Renewable Energy Advisory Council Meeting Notes

November 20, 2013

Attending from the council:
Robert Grott, Northwest Environmental Business Council
Juliet Johnson, Oregon Public Utility Commission
Suzanne Leta-Liou, Atkins
Michael O'Brien, Renewable Northwest Project
Vijay Satyal, Oregon Department of Energy
Frank Vignola, University of Oregon
Dick Wanderscheid, Bonneville Environmental Foundation
Tashiana Wangler, PacifiCorp
Attending from Energy Trust:
Chris Dearth
Pete Gibson
Fred Gordon
Jed Jorgensen
Betsy Kauffman
Thad Roth
Gayle Roughton
Peter West

Others attending:
Jerry Bryan, Farmers Irrigation District
John Charles, Cascade Policy Institute
Bruce Cordon, Clean Water Services
Bill Eddy, One Energy
Randy Neff, Clean Water Services
Ted Sorenson, Warm Springs Hydro LLC

1. Welcome and introductions

Betsy Kauffman called the meeting to order at 9:00 a.m. and reviewed the agenda. The minutes from the October meeting were approved. The agenda, notes and presented materials are available on Energy Trust's website at www.energytrust.org/About/public: meetings/REACouncil.aspx.

Betsy distributed the calendar for the 2014 Renewable Energy Advisory Council meetings.

Dave McClelland announced that the position vacated by Rob Del Mar has been filled by Jennifer Hall, with some changes in the role. Instead of Lizzie Rubado focusing on commercial solar and Jennifer focusing on residential solar, as Rob had done, Lizzie will now focus on customer experience and marketing while Jennifer will focus on the logistical and technical issues. Jennifer comes to Energy Trust from Synchro Solar and will join the team on December 10.

2. 2014 draft budget

Thad Roth outlined modifications from the 2014 draft budget that was presented at the October Renewable Energy Advisory Council meeting. Changes have been very minor from round one to round two of the draft budget. Thad first provided a general sector overview.

Thad: We encountered challenging market fundamentals this year but still have managed to maintain a robust pipeline for non-solar projects. Thirteen projects were reviewed and six projects have been selected for funding. Two were approved earlier in the year and four will be reviewed today. So we've had quite a bit of activity.

> We also started a new Project Development Assistance initiative through which we've awarded funds for projects representing four technologies. We spent less than budgeted but we have confidence we can build on this success. This is a new offering and we are learning about what the market is interested in, which will help us to improve next year.

We also approved and dedicated funding for a solar project from an Energy Trust Request for Proposals, RFP, for projects in PGE territory. We had thought those projects would come online this year, and now we expect them to come online next year.

At the last Renewable Energy Advisory Council meeting, we had some questions about what makes up the gap between the 2013 profit and loss, P&L, budget and the dollars we expect to spend by the end of 2013. In PGE territory, the difference comes from two sources: delayed or reallocated projects and funds remaining unallocated at the end of the year. For example, we had expected the solar project in PGE territory, from the RFP process, to come online this year. That was optimistic and that project was delayed, so that makes up about $1 million of the money not spent this year. The other source is that we were faced with the challenge of a really small pipeline, particularly on commercial solar, and we spent the year making adjustments on our incentives that resulted in a shortfall. Those funds will be moved forward to be used in the 2014 budget.

On the Pacific Power side, the gap is a bit bigger. Two major projects were delayed that make up about $1.8 million. Oregon Institute of Technology has a geothermal project that was pushed back to 2014 due to some permitting issues. Another biogas project was delayed as well. Generally, the shortfall is for projects that are still viable but coming online later. The unallocated funds will be rolled over into 2014. There may be some flexibility in the numbers as there are some projects where we are unsure if they will come online this year or next year.

Juliet: Only $0.9 million for PGE didn't go to a project and $0.19 million for Pacific Power didn't go to a project?
Thad: Correct. The others are just timing.

Vijay: Are those dollars added onto the 2014 budget?
Thad: Correct.

Juliet: I'm pleased to hear that Project Development Assistance is moving forward. This was a top priority item for the commission. What was the budget for this in 2013?
Thad: I believe it was around $1 million and I can get the exact number.
Juliet: So you are growing into being able to spend that amount?
Thad: Correct. We are still working on this and will be improving in the next year. There are projects out there ready to commit to a portion of the offer. What we believe will happen with these projects is that there will be an additional round of funding. It is probably more of a two-year cycle than a one-year cycle.
Juliet: I suggest you document what you are learning. Others could benefit from the knowledge you are gaining.
Thad: Yes. Betsy and her group will be working on that.

Thad covered the 2014-2015 renewable energy budget themes and budget numbers: We have $18 million in new dollars to allocate to projects this year that may complete in 2014 or future years. About 43 percent of the budget is going to Other Renewables and about 57 percent is going to Solar. That balance is based on our continuing efforts to maintain a viable standard Solar program and a solid pipeline. We are hopeful to outperform on our goals. Our total budget is very similar to 2013. I'll re-emphasize that we are spending more dollars on Solar than other projects to maintain that pipeline. We'll be in a pipeline-building mode rather than making big investments in 2014 for the Other Renewables program.

> The dynamics of the budgets are different for each utility. We spend only dollars received from PGE ratepayers on projects delivering power to PGE and the same for Pacific Power. It is more of a challenge for us to do projects using non-solar technologies in PGE territory, so 69 percent of the budget for PGE will go to support Solar with the remaining 31 percent supporting the Other Renewables program.
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> Pacific Power is just about opposite. This is where we can capture most of our non-solar opportunities. We are going to continue a competitive process for Other Renewables projects and focus on maintaining a viable standard Solar program. We are not in a position to do anything custom on the solar side this year.

Robert: The cost per average megawatt is the same for PGE and Pacific Power?
Dave McClelland: The cost for Pacific Power should be lower because of the lower incentives. There is more of a risk factor built in for PGE in terms of the conservative goal. We aren't sure that we will be able to allocate all those funds. We are seeing great growth in our pipeline since we've increased our incentives. We are hearing from our contractors that they are able to get a similar return to when there was a Business Energy Tax Credit. The costs have come down enough, by about 40 percent, that with no tax credit they think they can get the same return.

Suzanne: Does that mean you think that you are going to see an uptick in Solar projects?
Dave: We hope so. We think we are going to get more Solar activity, especially in PGE. Potential project owners have a feeling that they missed an opportunity now that the tax credit is gone, so we need to convince them that it's still a viable opportunity. We have a targeted marketing effort out there to commercial customers.

Vijay: There is a larger message than the loss of the Business Energy Tax Credit, that the industry is reaching maturity and can stand on its own.

Suzanne: We hear that the prices of solar components are increasing a little bit. Is that true?
Dave: We've seen prices stabilize. The market isn't being flooded in the same way with Chinese modules. The supply and demand is coming back into balance, so that has caused prices to stabilize. Our focus is on reducing soft costs. There is a quite a bit of difference between the soft costs of commercial and utility-scale projects, and we think we can help.

Suzanne: So prices of solar components are stabilizing but not up ticking. The takeaway is that costs might be stabilizing but that doesn't necessarily impact the general trend.
Dave: They are stabilizing and I think there is still room for much slower reduction in component costs, so our focus is about making the process more efficient.

Thad: The rest of our budget numbers are essentially the same. We will focus on biopower and hydropower, reflected in the projects you see later today. We'll be working on keeping our Solar program stable and streamlining our competitive process. We've had benefits and challenges that we want to learn from in the coming year.

Jason: Can you expand on how you are going to engage the OPUC's evaluation of the state's solar incentive programs?
Thad: We are going to have an opportunity to participate in a docket. There will be a report, and our role is to provide data and information that we have available and support that process. This is in response to HB 2893, which directs the OPUC to do a comparison of the Volumetric Incentive Rate, VIR, versus other funding opportunities, identify the benefits and challenges and produce a report. It needs to be completed by the end of July 2014 and we will support the process.

Thad: Any public comments on the draft 2014 annual budget are due November 27 and should be sent to info@energytrust.org. There is a public meeting at the OPUC on November 26, and then the final proposed budget will be taken to the board of directors on December 13. Any comments received will be summarized and provided to the board.

Juliet: Folks are welcome to come to the OPUC public meeting where Energy Trust will do a presentation on the budget and we will provide our comments.

3. Presentation of biopower project proposed for funding

Jed Jorgensen outlined the process for reviewing and approving projects before staff covered the details of this project. A lead staff member evaluates each project. An internal review memo is created and shared with a cross-department group. An independent, external contractor is also hired to evaluate the project. Projects are brought to the Renewable Energy Advisory Council before they are brought to the board. This is not required but the board has expressed interest in understanding the council's feedback and view.

Dick: Before you go, I'd like to say that I like that the Renewable Energy Advisory Council is now provided with the same staff reports as the board of directors and that you send them out before meetings. I commend staff for making these changes.
Jed: Thank you.

Dave Moldal presented on the proposed biopower project at Durham Advanced Wastewater Treatment Facility. Dave recognized Bruce Cordon of Clean Water Services for his work on this project.

This project includes a significant reconfiguration of the facility's digesters and construction of a brown grease receiving and processing facility, biogas storage and new gas cleaning equipment. The fuel for the reciprocating engines, otherwise known as co-generation engines because they produce power and heat, will be biogas produced by anaerobic digestion of municipal wastewater solids and co-digestible organic liquids. Clean Water Services intends to achieve commercial operation by January 2015.

Energy Trust proposes to offer a $3 million incentive paid in three installments. Energy Trust will request 65 percent of the Renewable Energy Certificates, RECs, for 25 years. The cost per average megawatt is $2.1 million. Brown grease tipping fees will produce about $330,000 in revenue a year. The only minor risk staff perceives is the facility not being able to secure enough co-digestible liquids for the engines to operate at full capacity. Given the facility's feedstock analysis, its location near a major transportation corridor, other sources of high strength organic wastes available in the region and increasing flows of wastewater solids into the treatment plant, staff is confident that adequate supplies of digestible materials will be available for sufficient biogas production to fuel both co-generation engines.

John Reynolds: Was the 2011 study on supply of available brown grease done for Washington County or a larger area?
Dave: The study was for Washington County only.

Juliet: Where does brown grease come from?
Dave: It generally comes from restaurants or food processing facilities. This material is collected in grease removal devices that are pumped out by waste haulers.

Jason: Are these the same fuels that are being turned into biofuels?

Dave: Those are typically yellow grease, which has higher energy content. That material is not normally put down the drain like brown grease but is separated.

Jason: So there is no present competition for this grease?
Dave: Not at this time, no.

Frank: What happens to the stuff they remove from the biogas?
Dave: The gas cleaning devices use iron sponge or carbon filters, which have to be replaced occasionally.

Jason: Is that why the project has 25 percent operations and management costs?
Dave: Yes.

Dick: Do those filters get put into a landfill?
Dave: That is correct.
Thad: There are some systems that can be regenerated, but you are removing a contaminant and it has to be put someplace.

Suzanne: What is the process to make the wastewater materials solid?
Dave: Wastewater materials are made solid more or less through a settling process. The municipal wastewater solids settle and then are pumped into a digester. In an oxygen-free environment, the solids are stirred and heated to a specific temperature. Bacteria in the tank digest the sugars, fats and proteins and produce biogas, which is approximately 60 percent methane. The biogas is also composed of carbon dioxide, nitrogen and contaminants such as hydrogen sulfide. Injecting brown grease and other co-digestible liquids into the municipal wastewater solids can greatly increase biogas production.

Juliet: Is a centrifuge used?
Randy Neff: There are two stages of separation. In the first stage, sludge primarily settles out. For the second stage, we use a centrifuge to thicken the materials.

Michael: Will the facility be net metering?
Dave: No. They will not be allowed to export power back onto the grid. They will use the power on-site, offsetting their retail rate.

Robert: Currently, the brown grease is going to landfills. Does this mean the competitive market for brown grease is the landfill?
Dave: Correct, plus other biopower projects.

Vijay: Is the 6 cents for tipping fees used in the analysis based on alternative costs of transporting brown grease for other uses?
Dave: Yes. This is also based on what we've seen on other biopower projects and tipping fees nationally.

Robert: With population growth in the district's service territory, you can use the full capacity of the co-generation engine. So if you keep the level of grease steady, will you increase the level of gas produced?
Dave: That is correct. We expect the facility will need an additional cogeneration engine in the future.

Vijay: So the supply of grease is affected by regulations rather than more sophisticated restaurants? Twenty five years seems to be a long stretch to predict. What are you relying on for this assumption on regulations?
Randy Neff: The state pumping code is new and is driving the regulation. Any time you have a new restaurant or significant remodel, they have to put brown grease removal devices in.

Dave: The digester is big enough to handle all the expected waste until about 2025. At some point in the future, they will likely add another digester and another engine.

Thad: Is it fair to say you have excess digester capacity?
Bruce Cordon: We do and we plan to add another digester in the future.
Randy: Yes, we have a plan to keep expanding our anaerobic digestion capacity as the population grows. As facilities expand, we will fully load our digesters. What the supply study showed was that there is plenty of supply.

Vijay: Be mindful of is what is driving the supply of brown grease.
Thad: We think regulations will increase, not decrease.

Suzanne: Is there any flexibility in your tipping fee value to account for an incentive to recognize the unknowns?
Thad: We've bracketed the analysis to account for a range and get a sense of the sensitivity.

Vijay: But you are still using a fixed tipping value throughout the life?
Thad: Yes, we think 6 cents is the middle ground. Clean Water Services will manage the risk of the availability of brown grease. They will need to maintain tipping fees to recover any lost revenue.

Robert: I saw you have gas storage in here. I'm not used to seeing this.
Dave: Yes, one of the digesters will be used as gas storage.
Thad: There is gas storage in a couple of the Revolution Energy Solutions projects, outside the digesters and under pressure.

Michael: What made you determine not to keep the facility below 2 megawatts so it could be net metered? Is this because most of the energy would be consumed on site, or because of the size of the two engines? Did you consider keeping the capacity below 2 MW so you could net meter?
Randy: Our determination was based on a comprehensive analysis of what we've produced over the years and projected into the future. In wastewater treatment, we have to use 20- and 50-year planning periods. We see our anaerobic digestion capacity as adequate. If you project gas production, it leads to a different engine size where we would be going if the project was just wastewater treatment alone. Now we have additional ability to take fats, oils and greases, FOG, so we can generate every bit of gas our digesters can allow. We were getting close to the net metering limit but that isn't what drove our decisions.

Robert: Who is the design engineer?
Randy: CH2M Hill.

Frank: What are you learning from this project to help other projects in Oregon?
Dave: We are learning a lot about operations and maintenance costs and how to reduce them. Every project varies and we are learning about reducing those significant costs so we can share that with others.

Randy: Clean Water Services prides itself on being a front-runner in clean energy technology. A week doesn't go by that we don't have a tour from around the country or the world. It is part of our corporate culture to educate others in the field.

Jason: Given operations and maintenance costs are on the high side, the benefits we are looking for are to advance carbon footprint and drive down operations and management costs. Is Energy Trust seeing a reduction in operations and maintenance costs?
Dave: On a cost per kilowatt basis, this project is almost the same as the City of Gresham's project. The costs are significant but not out of line. Thankfully, they are designing the facility to take advantage of additional biogas in the future.

Jason: I think it is important to look at these external issues because, bang-for-the-buck, this project seems low.
Thad: It is critical to understand that comparing projects is difficult. Incentives provided are based on energy projection. Medford changed an engine, they didn't have to build a building, so the cost of that project and how it's performing is very different. This makes it difficult to compare those two projects. JC-Biomethane is about the same size as the Durham Advanced Wastewater Treatment Facility, but JC-Biomethane had a $2 million incentive and benefited from other funding. The key issue is controlling operations and maintenance costs. Not as big a difference as we like to see. What can we do to improve that? In addition, right now you've got organic materials going to a landfill that may or may not have energy recovery and if it does, it's not nearly efficient as this. A benefit of this facility is capturing that waste and putting it to use. Plus we get the nutrients. These are not all direct energy related benefits, but they align with the goals of the state and are another key reason that we would provide the incentives.

4. Presentation of biopower project proposed for funding
Dave Moldal presented on the 395 kW Gresham wastewater treatment plant biogas project proposed for an incentive of $330,000.

> Energy Trust has been working with the City of Gresham for eight years, helping them achieve their goal of energy independence. With support from Energy Trust in 2005, Gresham replaced their first engine and installed a 395 kW Caterpillar engine fueled with biogas from wastewater solids. In 2012, Gresham installed a FOG receiving and processing station and began co-digesting available material. Gresham has secured more than 6,000 gallons per day of brown grease and other co-digestible materials through three-year renewable feedstock contracts with waste hauling firms.
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> The current project proposal includes installation of another 395 kW co-generation engine fueled with biogas, installation of a second storage tank for brown grease and food processing waste, replacement of an existing standby generator and associated modifications and improvements to the existing electrical and hot water systems and the digester building. Energy Trust is proposing an incentive of $330,000, to be paid in two installments.

Suzanne: Can you talk about what you are seeing as far as whether wastewater treatment plants are moving toward biomass nationally and in Oregon? A lot of these projects take a long time to get all the pieces in place. Is this particularly challenging in Oregon where we have lower energy prices or is this similar to what you see in other states?
Dave: The value of this project is that Gresham is offsetting their retail power rate and they can make the system work. We are not seeing an explosion in the number of these projects throughout the country, but the market is robust. There is a lot of biogas in Oregon being flared, and the market to take advantage of smaller volumes of biogas is improving as co-generation

technology using biogas is improves. Like the City of Gresham, it's really wastewater treatment plant specific on whether the technology will work and whether there is sufficient leadership and planning.

Betsy: Strategically, we see wastewater treatment projects as being a really important focus for us. There are a lot of factors coming together here. They are not selling into the wholesale market and they are taking advantage of tax credits. Wastewater treatment plants are big energy users. They have a big load, so they have a lot of motivation. In terms of the development and construction timeline, this project is typical of the projects we deal with. All renewable energy projects have a certain degree of complexity, so I don't see these projects as being exceptional. These municipalities have a lot of reason to do this because there are additional benefits.

Thad: I saw a national survey of wastewater treatment plants about a year ago. First of all, you have to use anaerobic digestion to create biogas to make a project viable. The survey looked at wastewater treatment plants that had anaerobic digestion and how many were using this for electricity generation and it was one in10. In Oregon, it's 10 out of 28. We're already performing at a high level. What we are seeing now are projects coming back to expand generation or repower. Those are opportunities for us to convert projects that aren't currently generating electricity. There are opportunities for new and expanding projects.

Robert: In the last project you used 25 years for analysis, but you used 20 years here. Why is there a difference?
Betsy: The typical project life is 20 years. In Durham, we made it 25 years because it matched the life of their financing.

Frank: It seems that these projects are running up against the net metering limit. At some point, in the future, they may need added capacity. Is this limit making it more expensive now and in the future? Have you looked into ways of sizing the systems and what would be the optimum size? How would you work with the utilities?
Dave: Gresham has confronted that today and they have designed their system to produce what is needed.

Thad: There are just a handful of these kinds of projects. I imagine we will see efforts by the customers to go to the utility and find a solution. From Clean Water Services (developer of the Durham project), I heard they sized the system based on what their needs were, not to be restricted by the net metering rules. How that plays out for other projects is yet to be determined. As we bump up on these limits, these customers will see what unanticipated issues are coming out. We'll understand that going forward. Net metering is a hot topic in the U.S. and that will have implications.

5. Presentation of hydropower project proposed for funding

Jed Jorgensen presented the 2.7 MW Warm Springs hydropower project proposed for an incentive of $740,000. On the phone was Ted Sorenson of Warm Springs Hydro LLC, the company developing this project. This project came out of the RFP that was held in August to solicit projects in Pacific Power territory.

Located near Burns in Eastern Oregon, this project would add a 2.7 MW turbine and generator at the base of the Warm Springs Dam. It would also run 2.2 miles of 25 kilovolt lines to interconnect with Harney Electric Co-op. The power would be wheeled across Harney Electric Co-op and Bonneville Power Administration to sell to Pacific Power. The dam is owned by Warm Springs Irrigation District and the Bureau of Reclamation. The facility is entirely used for

irrigation purposes. Energy Trust has not done a project on an existing dam before and there is a tremendous amount of potential for unpowered dams. This system is expected to generate on average 6,300 MWh annually.

Energy Trust has worked with Warm Springs Hydro before. The developer executed a past project on schedule, has a very skilled team and knows how to make these projects move forward. Financing will come from an existing relationship with Farm Credit Services. Farm Credit Services wants a personal guarantee based on other assets that the LLC partners own. If there is a low water year or series of years, it will tap into personal assets to cover the gap. Farm Credit Services successfully employed this strategy on other projects, which gives staff confidence that this arrangement will work well. The proposed incentive is $740,000 made in three payments. One payment would be made upon commercial operation, one at the end of the first irrigation season and another at the end of the second irrigation season if performance milestones are met. Energy Trust would receive 82,000 RECs, which is 65 percent of the expected generation. This is a REC value of $9.02 and an energy value of $1.03 million per aMW.

Dick: I recall a project that we approved with some experimental technology. How did you structure the incentive for that?
Jed: That was going to be paid on a cents-per-kWh basis.

Dick: So your concern with the other project was the technology and your concern here is the flow?
Jed: Yes. That's not really a concern, just awareness that some years will have less water than others.

Dick: How long did the other project take?
Jed: Three or four years. We are trying to cover two risks here: performance and additional risk developed by private entities versus municipalities.

Frank: With climate change, you can expect that things will be different in the future. The certainty that they will get 6,300 MWh in the future isn't very certain. In addition, you have to be careful with large volumes of water. What will happen with storms? Are they dumping greater amounts over shorter amounts of time? What has been done to protect the facility?
Jed: The climate change conversation is one that we've had about this project. To deal with that, we didn't look at the whole 40 years of past data. We looked at the last 10 and the 10 before that to determine an average that takes into account more recent climate conditions. In terms of storms, the dam is going to act as flood control barrier unless there is a massive overtopping.

Jason: Is sediment a consideration?
Jed: No, the outlets are at the bottom of the dam. Ted, can you explain how sediment is being managed?
Ted: Upstream of the dam is undeveloped land. It is primarily used for grazing. So the sediment load coming in is going to be rather low, and there is no sediment at the outlet at the base of the dam. They often drain the reservoir so we know what it looks like.

Jason: What is the response from the conservation community?
Jed: There is no controversy about the project.

Michael: The addition of hydro triggered the requirement that they needed to restock the fish. The dam itself is responsible but are all the costs put on this project?

Jed: The restocking is more of a recreational value to this reservoir and is not related to fish issues. It's about $3,000 a year so it is not a large concern.

6. Presentation of hydropower project proposed for funding

Jed presented the Farmers Irrigation District turbine upgrade hydropower project proposed for an incentive of $825,000. Jerry Bryan from the Farmers Irrigation District attended.

Energy Trust has done a fair amount of work with the district, helping it pipe much of the service territory. This last year was a drought year and the district had to shut down one of the plants about a month earlier than expected. It was able to meet all deliveries without rationing water and exceeded generation expectations by 400 percent even though it was a drought year. That was a big success.

This project will remove two existing 1 and 2 MW Francis turbines, generators and controls. They will be upgraded with a single 3 MW turbine. This is because the old turbines have not performed as well as expected and are causing a lot of extra operations and maintenance costs for the district. With this change, the district expects to increase generation by 12 percent without increasing capacity and save significantly in operations and maintenance costs. For replacement projects, total cost is considered but only additional generation is taken into account. Energy Trust is proposing an incentive of $825,000 to be paid in two payments. Energy Trust will receive 29,295 RECs which is 75 percent of expected generation. The REC value is $28.16 and the energy value is $3.7 million per aMW.

Dick: The power purchase agreement, PPA, will stay the same. Could Pacific Power have required a new PPA? It's my understanding they have a higher rate now?
Jerry: We tell them our limit and our probable maximum, and we use an average between those two. It is unlikely that the unit will exceed our max, but if it does, we simply explain we are now capable of producing more.

Robert: You're only giving them half the money they need, so where's the rest coming from?
Jed: They are borrowing the rest from the state. Essentially, they are willing to take a longer return.

Jason: On all the projects today, the program providing less that 100 percent of above-market costs. If you can go to 100 percent, why aren't you?
Thad: It varies. For Durham, when we modeled it with a higher tipping fee, we were paying 100 percent. We have to make assumptions for performance over a 20-year period and we tend to be conservative.

Robert: Do you negotiate incentives?
Thad: Negotiation is usually over the number of RECs rather than over incentives.

Michael: So this would be the first hydroelectric turbine replacement project that Energy Trust has funded? Was it just one of the first ones to come forward? Do you think there is a potential market for more?
Jed: Turbine upgrades are more common with larger hydro facilities, where a 3 percent efficiency increase translates into a lot of MWh. That is beyond our ability to support. If you just look at smaller projects here in Oregon, there is much smaller potential. Since we are limited to 20 MW, this is probably not something we are going to see a lot of but it is a place we can help out.

Robert: Why is this going to the Renewable Energy Advisory Council instead of the Conservation Advisory Council for efficiency?
Jed: It is still new, additional generation, not energy savings.

Frank: Is there any salvage value of the old turbine?
Jed: They estimate about a $100,000 value.

John: Did you mention in the previous project that one of the reasons the wheeling cost is low is because Harney Electric Co-op has an option on the project in the out years?
Jed: No, but it is in the write-up. Essentially Harney Electric is saying that it would potentially be interested in owning the system in the future and in exchange they are not charging a wheeling fee.

Thad: In our contracts we include provisions such that if a project doesn't generate or deliver to the intended utility for the full 20 years, there is a repayment schedule to protect ratepayer dollars.

7. Public comment
No public comment.

8. Meeting adjournment
Betsy thanked the council members for their participation and adjourned the meeting at 11:55 a.m. The next full council meeting is February 5, 2014.