EnergyTrust of Oregon, Inc.

**RENEWABLE RESOURCE ADVISORY COUNCIL**
Notes from meeting on April 18, 2007.

***Attending from the Council:***
Thor Hinkley, PGE
Justin Klure, ODOE
Jeff King, NW Power & Conservation Council
Lori Koho, OPUC

***Attending from the Trust:***
Elizabeth Giles
Erin Johnston
Alan Cowan
Betsy Kauffman
Peter West
Kacia Brockman

***Attending from the Board:***
Alan Meyer, Weyerhaeuser
John Reynolds, University of Oregon

***Others attending:***
Dave Tooze, City of Portland
Jon Miller, OSEIA

## 1. Welcome and Introductions

Peter convened the meeting at 9:30 am. The March notes were adopted with one change from Lisa Schwartz. In an attempt to conserve paper, Peter asked if RAC members would be comfortable not receiving copies of the previous meeting's notes in the packets provided at each meeting. All materials, including notes, will continue to be provided electronically within the week prior to the scheduled meeting. RAC members agreed to this change.

## 2. Legislative update

Justin Klure presented an update on the 2007 legislative session. The Governor has five energy legislative proposals. HB 2210, the Biofuels bill, sets a renewable fuel standard for Oregon tied to in-state production of fuel. Also included are tax credits for producers and collectors of the raw material for biofuels. There is also an income tax credit for consumers of E85 or B99 blend biofuel.

HB 2211 is the increase in the Business Energy Tax Credit (BETC) from 35% to 50% for consumers and increases the project cost limit from $1M to $2M. HB 2212 is the Residential Energy Tax Credit (RETC) change that allows residents to claim multiple tax credits for measures in the same year and increases the maximum credit for wind and fuel cells. These house bills have passed the Senate Ways and Means Committee and are moving onto the Senate Finance Committee next week. From there, they go to the floor for a vote. The bills are moving very quickly and accepting no changes to the content or language.

SB 232 allows state agencies to develop renewable projects on state land. SB 838 is the Renewable Energy Standard, which had it first hearing on Monday.

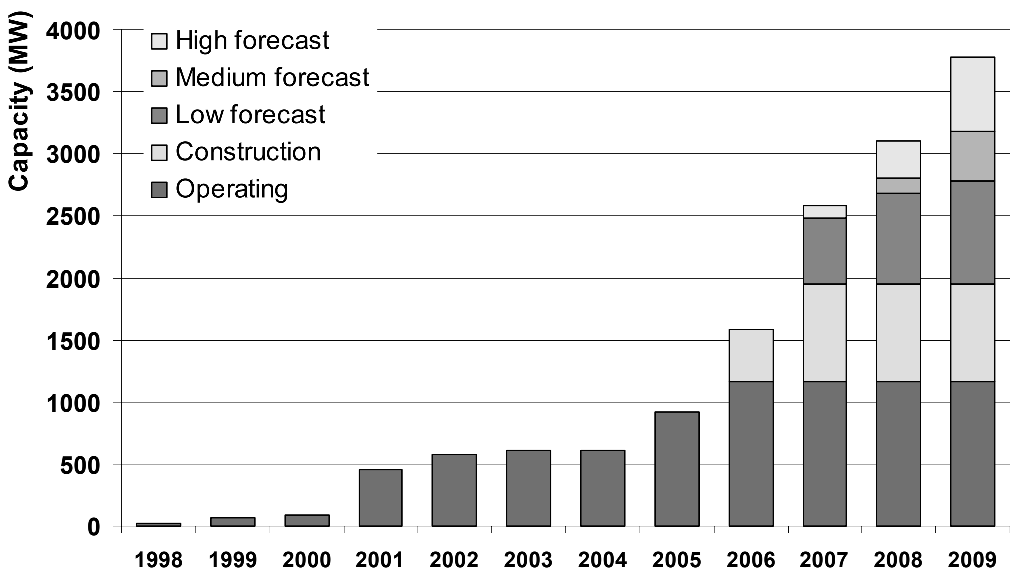
Several other bills involving energy and climate change have also been proposed, including several relating to wave energy. HB 2844 creates an enterprise zone three miles off the coast of Oregon to allow counties to exempt wave energy projects from property tax. HB 2925 exempts wave projects under 5MW in the R&D phase from the state permitting process. SB 875 requires bonding for wave devices to ensure derelict wave power equipment is decommissioned properly. SB 581 is an appropriations bill for the Oregon Innovation Council that is proposing to fund a variety of industry driven innovations. One, for example, is a biomass/biofuels research institute.

Though there are no bills drafted, concepts exist for climate change policy. One is being referred to as the Climate Change Integration Act and would establish a global warming advisory committee and track emissions. It also has a research component that would establish a climate change research institute. Another concept sets a baseline emissions standard for natural gas power plants. Hearings will begin next week on these climate change packages.

John Reynolds clarified that HB 2211 allows homebuilders to claim the value of the residential tax credits for renewable energy systems.

### 3. Wind Integration

Jeff King presented on a recently completed effort by the NW Power and Conservation Council on wind integration action plan. This was a joint effort with enormous input by parties throughout the region. It was supervised by a 23 member steering committee and an over 80 member technical committee. The motivation was the rapid development of wind power projects in the northwest. There are currently over 1600 MW of wind power in the NW and more on the horizon. This growth is being driven by the good economics of wind power and the emerging RPS measures.




Currently, wind project development is concentrated at the end of the gorge, with some build out in central Washington and east of Walla Walla. Interestingly, the best wind resources tend to lie on the continental divide to the east where there is very little development. There would be some advantages to distributing generation over the region more evenly.

The Northwest Wind Integration Action Plan (NWIAP) was lead by the policy steering committee, with the technical work group below it drafting the plan. Several groups fed into the technical committee.

The committee began by identifying the major questions facing the region:

- What is the role of wind energy in a power supply portfolio?
- Does the Northwest have the operational capability to integrate 6000 MW of wind?

- What are the transmission requirements for 6000 MW of wind?
- How will the costs of wind integration be recovered?
- How can the Northwest secure its wind potential in the most cost-effective manner?

Dave asked how the 6000 MW fits into the future of an RPS. Jeff said that the information they have comes form RNP, and they believe the 6000 MW would be more than adequate to meet Washington's RPS. When you add Oregon, and possibly Montana and some of California, this may need to be much higher.

The key findings from the first phase of the project (there will be a second phase that will continue into the next several years) were as follows:

- There are no fundamental technical barriers to integrating 6000 MW (based on current operational integration capability, which can be consumed by load growth and other restrictions from hydro).
- Preliminary estimates of integration cost range from $2/MWh (Low diversified penetration in large control area) to $16/MWh (High undiversified penetration in smaller control area).
- Control area cooperation and improved markets for ancillary and integration services will lower cost and increase availability.
- Existing transmission capacity can support anticipated wind development (~3000 - 3800 MW) through about the end of 2009. Beyond 2009 will require modification to the transmission systems. This is an opportunity for community wind which places less demand on the transmission system.
- Transmission expansion, firm/non-firm products and new regulatory policies needed to serve 6000 MW and to increase diversity.
- Wind's assured capacity value, the ability to reliably meet unscheduled peak demands, is probably lower than the provisional 15% assumed today.

Alan asked if the group will look at the need for and cost of redundant production to back up the low capacity value of wind. Jeff said that it is part of their work and the group is looking at the issues that comprise that question.

In terms of contributing to a renewable portfolio, wind power is a zero-emission energy resource with no fuel costs. Additionally, the primary benefits of wind energy are displacement of fossil fuel emissions and carbon dioxide production and reduced exposure to natural gas price uncertainty and volatility. The Pacific Northwest has many good, though scattered, wind resource areas. Wind power development in the Northwest has been largely concentrated in areas of compatible land use (open range and dryland wheat farming), favorable wind and access to available firm transmission capacity to the load centers west of the Cascades & California.

The requests for interconnection are all being concentrated in the same area at the end of the gorge. The transmission system is not capable of meeting all of these requests. There has been a blossoming of interest in the northeast where developers are connecting into the MATL interconnection system to send power north.

The capacity value of wind is dependant is affected by the peak load demands throughout the years. Extreme heating and cooling events frequently are driven by high-pressure weather systems and stagnant air. With increased penetration of air conditioning, summertime peaking demand is developing in the northwest, which cannot be met by our usually reliable hydro system.

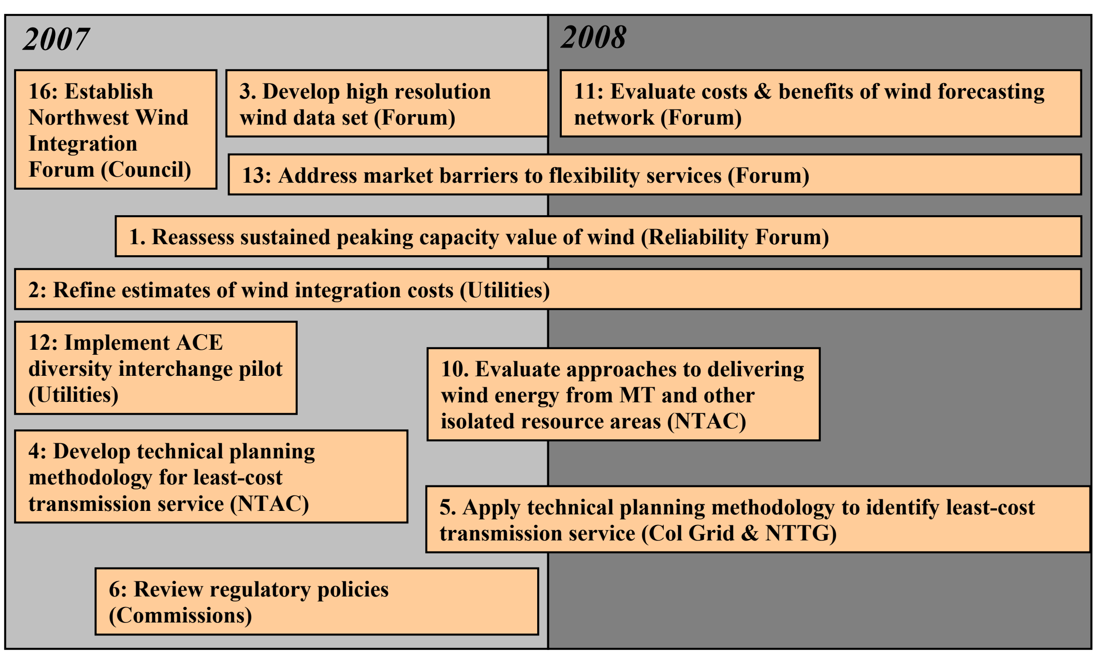
Wind energy increases net system variability and uncertainty, creating integration costs. Wind energy behaves like negative load, and managing wind energy is not fundamentally different from managing load variability. However, one megawatt of new wind is significantly more variable and less predictable than one megawatt of new load. Wind integration costs are driven by the costs of dedicating capacity to incremental operating reserves and to managing hour-to-hour changes in wind output.

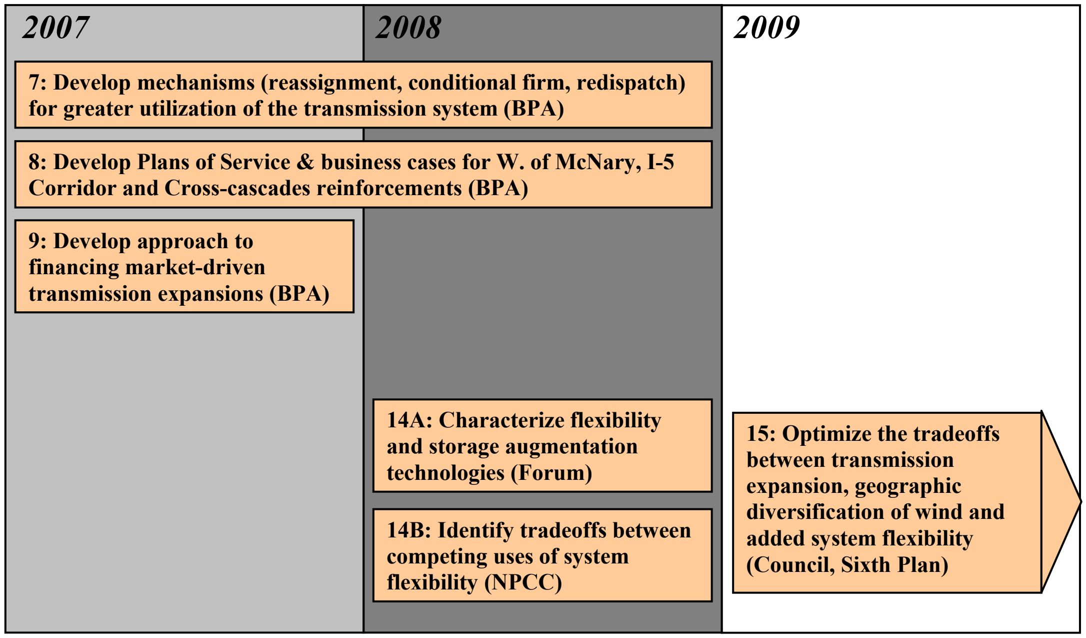
Dave asked what would happen to the operating reserve costs moving forward. Jeff said that is the $2-$16/MWh. The typical utility is in the lower end of that range. Five integration studies have been done in the northwest. BPA is in the process of doing a study, and has looked at within-hour impacts only. The people who have done these studies regard them as preliminary.

Creating a geographically diverse, low cost wind fleet will require access to wind sites with higher capacity factors and more diverse generation patterns will result in lower busbar and wind integration costs. Additional transmission capacity will be needed to achieve the economic and operational benefits of geographical diversification of wind projects. The current practice of providing full firm transmission capacity for wind power, with its limited firm capacity needs to be revisited. The transmission requirements for wind should not be centered on firm capacity, but rather energy. Needed transmission capacity can be provided by moving to partial firm transmission or by constructing new transmission.

The final result of these efforts was an Action Plan. Action item 16 establishes a Northwest Wind Integration Forum to oversee the implementation of the other 15 items. One of the first projects will be to develop a high resolution wind data set on a 2.5 km level for at least three sample years. This will give a better understanding of the benefits of geographic diversity. This should be available by the end of this year.

Develop technical planning methodology for least-cost transmission service (NTAC) is working on a technical planning methodology for expanding transmission capability. The Commissions have agreed to review their regulatory policies, and BPA is in the process of developing Plans of Service & business cases for W. of McNary, I-5 Corridor and Cross-cascades reinforcements.






The final report is posted on the webpage for the Wind Integration Forum (http://www.nwcouncil.org/energy/Wind/library/2007-1.pdf), available through the NW Power and Conservation Council website. A print version will be available soon.

John Reynolds said that the unreliability of wind occurs in the dead of winter and peak of summer. The standby hydro is often able to meet the winter peaks, but the peaks in summer might be met comfortably with solar. Jeff agreed.

## 4. Oregon Green Power Options

Lori Koho explained what is happening with green power programs in Oregon. The OPUC has a Portfolio Options Committee that ensures that there is a selection of green power purchase options for consumers. Peter commented that there are just over 1.4 billion kWh of green power being sold within the Pacific Northwest.

Lori said that the article published in the Oregonian in late January attacking the cost of marketing as a percentage of the premium for green power was an incredible hit to the purchase programs, and the Portfolio Options Committee has been investigating the concerns since its publication. The NREL report on green power purchase programs identified that the success of PGE's green power purchase program was directly related to the marketing effort.

Peter asked what issues the portfolio committee is considering and what changes are likely in the coming years. Dave, who also sits on the committee, responded that the most critical issue has been in response to the concern over the marketing for these programs. Contract renewal will be an issue in the future for both utilities.

Peter asked about the stability product at PGE. This is a stable-rate green power product that protects participating customers from most base rate increases over a five-year period. The Renewable Future product was developed as a pilot option for residential and small commercial customers based on market research that identified 5% to 7% of nonparticipating residential customers as interested in enrolling in a power option that offers green attributes as well as rate stability.

Thor replied that the program has been very popular and successful. The premium is about $14.38 for a residential customer, and about $17.00 per month for a small business. The plan for the future is to move it from green tags based to a fixed resource product. Dave commented that the stable price product has attracted new customers that aren't already involved in a green power purchase program.

**5. PMC Model Evaluation**

Phil Degens presented the findings of the recently completed contracting and delivery model evaluation. Energy Trust currently uses a variety of models to deliver and contract for energy efficiency and renewable energy programs. For some programs, the majority of work is outsourced; for others the majority of work is performed in-house, while other programs rely upon a combination of staff and contracted program functions, as in renewables. 2007 marked the fifth anniversary of Energy Trust, an appropriate time to revisit these models and see how they are serving the organization's needs as it grows and expands into new markets and sectors.

Research Into Action was selected as the contractor in response to a RFQ issued in November 2006 and interviews were performed in the first quarter of 2007. The goals of the evaluation were to assess the strengths and weaknesses of the various program contracting and delivery structures and to obtain recommendations to improve customer service and satisfaction, communications, and long-term cost-effectiveness. The results will be used to frame discussions and help identify the direction of program design changes. They will also be used to develop the next set of Program Management Contractor (PMC) request for proposals (RFPs).

The evaluation reviewed existing Energy Trust documents and evaluations, and interviewed staff, PMCs, Program Delivery Contractors (PDCs), trade allies, stakeholders and other similar organizations.

The evaluation found that Energy Trust uses a variety of models: PMC, mixed and internal. All of these models use third party contractors to some extent. Nothing is totally run in-house or completely outsourced. Program delivery contractors are usually selected using a competitive procurement process, such as a RFP or RFQ. The programs are meeting their goals and are perceived by almost all the parties involved to be working well to achieve these goals. The competitive procurement process is viewed as a key element to ensure cost-efficiency.

The interview with similar organizations revealed that the PMC model is most often used for residential programs. Others select delivery models according to market conditions, the degree of control they wish to have, and policy considerations (e.g. cap on FTE). It appeared that contracting out to third parties is needed, even with internally delivered programs.

Energy Trust compares favorably when considering program delivery costs across model types and when analyzing costs of electricity savings. Other organizations also used competitive procurement to keep costs down and felt that the approach they used was most efficient. Communication appears to be an issue with contractors in general, not just the PMC model.

The PMC process was viewed by most people as bringing outside expertise that could not necessarily be acquired internally. The competitive process keeps program delivery efficient. The PMCs view the Energy Trust-PMC relationship as more collaborative than in other contract relationships. The PMCs are very good at jump-starting programs, achieving savings goals and working with trade allies. Once the PMC is setup, it simplifies the Energy Trust contracting process.

The main issues with the PMC model were communications, coordination with other programs, the PMC focus on contract goals, aligning PMC and Energy Trust goals, complying with Energy Trust requests, cumbersome initial contracting process, engaging customers and developing long term relationships, and the potential for perceived conflict of interests (e.g. maximizing profit, growing their own business). Similar issues were identified by other the organizations that were interviewed.

In evaluation of the Energy Trust staff, individuals were very aware that being a lean organization is important to the way it is perceived. There was no staff consensus on the efficiency of specific delivery models. Internal program delivery was perceived to address some issues associated with aligning goals, communications, marketing, data management, and developing long term relationships with trade allies and customers.

Customers and trade allies revealed a moderately high level of satisfaction in most of the programs. Energy Trust is viewed as becoming more bureaucratic over time by some participants. The miscommunications about funds availability and project forecasts in 2005 and early 2006 are still coloring many stakeholders perceptions of the programs. There were some questions about the PMC commitment to fostering customer relationships.

The report concluded that stakeholders and staff feel that the anticipated changes in the Oregon energy efficiency market do not require a major change in the way Energy Trust delivers its programs. The main weakness of the PMC model is that it is applied the same way across all current programs and sectors. The major benefit of the existing model is that Energy Trust is perceived as administering public funds in an efficient and effective manner with minimal overhead. Competitive procurement is the key to the efficient program delivery, not a specific delivery model. Energy Trust would be more able to respond to market changes if it allowed the delivery model to be determined by market needs, not the perceptions of external stakeholders. Ultimately, any changes to the delivery models should be based on in-depth market analysis.

The evaluation contractor recommended four changes. Energy Trust needs to communicate that competitive procurement is the key to cost effective program delivery and not a particular model, and that the most effective delivery model is determined by market conditions, not a single approach to program delivery. Production Efficiency should be used as a case study of how to develop a different delivery model. Before rebidding any program, a detailed market assessment should be performed to determine if and how program delivery and design should change. Changes should be reflected in the new RFP.

The study implies that any change requires the continued dialogue with stakeholders (RAC, CAC, Board, etc.), which may take considerable time. Where there are opportunities for the PMCs to do more competitive procurement, they should. The next steps will be to collect detailed feedback from staff and committee, revise the report and discuss the final conclusions at the Board retreat in June.

Dave asked if there was any discussion of the optimum length of the PMC contract. Phil said there was some discussion, and most organizations lean toward a two or three year model. Longer models may not be viewed as competitive procurement on an ongoing basis.

**6. Not-for-profit Solar Incentive**

Kacia Brockman provided a brief summary of Energy Trust's efforts to develop a standard incentive to offer to tax-exempt parties looking to install solar. Currently, the majority of the financial incentives available to a commercial project come from the federal tax benefits, including the 30% investment tax credit and accelerated depreciation. The tax benefits may be leveraged by involving a third party investor with tax liability that owns and operates the solar electric system of the government or non-profit's building for some period of time. There may be a buyout option at some point that allows the tax-exempt party to take long term ownership of the system.

Staff believes there is significant market potential for this 3rd party ownership model. Governments and nonprofits are often motivated to install solar but lack the financial capital to make the investment. Solar is the most accessible renewable energy technology for public agencies and faith-based congregations with sustainability goals. Architects and engineers are looking at 3rd party ownership as a way to incorporate solar into new buildings, particularly those pursuing LEED certification, for public entities. Such installations could be an effective way to promote solar to those organizations' many constituents.

Energy Trust has met with 6 potential investors that are considering different investment models ranging from the flip model commonly used in wind projects, to an energy service company model where the 3rd party would retain long term ownership, to a lease-to-own model. For all the models, Energy Trust will need to pay an incentive higher than our standard commercial incentive in order to give the 3rd party investors a reasonable rate of return. This incentive would, however, be lower than would be necessary if we were not leveraging the federal tax incentives. It appears that the nonprofit incentive would be approximately $1/watt higher than the standard incentive (approximately $2.50/watt), but we are still analyzing the various models. Our goal is to create a standard incentive that can be applied to all the models for simplicity and predictability, and to shorten the time required for our application and approval process.

Although commercial businesses subject to the Alternative Minimum Tax are not able to claim the federal tax benefits either, there is pending federal legislation which may remedy that. For simplicity, staff proposes to limit this nonprofit incentive to tax-exempt entities.

There is a question of size. Currently, the standard incentive is capped at 50 kilowatts to ensure we spread the available incentives around. However, many of the investors would require a minimum size of 100 kW. Therefore, we are considering a size cap of 100-200 kW. Energy Trust expects to set aside a portion of the solar electric budget for both utilities for the nonprofit incentive to deal with this issue.

The net steps will be to continue to review investors' financial models and verify that government and nonprofit hosts will receive sufficient benefit from those models. Ultimately, the program will determine a standard incentive level that will work with a variety of models. Staff will need to review the implications of setting a nonprofit cap higher than the standard cap, and consider whether some larger projects should be allowed under the standard incentive, too. The appropriate budget amount to set aside for the nonprofit incentive will need to be determined, and possibly for larger standard projects. At this time, staff will decide if incentives will be provided on first come first served basis, or by a solicitation for projects. The application and approval process will need to be developed, including necessary terms and conditions for both the host and the 3rd party investor. Finally, Energy Trust will announce the new incentive and promote it.

Alan Meyer asked if the non-profit incentive is determined based on the greater above-market costs, why would a commercial business subject to alternative minimum tax (AMT) not be considered for additional incentives. Kacia responded that the offer is based on above-market costs, but not on a case-by-case basis. This is new market territory with potential to attract a new audience and increase participant diversity. Peter added that the third party investors have said that they are not interested in working with commercial businesses at this time. Alan said that if the cap is raised for the non-profit limit, it should be raised for the standard incentive as well.

Jon asked why the non-profit incentive funding should be kept separate from the standard funding pool. If the funds were mingled then it would be a first-come, first-served situation with a special effort toward tax exempt entities. Kacia said this could be considered. Peter clarified that there has always been caps within the budget for these projects to assure that more installers can participate more widely.

There were no other public comments. Peter adjourned the meeting at 12:00 pm.