoping meeting
    - 15 days to approve application if mutually agreed no issues or minor upgrade -OR-
    - 5 days to provide feasibility study agreement
        - Agreement is based on a scope of work, reasonable schedule, good-faith, non-bind estimate of study cost
    - 15 days for applicant to execute feasibility study agreement
    - Complete study (no timeline, could be weeks or months)
    - Study is provided to applicant within 5 days of completion

The process then repeats for each study, as necessary.

If facility upgrades are needed as a result of the study, the utility may hire third party contractors or the applicant may hire the contractor if it is agreed to in writing by both the utility and the applicant.

The utilities are required to keep for two year records related to the number of completed applications that were received, the time required to complete the review process for each application, and the reasons for approval or denial. In addition, the utility must keep contract records for all interconnected customers, including documentation from studies.

The utilities must provide an annual report to the PUC including:

- Number of completed applications received
- Number of interconnections completed
- Types of facilities and nameplate capacities
- Location of completed facility by zip code
- Reasons for approval or denial
- For Tier 3 and 4 approvals: basic telemetry configurations
- For Tier 4 : interconnection facilities required and estimated costs

Alan noted that while these record keeping requirements are a good step, they don't necessarily give enough data to know if a utility is intentionally trying to delay projects. To understand if that is happening it would also be of benefit to know the initial estimated costs of feasibility studies and the actual contracted costs of those studies.

The rule also proposes regulations for metering and monitoring of generation equipment above 3MW in capacity. The utility is required to install, maintain, test, repair, and operate the equipment. The applicant is required to pay for it. The utility and the applicant may agree to modify the telemetry rules if they choose to do so.

In cases requiring arbitration of a dispute, either party may petition the PUC for arbitration. The PUC shall use an administrative law judge unless workload necessitates and outside arbitrator. Appeals to the PUC are not allowed.

There is an Administrative Law Judge's Workshop on the rules on May 28 at 9:30am at the PUC building in Salem. Public comments will be taken at a hearing on June 11 at 9:30am at the same location.

Carel commented that in terms of costs, the telemetry packages are a good value in these draft rules. But if the utilities want to delay things they will be able to do so. More reporting would be good to provide proof that a utility is trying to obstruct projects from moving forward.

Alan agreed, noting that a long range goal would be to have a cost-effective telemetry system available for use here in the NW.

Betsy asked if there are areas in the rule that could use improvement.

Alan commented that having a standardized rule for all utilities will be a good thing.

Peter explained that having a common standard means that projects can plan what to do. It's better than the current system, which he described as "a black box." He believes the ability to have an outside consultant to speed the study process up is an important feature that has been left out of the rule.

Alan noted that Energy Trust's early comments to the PUC asked for that change but it was not put into the rule.

6. Public Comment

Peter asked for any further public comment. There was none. He adjourned the meeting at 11:30am.