MINUTES
ENERGY, ENVIRONMENT AND TECHNOLOGY
INTERIM COMMITTEE
WEDNESDAY, APRIL 19 AND THURSDAY, APRIL 20, 2006
JFAC MEETING ROOM
STATEHOUSE, BOISE, IDAHO

The meeting was called to order at 9:00 a.m. by Cochairman Senator Brent Hill. Other committee members present were Cochairman Representative George Eskridge, Senator Tom Gannon, Senator Curt McKenzie, Senator Elliot Werk, Senator Kate Kelly, Representative Maxine Bell, Representative Bert Stevenson, Representative Eric Anderson, Representative Ken Andrus, Representative Bob Nonini, and Representative Elaine Smith. Ad hoc members Representative Wendy Jaquet and Representative Mark Snodgrass were present for the April 19 meeting. Senator Patti Anne Lodge and Senator Gerry Sweet were absent and excused both days. Legislative Services staff members present were Mike Nugent, Paige Parker and Toni Hobbs.

Others present at the meeting were Ken Parker, K Energy; Don Dietrich, Idaho Commerce and Labor; Chris Hecht, Community Action Partnership Association of Idaho; Dan Pfeiffer, Ron Law, Paul Kjellander, Randy Lobb, Rick Sterling, Idaho Public Utilities Committee; LeRoy Jarolimek, Wind Advantage; Ken Miller, Northwest Energy Coalition; Dave Barnaby, Keep Magic Valley Magic; Michael Louis, Energy Policy Institute, Boise State University; Bob Hoppie, Idaho Energy Division; Brian Dickens, Idaho Office of Science and Technology; Robert Neilson, Idaho National Laboratory; Doug Glaspey, U.S. Geothermal, Inc.; Joe Williams, J.W. Tool Works; Representative Sharon Block, District 24; Courtney Washburn, Idaho Conservation League; Russell Westerberg, PacifiCorp; Gary Gould and William Edmo, Shoshone Bannock Tribe; Peter Richardson, ICIP; Jack G. Peterson, U.S. Department of the Interior; John Freemuth, Energy Policy Institute; Jess Byrne, Martin Bauer and Barry Burnell, Idaho Department of Environmental Quality; Russ Hendricks, Farm Bureau; Rich Hahn, Idaho Power; Neil Colwell, AVISTA; Rich Rayhill, Steve Voorhees, Stan Boyd and Dar Olberdig, Ridgeline Energy; Ester Gage, Snake River Alliance; David Hawk, J.R. Simplot Company; Ralph Williams, Idaho Consumer Owned Utilitites; Jeremy Maxand, Snake River Alliance; Kelci Karl, Idaho Association of Counties; Brenda Tominaga, Idaho Irrigation Pumpers Association; Lee Flinn, Conservation Voters of Idaho; Dave Tuthill, Idaho Department of Water Resources; Bob Cline, U.S. Geothermal; Dick Rush, Idaho Association of Commerce and Industry; Linda Lemmon, Idaho Aquaculture Association; and Mr. Jim Kempton, Dr. Terry Morlan and Mr. Jeff King, Northwest Power and Conservation Council.

After opening remarks from the cochairmen, **Mr. Robert Hoppie, Division Administrator of the Idaho Division of Energy,** was introduced to give an overview of the 1982 Idaho State Energy Plan. **Mr. Hoppie** explained that the Division of Energy merged with the Idaho Department of Water Resources in November 1981 because of the water **-** energy relationship. Executive Order 2001-06 maintains the division within the Idaho Department of Water Resources. Their duty is to provide technical information and financial assistance for energy efficiency and renewable energy resources.

Mr. Hoppie explained that the 1982 Energy Plan was created primarily to address supply issues covering all Idaho economic sectors and all available resources at the time. It primarily addressed electricity but did assess other energy sources and uses, primarily heating and transportation. In an overview done by the Energy Policy Resource Board it is noted that the plan "*...provides the people of Idaho with an outline of how the state can, through a series of policies and implementing legislation, assist the energy providers of the state in supplying adequate energy for the future."* In **Mr. Hoppie's** opinion, the 1982 plan provided what was intended: an outline of options, many of which are now in place.

The plan was developed as a way to deal with energy availability uncertainty and security. The Governor appointed the Energy Resources Policy Board and after 18 months the plan was completed. The plan's stated purpose is "*to assess Idaho's energy position and resources, to evaluate the potential demand versus supply capabilities and to set forth policies which can encourage development of adequate supply considering technical, social and economic factors.*" It states an objective to "*ensure the development of energy resources which will provide sufficient energy supplies for orderly and reasonable industrial and economic growth for Idaho.*" **Mr. Hoppie** said that these two aspects of the 1982 plan can still be guiding principles for this interim committee today.

Mr. Hoppie said that in many ways not a lot has changed since 1982. New issues that should be addressed in the new state energy plan include transmission and pipeline issues within and across the state, and energy facility siting procedures.

In his opinion the 1982 plan can be used by this committee as a starting point. He noted that the March 2006 Idaho's Energy Options assessment prepared by the INL would also be a good document to use.

Mr. Hoppie stated that if a new Integrated State Energy Plan is going to be a living, working plan, it should include plans for funding and regular review and updating. The committee should discuss early on how broad a focus the new State Energy Plan should have.

- Should it address all fuels for all uses?
- Should it focus on all energy sources and uses?
- Should it focus on electricity only?
- Should it focus on lighting, processing and heating only?
- Are transportation fuels to be covered?
- Which energy externalities (environmental quality, social impacts) would be addressed and to what extent?
- Should this plan address energy security or energy contingency planning?

Mr. Hoppie's presentation included a breakdown of the resources and resource issues covered in the 1982 Idaho Energy Plan. This is available at the Legislative Services Office.

Representative Bell commented that the 1982 plan was created through direction from the executive branch with the purpose to assess and evaluate energy demand and supply in the state. After that the plan seemed to sit on a shelf and collect dust. She asked if there has been any activity regarding continuation of such assessment or evaluation since the plan was established. **Mr. Hoppie** answered that the plan did not require any reports be made to the executive branch by the Energy Division or any other agency. He said that while there has been progress made in many areas included in the plan, it is not because of the plan but because of the way the state has changed over the years. **Representative Bell** said that as the state goes forth with another plan, any new plan needs to have reporting requirements and include provisions for review and updating on a regular basis.

Senator Werk asked if the 1982 plan resulted in any changes in the Governor's office in terms of contingency planning or if the Legislature responded in any way to provide added powers. **Mr. Hoppie** said he was not sure it was a direct result of the plan but in 1989, Idaho did create its only contingency plan for petroleum through the Idaho Division of Energy. This was done because funds became available from the Department of Energy. He said there is limited state funding available for this type of work.

Senator Gannon asked if the Division of Energy is located in the right department or if its location is why the state has not paid as much attention to the plan as it should have. **Mr. Hoppie** said this has been asked before and Idaho handles energy issues in the same manner as do 11 other states. Some states put it under their natural resources departments and some states have it in commerce or with their PUCs. Oregon has an actual department in statute. **Mr. Hoppie** said he does not think the location has hindered what has been done with the plan.

In response to a question from **Representative Jaquet** regarding the makeup of the Energy Policy Resource Board, **Mr. Hoppie** explained that the members of this board were appointed by Governor Evans and served for 18 months. This group had separate task forces on specific issues or resources and served as a group to develop the overall plan.

Representative Jaquet asked if the Division of Energy would work with counties to help them develop siting ordinances when an energy plant is proposed in an area. She also asked how his division would interact with a developer. **Mr. Hoppie** explained that his division does a resource assessment to make sure energy resources exist that would make it viable to open such a plant. He said they have only provided expert testimony for counties in zoning or city council type hearings.

In response to a question from **Senator Kelly** regarding contingency plans, **Mr. Hoppie** explained that the Bureau of Homeland Security in the Military Division of the Office of the Governor is in charge of having an emergency plan for Idaho. They address energy in this plan. **Mr. Hoppie** stated that his staff is involved in a contingency plan for petroleum. He added that utilities are required to submit their own contingency plans to the PUC. **Mr. Hoppie** said he would post these different state contingency plans on their website.

Representative Eskridge asked if there was any analysis that had been done on different sources of energy in terms of the economic and environmental pros and cons. **Mr. Hoppie** said they have performed economic analysis of wind and biofuel facilities that are fairly detailed. They also have data on conservation costs and benefits, but they have not looked at the environmental issues at any length. **Mr. Hoppie** said that the information that the committee received from INL at the last meeting would have the most up-to-date information regarding natural gas and coal prices and the long-term projections for cost.

Representative Eskridge asked for more information on the makeup of the Energy Policy Resource Board. **Mr. Hoppie** explained that all of the members served on a voluntary basis and it was staffed through the Idaho Division of Energy and the Governor's Office. He said that the current charge of this interim committee and the appropriation for a consultant could help make this a more substantial effort.

Mr. David Hawk, J. R. Simplot Company, explained that the initial assembly of the 1982 Task Force was due to the fact that oil and gas were not going to be available in the year 2000 and geothermal energy was going to play a significant role in our energy future. He said this group put together what they knew at the time. Changes have been dramatic since that time. Few of these committee members had a vision 10 to 15 years into the future that was close to accurate and almost no one estimated deregulation of natural gas and potential deregulation of electricity.

Representative Eskridge asked if the siting issue should be part of the energy plan or if it would be a logical step after development of the energy plan. **Mr. Hoppie** agreed that the actual plan might recommend that siting be established but, in his opinion, siting authority should not be part of the plan itself.

In response to another question from **Representative Eskridge, Mr. Hoppie** agreed that the plan needs to have annual reporting requirements and it needs to be decided what agency will be in charge of such a report. In his opinion, the plan must have a way to be updated if necessary and it should be reviewed in detail every few years. Oregon reviews their plan every two years.

Senator Hill asked, since the Idaho Energy Division does not rely on the 1982 plan, where does the direction come from. **Mr. Hoppie** said they rely on the agency vision and goal of providing technical information, and financial assistance for energy efficiency and renewable energy resources. Meeting this vision is tied to funding availability. He said that decisions are made by him with the approval of Director Dreher, Idaho Department of Water Resources and of the Governor.

Senator Hill asked whether more policy guidance would be helpful to them. **Mr. Hoppie** said yes. A primary example would be with wind (particularly related to PURPA) and whether the 90/110 band offered to PURPA contracts for wind power is in the state's best interest. A definitive policy in this area would be helpful either way. **Senator Hill** commented that the committee would appreciate any suggestions the Idaho Energy Division might have in this regard.

Mr. David Hawk, J.R. Simplot Co. was introduced to discuss the proposed energy plan. His complete powerpoint presentation is available at the Legislative Services Office. **Mr. Hawk** used the following as a mission statement for a new plan:

- **Develop state energy plan which addresses and advises local, state, regional and national issues of resource, consumption, price and stability of supply**

Components include:

- Energy use, efficiency and conservation
- Electricity
  - Traditional/Alternative Generation
  - Clean and Renewable
  - Utilities
    - Investor-owned
    - Municipalities - REA's and COOPs
    - BPA
    - Transmission
    - Renewable Portfolio
    - Western Governors Clean and Renewable Energy Advisory Committee
- Natural Gas
  - Utilities
    - Supply
      - Access
      - Cost
- Oil and Gasoline
  - Supply
      - Access
      - Cost

Mr. Hawk said that oil and gas could be addressed through resolutions and explained that Canada can drill in the Great Lakes and if a well has less than 5% oil cut, they are allowed to produce it there as natural gas that is piped onshore. The U. S. is not allowed to drill in the Great Lakes. He gave other examples of this.

Mr. Hawk's powerpoint presentation goes into more detail regarding each of these bullet points. This is available at the Legislative Services Office.

- Nuclear
- Hydrogen
- Idaho National Laboratory

- C Who builds resources - Who pays?
- C Role and Mission of State Agencies and the Governor's Office
- C Communication and Involvement
- C Energy Facility Siting

Representative Stevenson asked for more information regarding the investor-owned utilities and their integrated resource plans (IRPs). **Mr. Hawk** explained that each utility would be able to, at any time in their two-year process, give updates on the previous plan and where they are with the next plan. It is his understanding that anyone would be welcome as a guest to listen to what occurs as they develop the plans.

Senator Kelly asked if the Governor has an energy advisor and who it is. **Mr. Hawk** said he thinks of Jim Yost as that advisor. Mr. Yost sits in on Idaho Power's IRP development meetings.

Mr. Paul Kjellander, Public Utilities Commission (PUC) was the next speaker. He suggested that the IRPs, as they relate to current generation resources, could help the committee understand what is happening in Idaho with regard to the investor-owned utilities (IOUs). He said that even though the statewide energy plan from 1982 has not been used since it was developed, that does not mean that there has not been any planning or innovation going on in terms of generation resources in Idaho. Just the opposite is true. **Mr. Kjellander** explained that Idaho has an integrated resource planning (IRP) process that the utilities are actively engaged in. These are filed every two years. Almost as soon as a plan is filed, the process begins again for the next IRP. These plans are filed with the PUC. **Mr. Kjellander** commented that these plans are not accepted as a blueprint, they are accepted for filing. This is because things change very rapidly in the energy sector. **Mr. Kjellander** asked that during the next presentation the committee remember this is not a hard and fast blueprint, it is a forecast or a system of checks and balances.

Mr. Kjellander, introduced **Mr. Randy Lobb, PUC**, to give a brief overview of where the state is in regard to current generation resources and a discussion of the IRPs from the three Idaho investor-owned utilities the PUC regulates.

Mr. Lobb explained that he is the staff director at the PUC, and they process and review all of the filings that the three IOUs submit to the commission, including IRPs, certificates of convenience and necessity for new plants and general rate cases. The three utilities that submit IRPs to the PUC are Idaho Power, Avista Utilities and PacifiCorp.

Mr. Lobb said the PUC issued an order in 1989 that established the IRP planning process. One of the main reasons for this process was to incorporate demand-side management and renewables into the planning process of the companies. IRPs are not state specific, they are system specific. Avista serves Washington and Idaho, PacifiCorp serves six states and Idaho Power serves two states.

IRPs look at existing resources and determine what the load growth will be over the next ten to twenty years. IRPs look at both energy and capacity and identify possible resource alternatives including coal, wind, nuclear and even market purchases. They also compare costs and risks.

Mr. Lobb said that in his opinion, utilities view the IRP as their action plan. Utilities have integrated resource planning groups that incorporate a lot of different interests within the planning process.

Once the company completes their IRP, the plan is submitted to the PUC and it is reviewed and accepted for filing. The PUC does not approve or reject the plan. The staff reviews the plan to make sure it fits within a reasonable range. If the PUC sees something in the plan that is clearly unreasonable, they will make recommendations. Otherwise this is recognized as a snapshot in time that will change in two years.

Mr. Lobb explained that the companies are taking action on these IRPs. If their plan calls for acquisition of wind in 2006, a request for proposal is done and bids are taken and purchases are made from those bids. This is the same for whatever energy the plan proposes. The PUC expects that the utility's action plans will be in the form of request for proposals competitively bidding for each resource type. Once that bid is selected the utility comes to the PUC for a certificate of convenience in order to construct that project.

Mr. Lobb included a powerpoint presentation showing specifics of Idaho Power, Avista and PacifiCorp's integrated resource plans. This includes their service territories and supply resources. The IRPs include existing resources, load growth projections and what these utilities plan to acquire in order to meet that growing load. Links to these specific IRPs are available at the Legislative Services Office website: www.legislature.idaho.gov.

Mr. Lobb noted that the PUC uses the IRPs to back up what the companies request to construct and puts in rates. The PUC looks at the plan and makes sure the companies complied with the previous plan. If not, the company has to explain why it deviated from the plan. The PUC also looks at whether the company should have deviated from the plan; did conditions change sufficiently enough that the company should have reconsidered its resource acquisition strategy. The PUC expects these plans to be constantly evaluated.

Senator Gannon asked whether the CREP program plan to retire 100,000 acres of irrigated land out of production factors into Idaho Power's peak load projections. **Mr. Lobb** said he did not think that was factored into the old plan but it will be included in the 2006 plan.

Senator Gannon noted that last summer Idaho Power asked for a "time out" on PURPA projects and asked how many wind projects had been approved since that time. **Mr. Lobb** said he did not know but that a later speaker would answer that question.

In response to a question from **Senator Kelly, Mr. Lobb** defined renewables to include wind, solar, wood waste, geothermal and biomass. Hydro is not included in the definition of renewables.

Representative Eskridge asked how wind helps a utility meet peak demands. **Mr. Lobb** explained that wind is incorporated in the capacity calculation at whatever capacity the company believes the wind project will provide. The nameplate capacity may be 20 megawatts and usually only 30% to 35% of that is counted as capacity at any one time. **Mr. Lobb** stated that it is his understanding in the Idaho Power IRP that they will acquire 350 megawatts of wind nameplate capacity and 35% of that will be realized.

Representative Eskridge asked in terms of developing the IRPs, what consideration is given to actually be able to acquire or site the resources and whether there is any direction in terms of a siting preference within the state. **Mr. Lobb** answered that the PUC staff looks at the cost of the project and its impact on ratepayers. They want and expect the company to consider any environmental costs associated with a project or siting impact associated in terms of costs. The PUC does not actually evaluate siting or the air quality impacts. They do recognize that there are air quality issues and ask the companies how they plan to handle them. The bottom line for the PUC is to determine the least costly project when all factors are considered and the rates ratepayers will be charged to pay for them. **Representative Eskridge** said that there are really no policy implications except what the company thinks they want to do, given the input of their citizen groups when developing the IRPs. **Mr. Lobb** agreed.

Representative Eskridge asked whether the development of a state energy policy that provided a guideline in terms of resource diversity, renewables versus conventional generation, would reduce the risk to utilities as they followed their IRPs. **Mr. Lobb** answered that he was not sure that would make a difference. It would change the resource mix and the magnitude for request for proposals the companies would submit. In his opinion, the underlying siting issues and environmental issues would remain the same.

Representative Jaquet asked whether there was a way for merchant plants to be more involved in the request for proposal (RFP) process. **Mr. Lobb** said he did not know how merchant plants could become more involved. He said there are some wind development representatives in the planning process. It is **Mr. Lobb's** understanding that these merchant plants follow the IRP proposals of companies and look at time frames as to when a company might ask for proposals on certain types of energy in order for the merchant plant to have a proposal ready to go. **Representative Jaquet** asked whether, as communities grow and agricultural land is taken out of production, the power demands of the state would change. She asked whether the PUC or the power providers evaluate that. **Mr. Lobb** said the companies do that in the IRP process; they look at residential growth, irrigation and so on for each customer class.

Mr. Kjellander commented that Mr. Lobb's handout should be very helpful and a good resource for the committee to refer back to. **Mr. Kjellander** noted that two things need to be kept in mind: the utility has to be made whole for the investment it makes and the ratepayers ultimately must pay for that investment. That is what the PUC looks at as they look at a broader public interest. As a regulator the PUC looks at how to get projects integrated into utility resource stacks at a cost that is fair, just and reasonable. In other words, what is best for developers may not necessarily comport with what is in the best interest of the ratepayer. He noted that this was somewhat opposite of what **Mr. Hoppie** and the Idaho Energy Division do. **Senator McKenzie** asked whether Idaho has a special fund to help utilities pay for mandated percentages of renewables. In other states the ratepayers actually pay into this fund. **Mr. Kjellander** said Idaho has a tariff rider that attempts to provide a pool of money so the utility is made whole. He said there was a Supreme Court case that dealt with lost revenue that made the PUC realize this might not be making the utility completely whole.

Mr. Kjellander stated that in creating a state energy plan the committee needs to look more closely at the state building code because of conservation and the like. The issue here, according to **Mr. Kjellander,** is market transformation which he thinks is the most critical. In looking at conservation and demand-side management as it relates to residential customers, the PUC has found that when prices are high, people will look for ways to conserve but when prices begin to dip, some of those conservation-minded people stop conserving as much. He said that all three investor-owned utilities pay into an alliance that looks at the issue of market transformation. This organization looks at projects that they implement around the region as pilot programs. **Mr. Kjellander** said one way to ensure tremendous market transformation is to make sure that every new piece of construction meets a higher standard.

Mr. Kjellander commented that he would hope the committee would resist the temptation to create specific portfolio standards that have hard and firm capacity goals that are tied to specific timelines. The industry changes very quickly and the change is enormous. Setting firm goals could end up costing ratepayers down the road.

Senator Gannon said that the state of Idaho uses the International Building Code to dictate its energy standards. He asked if **Mr. Kjellander** is suggesting that Idaho should go beyond that and have stricter energy requirements. **Mr. Kjellander** encouraged the committee to take a serious look at doing that. Sometimes codes, just like rules, are not strict enough in order to get something out there that can be broadly accepted. Each part of the country has different needs and interests. **Senator Gannon** said it was his observation that conservation requirements in the International Building Code do consider regional needs in some way. He suggested that before the committee starts going beyond current code, they make sure the one in existence is being implemented throughout the state. **Mr.**

Hawk offered that at some point consideration should be given to looking at programs the investor-owned utilities have that give builders a chance to go beyond existing standards for conservation. **Mr. Kjellander** agreed and said that when appropriate incentive is in place, there is more cooperation and interest in complying with standards.

Representative Eskridge commented that other states have adopted portfolio standards for renewable energy regardless of cost. He asked how Idaho could develop a resource portfolio policy that would allow flexibility to recognize market changes and environmental considerations and to have guidelines in place without locking utilities into certain resources that would raise the costs to the ratepayers. **Mr. Kjellander** said that, as **Mr. Hawk** stated earlier, maybe the approach is to memorialize, in part, the IRP process that the utilities already have in place. They all have a piece in them for renewables that is based on the cost-effectiveness at the time the plan is established. Once that is completed, the utilities begin to look at it again. This tends to keep everyone on track with regard to where renewables fit in. Ten or fifteen years ago, many of these projects would never have been in an IRP because they did not meet the cost-effective test; now they are. **Representative Eskridge** asked if **Mr. Kjellander** believes that the IRPs are cost/price driven as opposed to environmentally driven. **Mr. Kjellander** commented that as **Mr. Lobb** had stated, when the PUC accepts the IRPs for filing, they are not going down the path for siting or looking at all of the environmental issues. One of the main reasons for this is that if the PUC did look at these issues, nothing would ever get filed. The process would go on and on. **Mr. Kjellander** said that fight is left for a specific project down the road. He noted that the companies do not completely ignore those issues, they are just not spelled out in detail. He speculated that in figuring out where Idaho Power plans to get its next 500 megawatts of coal, it will not be from Idaho. This is based, not on the moratorium legislation, but on what Idaho Power has seen with railroads. They do not believe they can rely on a railroad to deliver a coal resource to a coal fired generator they would own and operate within the state of Idaho. Instead they will be looking at something outside of Idaho. This brings transmission into the puzzle. **Mr. Kjellander** said the PUC has asked Idaho Power to look at transmission in their next IRP.

Mr. Kjellander said that the moratorium for coal fired generation could be perceived as a policy statement for the state of Idaho and this will lay out where the investor-owned utilities that have coal resources built into their IRPs will build these facilities. This will be outside of the state. He said this really points to how will we get transmission to those sites. Transmission right-of-way access costs on state land, in **Mr. Kjellander's** opinion, might be something this committee could look at. The other question is how will what the state wants to do with transmission dovetail with what is realistic through private land and in conjunction with federal corridors that might be laid out. **Representative Eskridge** commented that the committee, in looking at a state energy policy, could ask those same questions. He said they could look at generation resources within the state as opposed to those outside of the state. Looking at the economic advantages of employment, sales tax, income tax and so on to a site location within the state that involves one specific small area of land, as compared to lengthy transmission lines across many various parcels of public and private land. In his opinion it might be beneficial to look at an energy policy that addressed the issue of generation sites within the state. **Mr. Kjellander** commented that in his opinion, regardless of the moratorium, Idaho Power would not be looking within the state to locate a coal fired generator due to transportation issues. He mentioned the possibility of some type of incentive being offered to allow the utilities to work together to decide what is needed to best serve the entire region.

After lunch, **Mr. Kjellander** introduced **Mr. Rick Sterling, PUC Engineer,** to discuss the Public Utility Regulatory Policies Act of 1978 (PURPA). **Mr. Kjellander** commented that when he was first interviewed for his job with the PUC, PURPA was explained to him in a manner that said that utilities are told they must purchase certain amounts of energy whether they need to or not and that they must pay a specific price for it. At the time he thought that was wrong. As he got into the regulatory arena, his view of PURPA was that it was a mandatory obligation to purchase power generated by a qualified facility. Soon he discovered that PURPA is much broader than that. PURPA is a very broad policy act that was most recently modified as part of the Energy Policy Act of 2005 by Congress. The latest changes include issues related to standards for net metering, fuel source diversity, fossil fuel generation efficiency, time-based metering and some interconnection considerations. He suggested the committee look at a publication referred to as EPACT to see what the federal government is telling states they should be looking at over the next few years. The language in it is not a mandate but the issues this committee are looking at today will have to be dealt with by states. **Mr. Kjellander** said that Idaho has done a good job so far of looking at these issues and we are in compliance in those areas. Having reminded the committee that PURPA is very broad, **Mr. Sterling's** presentation will be dealing with the mandatory PURPA purchase obligation.

Mr. Kjellander explained that regarding PURPA, the states are taking a federal mandate and implementing it locally so each state is slightly different. He said that Idaho's PURPA rates are very good and we are one of the few states building PURPA projects today. One of the reasons for this is because the new federal PURPA regulations include language that allows for the termination of mandatory purchase obligations that investor-owned utilities have. **Mr. Kjellander** said that with that language, one could argue that Congress has said that mandating green power through PURPA might not be the best way to integrate it into an electric utilities portfolio. This rulemaking process has not been completed at this time, so today PURPA still applies.

Mr. Sterling, reiterated that PURPA is very broad but his presentation will deal only with the part of PURPA that requires utilities to purchase power that is offered for sale from small power producers. He stated that PURPA has been around since the nation's first energy crisis in the late 1970s. His complete power point presentation is available at the Legislative Services Office. **Mr. Sterling** explained the following terms:

- Qualifying facility - these are facilities that are eligible under PURPA to request that a utility purchase their power at rates that are established by the PUC in each state. There is really no limit on the size of projects for power like solar and wind. Hydro projects cannot be larger than 80 megawatts.
- Avoided Cost - is the incremental cost to an electric utility of electric energy or capacity, or both which, but for the purchase from the qualifying facility, such utility would generate itself or purchase from another source. In other words, avoided cost is the rate the utility would pay the small power producer if it was instead going to produce the power itself or acquire it from some other source.
- Avoided cost methodologies include:
  - Less Than 10 MW - Based on Gas-fired Combined Cycle Combustion Turbine
Same Rates for All Projects ("published rates")
Most Common Method

Mr. Sterling explained that for this above method, it is called a surrogate avoided resources methodology. This means they assume some surrogate type of plant that the utility would likely be building in the future. In this case since 1995, natural gas fired combined cycle combustion turbine has been used as that surrogate plant;

and

  - 10 MW and Greater - Based on Integrated Resource Plan Analysis
Project-specific Rates
Recognizes Individual Project Characteristics

Mr. Sterling's power point presentation shows more detail on how the rates are actually determined. He said there are generally four variables used for the calculations. They are either capital costs, fixed operation, maintenance and fuel costs. They make estimates of what those costs are and forecast them 20 years into the future because 20 years is the maximum life of a contract. The fuel variable is more than two-thirds of the cost component. **Mr. Sterling** said that seeing the volatility that has been experienced with natural gas prices, it becomes very difficult.

The rates are not changed during the 20-year period once a contract has been signed. The rate a project gets paid depends on how long the contract is and what year the project would go online.

Mr. Sterling said that, as **Mr. Kjellander** stated earlier, Idaho's rates are higher than the other surrounding states and this has been true for the entire history of PURPA.

Mr. Sterling's presentation includes charts showing the addition of PURPA contracts since 1981, the type of PURPA contracts and the megawatts produced by project type. He said that 90% of the projects with contracts are located in Idaho.

Senator Hill asked why the states pay different rates. **Mr. Sterling** explained that when PURPA was passed and FERC implemented the PURPA regulations said utilities shall pay avoided cost rates and left it up to each state to determine how and what those avoided cost rates would be. Every state has done it differently.

In response to a question from **Senator Gannon** regarding megawatts under contract, **Mr. Sterling** said it was nameplate megawatts.

Senator Gannon again asked how many wind projects have been approved since the PURPA moratorium has been implemented. **Mr. Sterling** reminded the committee that PURPA is not the only mechanism available. Utilities can acquire power in many ways including requests for proposals, nonfirm tariffs and net metering. All three investor-owned utilities in Idaho are at some stage, in some ongoing requests for proposals to acquire wind resources as shown below.

PacifiCorp
- 100 MW west side 2005
- 200 MW east side 2006
- 1,100 MW total renewables through RFP 2003-B
- 1,400 MW total over next 10 years
- Acquisitions so far include 64.5 MW Wolverine Cr. Project 10 mi. SE of Idaho Falls

Idaho Power
- Seeking up to 200 MW by end of 2007 (likely to reduce quantity due to PURPA contracts)

Avista
- Seeking 100 MW by end of 2007

Mr. Sterling explained that nonfirm tariffs are tariffed rates with no real contract. Power is sold if, when and as available and the rate paid is based on market price when the power is delivered. This has not proven to be a very popular option because project owners want to know how much they are going to get paid in advance.

Net metering is a mechanism that basically allows customers to run their meter backwards. If they produce more power than they use, that excess goes to the utility. When they use more than they produce, they purchase what they need from the utility. Net metering is discussed a lot but, according to **Mr. Sterling,** it is not that popular. Idaho Power only has 25 customers that are net metering with an accumulative capacity of slightly over 200 kilowatts.

Mr. Sterling stated that most of the new PURPA projects in Idaho that are signing contracts are wind projects. Wind generation has a lot of characteristics that make it much different than projects in the past so it has raised a lot of new issues that need to be dealt with. These issues include:

C Firm vs. Nonfirm energy (90/110% band)

Firm energy is energy that you know will be delivered and in what amount and when it will be delivered with a penalty for nondelivery. Nonfirm energy is delivered when it can be delivered. These two things are normally priced differently. In order for wind projects to receive certain rates, the PUC has determined that there needs to be some measure of firmness. This is where the 90/110% band concept came about.

C Integration Costs

It is more difficult for a utility to use wind when they do not know exactly how much is going to be there and when. They need to have plans in place in case the wind energy is not there.

C Planning issues - capacity factor, ELCC

On average, wind projects produce 25% to 35% of their rated capacity over the long term. It is also important to know when a wind project can produce its capacity.

C IPC-E-05-22 - Workshop process, Moratorium

There is a moratorium on signing new wind contracts unless the energy can somehow be firmed. There have been public workshops held to try to work through these issues without much success. The utilities are doing integration studies to determine what the cost of integration of wind will be that should be completed this summer.

Senator Gannon commented that the wind project people say this 90/110% band issue causes them a lot of problems. He asked, since the Fossil Beds project has been up and running for a few months, how the 90/110% band affects that. **Mr. Sterling** said he has not seen the generation figures. He last discussed this with Idaho Power about one or two months ago. That project went online around the first of the year and he has been told they have been able to meet their production of 90/110% every month but one, due to a problem with a turbine. **Senator Gannon** asked how many wind contracts have been signed since the moratorium went into effect. **Mr. Sterling** said that when the moratorium went into effect there were three or four projects in some stage of the contracting process and there had to be determinations made as to whether the moratorium applied to them. So far only one contract has been signed since the moratorium.

Senator Hill asked about the future of wind energy in Idaho as long as the moratorium is in place. **Mr. Sterling** said he does not believe the moratorium will be in place indefinitely and that many of the issues will be resolved in the next few months. Depending on the outcome, it is really a question of economics. Before the moratorium can be lifted determination of what type of requirements wind projects will need to meet in order to qualify for the "published rates," will have to be made. If these projects cannot qualify for the published rates, what rate they will get as an alternative will also need to be decided. **Senator Hill** said that each utility has plans to add wind energy to their portfolios in the foreseeable future. He asked how they will do this if there is not a rate sufficient to make the projects feasible. **Mr. Sterling** again stated that there are more options besides PURPA available for utilities to acquire wind projects. All three investor-owned utilities have RFP processes going on currently and these tend to be much larger projects than PURPA projects. He said that PURPA is a federal law that the state has to follow and the state does not have the ability to require utilities to pay more than the avoided costs. Those restrictions do not really exist outside of PURPA. There is no restriction in the law as far as what price would be paid for projects presented in requests for proposal. **Senator Hill** asked whether the investor-owned utilities are serious about acquiring these renewable resources and more specifically wind power even if it costs more. **Mr. Sterling** said he has the benefit of participating in all three investor-owned utilities integrated resource planning processes and due to the volatility of natural gas prices and the difficulty involved in building coal plants, in his opinion, all three utilities are very serious about wind generation.

In response to a question from **Representative Stevenson** regarding evaluation of wind projects to see if they are meeting the goals they say they can meet for firm power, **Mr. Sterling** said the PUC tries to do some evaluation but the PUC does not enforce the contract; that is up to the utility. He said the utilities watch that fairly closely. Even though some of the early hydro projects did not produce what they thought in terms of quantity, because they were hydro and many were associated with irrigation systems, it was very predicable as to what they would deliver and when. Wind is very different. Idaho has only one wind project of any size operating as a PURPA project so there is not a lot of data available.

Senator Gannon said he is familiar with how a utility in the Eastern part of the United States bills their power out using time-of-day metering and peak and off-peak rates. He asked if this is becoming more practical now. **Mr. Sterling**, as he understands it, said Idaho does have time-of-use rates for certain classes of customers including the industrial customers of Idaho Power. He noted that Idaho Power also has a pilot project for time-of-use rates in certain parts of its territory for its residential customers. There are some requirements in the recently passed federal energy bill for time-of-day metering. **Mr. Sterling** said it is coming although he is not sure all residential customers will have it.

Representative Eskridge asked regarding avoided cost, why gas fired combined cycle combustion turbines were used and given today's fuel cost if it is still the best rate to use. **Mr. Sterling** explained that in early PURPA the coal fired power plant was used to figure avoided cost rates because that was what utilities were building in the 1980s. In the 1990s that changed to natural gas fired plants and they are still the most recent resources being built. He said from here forward that may not necessarily be the resource that is avoided.

Representative Eskridge noted that Idaho Power is going to reduce its plan for 200 megawatts of wind through requests for proposal due to the number of PURPA contracts it has. He asked if those PURPA contracts are more expensive than requests for proposal contracts would be. **Mr. Sterling** said the evaluation of proposals the utilities are involved in have confidential prices. In his opinion, today those rates are probably in the same ballpark as PURPA projects. **Representative Eskridge** commented that his concern is for the ratepayers, so as long as the rates are comparable, that would be ok. His concern with PURPA is that we could be asking the ratepayers to pay more than they should. **Mr. Sterling** said it is difficult to answer that question because they are trying to establish rates for 20-year contracts today into the future, and it will not be known for 20 years whether we paid too much or too little.

Representative Anderson said that many countries are into the process of using time-of-day metering and it would seem to him that the PUC could take an active role in time-of-day metering. In his opinion this would seem to be a conservation measure that would help keep the reservoirs full. **Mr. Kjellander** stated that time-of-day metering does exist in some of PacifiCorp's territory and there are pilot projects with Idaho Power involving smart meters. As part of the 2005 "EPACT," Congress is saying that the state has to look at and address this issue. The Idaho PUC feels pretty good that we have already taken those steps to get the process moving. Avista also has some pilot projects. He said that one of the reasons Idaho is not as far along as some other states is due to the fact that we have historically had some of the lowest rates in the nation. Time-of-use rates make sense when rates are higher. customer reaction to this also has to be considered.

In response to a question from **Representative Anderson** regarding whether line losses had been taken into consideration in the PUC's economic forecast, **Mr. Kjellander** said if he had his preference he would rather see some type of distributing base load generation closer to a load center rather than having to deal with line loss and what that actually costs ratepayers down the road. On the other hand, if generation cannot be built next to load, there is really no other option.

Representative Eskridge asked whether information was available regarding the price for a long-term 20-year contract for coal generation. **Mr. Kjellander** said that was typically proprietary information. He said the only talk he has heard of 20-year contracts is from large scale merchant generators who are trying to drum up support. They need to cross the 75% threshold of having contracted energy to actually break ground on a project. He has not seen any of those contracts come through the PUC. He added that he is not aware that any of the investor-owned utilities have the desire to sign a 20-year contract which may suggest there is another resource they could acquire for less. **Representative Eskridge** stated that he asked this question because he is still concerned about PURPA and how the avoided cost is set. His concern is with what the ratepayers ultimately pay for the energy that is produced and the regulatory environment that impacts those rates. He said he is wondering if our PURPA comparison for avoided cost is still valid and gives the best benefit to the ratepayer. **Mr. Kjellander** commented that he had heard that some people think that wind under PURPA contracts were a way for Idaho to avoid the high cost and volatility of natural gas. He said once it was explained that the avoided cost rate used includes fuel cost for natural gas, it was understood why PURPA contracts for wind might not help avoid the volatility of natural gas. He added that the avoided cost rate does not change every year even though the price of natural gas may have changed.

Mr. Peter Richardson, attorney for the Industrial Customers of Idaho Power, responded to the questions relating to time-of-use metering. He said time-of-use metering was imposed on the industrial class by the PUC in the last general rate case over their objections because time of use metering is not effective in changing the behavior of the industrial class. He stated that one of the reasons this was imposed on them was because they have metering that is capable of measuring time-of-use, whereas the residential class (where time of metering would be useful) does not have those types of meters. **Senator Gannon** said the customer he is familiar with that has time-of-use metering was set up for about 1/3 of the total day. They paid more during peak hours and less during off-peak hours. He asked whether the rates went up or did they break even for the 24/7 time period. **Mr. Richardson** said that for the class as a whole, it pretty much broke even. In his case as a potato processor, keeping a cold room cold in the middle of the day in July, he paid a lot more.

Mr. Richardson noted that he represented the Fossil Gulch Wind Project developer and that they would like to speak to the committee at another meeting regarding another side of the PURPA avoided cost story and the moratorium.

Mr. Lobb was reintroduced to give a presentation on how utility rates are set and the role of the PUC. This complete power point is available at the Legislative Services Office. He explained that the PUC's role in ratemaking is to prevent excess profits, assure adequate earnings, assure safe and reliable services and establish reasonable rates. He said this is a balancing act when they evaluate a rate filing made by a company. The PUC has had six large general rate filings in the last three years.

The basis for traditional ratemaking is that the company has an obligation to serve. They have to serve all comers. Companies have franchised service territories and they are provided with an opportunity to prudently recover cost of service through rates.

The traditional ratemaking formula looks like this:

Revenue Requirement - the amount of revenue that must be generated from sales in a single normal year

equals

Capital Recovery - the recovery of investment through annual depreciation expense over the life of the asset
plus
Return on Investment - provides a weighted return based on debt interest and a reasonable return on equity (this is the only profit a company makes)
plus
Normal Operating Expenses - normal, annual, recurring operation and maintenance expenses such as labor, fuel and insurance

Mr. Lobb added that the term "rate base" is the undepreciated investment that the company has on the books. They can earn a return on this also.

Senator Gannon asked if companies are allowed to capitalize major maintenance function events and depreciate them off. **Mr. Lobb** said it depends on the type of maintenance. Fixed operation and maintenance are annual expenses. A major rewind on a generator at a hydro power plant that is a major capital investment is capitalized. Large pieces of investment that extend the life of a plant are capitalized.

Mr. Lobb went on to discuss how the PUC establishes revenue requirement. He said when a company comes in, it is up to them to choose what is used as a test year. The PUC uses this historic test year's actual costs incurred to perform and operate the business and normalize it. The PUC makes adjustments for known and measurable changes. Next, the PUC establishes a rate base for that test year and establishes a return on that rate base. This return is based on their capital structure. The return on the rate base is what the PUC believes the company needs to pay an investor to attract their capital or buy stock. The final step is to gross up for income taxes. He explained that the revenue requirement is after tax.

The revenue requirement formula is as follows:

Annual Revenue Requirement =
One year of Depreciation Expense +
Annual Return on Investment +
Annual Operating Expense +
Annual Income Taxes

The energy rate formula:

Normalized Annual Revenue Requirement
($)
divided by
Normalized Annual Energy Used
(kWh)

Mr. Lobb said this formula is straightforward in theory but very difficult to apply. In theory this would result in a kilowatt hour rate and everyone would be charged the same kilowatt hour rate and that would recover the cost the company needs. This would be one rate structure.

Another rate structure looks at cost of service where the revenue requirement is parceled out to each customer class based on cost of service. It might cost more to serve a small commercial customer based on load characteristics than it does to service an irrigation customer or large industrial customer that uses energy at the same rate all year long. After revenue requirement is assigned to each customer class then rate design is done. Rate design includes three components:

C Customer Charge, $/month ($4.00 per month proposed at the last rate case)
This is designed to recover things like metering. The staff has proposed that the customer charge be no more than the revenue requirement associated with the meters used for billing and collection. The company has to have a meter whether the customer uses any energy or not.

C Demand Charge, $/kW
This is the cost involved with the fact that power is available any time the customer wants it. Residential customers do not have a demand charge. Large industrial and irrigation customers have demand charges because they have large demand that puts greater demand on the company to instantaneously provide power. This is measured and billed.

C Energy Charge $/kWh
This is the rate per kilowatt hour (the more you use, the more you pay)

Senator Kelly asked if the investor-owned utilities are corporations in business for profit. **Mr. Lobb** said that was correct. **Senator Kelly** asked how the fact that the PUC makes sure these companies do not make excess profit fits with the fact that the company is trying to make profit. **Mr. Lobb** explained this is where setting the return on equity comes into play. That is the only place the company can make profit. The PUC calculates how much money a utility company needs to earn. The companies are given enough money to cover operating expenses and depreciation. They are also given enough money to cover their interest payments on debt. The return on equity is authorized by the PUC and if they exceed that, the company can be called in and can have their revenue requirement lowered. Companies continuously monitor this also. **Senator Hill** explained that because this is a regulated monopoly, the PUC is setting the rate of return on investment so if someone buys stock in Idaho Power, they have a good idea of what kind of return they will get because there is a cap.

Senator Hill asked what incentive is built into this formula for cost-efficiency within a company and who pays if a mistake is made within a company. **Mr. Lobb** said this is really what the PUC is for. The staff does audits and looks at the prudency of costs and compares it to other utilities as well as to a history of the company. They look for trends and will raise issues if costs seem too high. **Mr. Lobb** noted that the shareholders would be responsible for costs the commission deems to be too high or inappropriate. There have been several cases of this in the past.

Representative Eskridge asked if there is a built-in incentive for companies to invest in their own facilities as opposed to a power purchase contract. In his opinion, an investment in your own facility would carry a guaranteed rate of return and a power purchase contract would only be an expense, it would not provide a return. **Mr. Lobb** said the PUC looks at this all of the time. He said you would think there would be incentive to build plants and add rate base in order to earn more profit. But rates also go up or people might use less of your product. Also a company might be less competitive if deregulated. This, in his opinion, adds others pressures to keep costs down.

Mr. Lobb went on to discuss the power cost adjustment (PCA) mechanism. A power cost adjustment is an annual mechanism that adjusts rates based on the variable cost of power supply. These are the normalized costs he discussed above and include fuel, purchase power and surplus sales revenue. He said that surplus sales revenue is a very important part of the PCA. In good water conditions this is where companies make their money and that revenue is shared with ratepayers. He explained that Idaho Power and Avista both have a power cost adjustment (PCA) mechanism. This is an annual tracker that recovers power supply costs annually. Water conditions affect power supply costs and generation in hydro power plants and the generation in hydro power plants affects power supply costs. In poor water years the company requests a surcharge and in good water years, prior to the PCA, they kept the money. PCAs were put in place originally to provide some symmetry, so that in good water years, the company would share the profits with ratepayers.

Mr. Lobb explained that PCAs have four parts:

- **Projection** converts runoff forecast into power supply cost estimate
- **True-up** the difference between previous year projected power supply cost and actual cost
- **Adjustment** for actual PURPA costs that exceed $55 million and average power supply cost of serving new load
- **PCA costs above or below normal** are allocated 90% to customers by changing the cents/kWh energy rate

Mr. Lobb's presentation includes charts showing Idaho Power's 2005 PCA projection and the history of PCA amounts.

Representative Stevenson asked when these PCA are done. **Mr. Lobb** said June 1.

The final portion of **Mr. Lobb's** presentation involved natural gas. He said that the PUC primarily regulated Avista and Intermountain Gas Company in Idaho. They each file purchase gas adjustments (PGAs). These are very similar to PCAs. His presentation also includes charts showing Intermountain Gas Company's residential prices and Avista's residential rate per therm in Idaho and what is included in the gas rates. The price of gas is by far the largest piece of both companies' rates today. Neither company owns any gas wells, they buy from the market. **Senator Gannon** asked if there is a huge storage area in the west where large amounts of natural gas can be stored similar to the one in Chicago. **Mr. Lobb** said that each company has a generic storage area. Avista has about 10% of their winter usage in storage. He said Intermountain Gas has significantly more storage; about 40% and that is one reason their weighted average cost of gas is lower than Avista. Both companies are trying to acquire more storage.

Mr. Lobb's final slide shows the forecast for Northwest gas prices from March 2006, through September 2009. The forecast ranges from $6.00 up to almost $11.00 and back down.

Mr. Ralph Williams, General Manager of United Electric Cooperative representing the consumer-owned power companies in the state of Idaho including municipalities and rural electric cooperatives was introduced to discuss the future energy needs of these types of power companies**.** He distributed a handout titled "Idaho Consumer Owned Utilities; Future Energy Needs" that is available at the Legislative Services Office.

Mr. Williams explained that the Bonneville Power Administration (BPA) is the supplier for virtually all of the power requirements of the consumer-owned utilities in the state. Small generation projects are owned by consumer-owned utilities but do not make a significant difference in the overall picture.

Mr. Williams said that Bonneville customers have contracts for power that will cover consumer-owned power needs until October 1, 2011. Presently Bonneville and its customers are working collaboratively on a proposal for future power supply contracts for the 20-year period post 2011. This process is called Allocation of the Federal Base System (FBS).

Allocation means basically dividing up the FBS and defining for each BPA customer what percentage share of the FBS output they can count on for the future. For consumer-owned utilities for loads not covered by the allocated amount purchased from BPA, each utility will be responsible for acquiring power to meet load growth in its service area. This is a whole new world for consumer-owned power who has basically had BPA to supply "full requirement contracts." **Mr. Williams** said that these utilities may choose to aggregate loads and work together to purchase power. These utilities may very well hire BPA to be their aggregator.

Mr. Williams discussed a slide showing a BPA graph of actual and projected load growth into the future. This graph shows that after 2011 each consumer-owned utility in Idaho will be in deficit and will have to go out and purchase power from other generation resources. This graph shows that the consumer-owned utilities between now and 2015 will need about 75 megawatts more of power. These projections are based on historic usage where in the rural area there has not been a lot of growth. Historic growth for consumer-owned systems has been 1% to 2% annually. **Mr. Williams** emphasized to the committee that this is changing in rural Idaho and in the municipalities that are served by BPA. In his opinion, new updated projections need to be made so better decisions can be made going forward. Significant loads locating in the small utility's service areas have profound effects. He said that consumer-owned utilities are going to be in the market needing generation resources in the 2012 time frame.

Mr. Williams noted that another equally important component to electrical supply is the ability to transmit additional resources into the state. He said he is hopeful that the committee will discuss that at a later date.

Mr. Williams distributed a paper authored by Mr. Donald Dean who has served on the Mini-Cassia regional economic development council for many years. This paper discusses the increased growth that is beginning in that area and how that will affect the region's power needs in the near future. One example he used is that a large cheese producer who was considering locating there would have used 12aMW of energy compared to the entire city of Burley, that uses only 16aMW.

Mr. Williams went on to say that some consumer-owned utilities have already taken action. The cities of Burley, Rupert, Heyburn, Idaho Falls and United Electric Coop are participating in the Intermountain Power Project in Mona, Utah. Even with 2% load growth, these utilities will be in need of more energy soon after 2012.

His presentation also included a table showing actual megawatt usage for the different consumer-owned utilities for 2005 and forecasting needs for 2015 and 2025.

The bottom line of his presentation is that the rest of the world has discovered Idaho and electrical load growth is inevitable. Long-term stable power contracts are and will continue to be at a premium.

Senator Kelly asked how the consumer-owned utilities are regulated compared to the investor-owned. **Mr. Williams** answered that electric cooperatives have an elected board who make sure service is delivered and keep rates in line and competitive; those elected directors hear from the members. For municipalities, the regulators are the city councils. In response to another question from **Senator Kelly, Mr. Williams** said there are pockets within Idaho Power and Avista service territory that are served by municipalities and consumer-owned. If these are located within an investor-owned utilities service territory, that investor-owned utility cannot service that customer. The coops and municipalities have defined service territories and they do not overlap. He said they also have service territorial contracts between each other that are filed with the PUC that do not overlap. **Senator Kelly** asked if the PUC has any authority over the consumer-owned utilities. **Mr. Williams** said they do not.

Representative Bell asked what do the consumer-owned utilities do to plan for the future energy needs. **Mr. Williams** answered that each utility does load forecasts and collectively they belong to associations and organizations that also look to future energy needs and load forecasts. BPA is the primary power supplier and they look into the future energy needs for the consumer-owned utilities also. **Representative Bell** asked if these consumer-owned utilities are victims of the marketplace and supply and demand as growth occurs. **Mr. Williams** said not yet, but if the allocation proposal happens, they will be, even though that may be the correct thing to do.

He noted that once they have to secure their own power, they will be operating in the same arena as every other power company in the U.S. has already had to operate in. They will need to go out and find power supply that is stable and long-term. They will need to find transmission paths to get the power to the systems.

Representative Eskridge asked when the consumer-owned utilities start looking into the future beyond BPA if they are looking to secure their power through power purchase contracts or participation in facilities. **Mr. Williams** said they are starting to work toward IRPs but they need to work collectively with others due to the small amount of megawatts they need. He said he would like to see the Legislature come up with a plan that would give direction as to what can and cannot be done in Idaho. If they cannot build generation in the state, they have to work to build transmission into the state to get the power here.

Representative Jaquet asked if consumer-owned utilities could be acquired by Idaho Power or PacifiCorp or Avista as an option. **Mr. Williams** said yes. **Representative Jaquet** said she would like to have **Mr. Williams** speak at another meeting to give the committee information with regard to where they are and how things are changing. **Representative Stevenson** commented that a few months ago United Electric Cooperative acquired part of Idaho Power's service territory because it was easier for them to service than Idaho Power.

Representative Eskridge stated that he would also like more information from **Mr. Williams** on how they see the potential energy policy development affecting their operation as the process moves forward.

Mr. David Hawk made the following comments in response to some of the issues **Mr. Lobb** discussed earlier.

1. In choosing a utility-owned plant versus a merchant ownership, from the industrial side of things, they believe that the economically required return on equity for the utility may be less than that required for a merchant generator to build a plant as long as the utility can operate and build it at the same cost. This would make the cost of power lower.

2. Rates and choice of generating ownership are determined in a ratemaking process where, not only does the staff cross-examine and scrutinize, interveners do this as well, providing significant checks and balances.

3. The utility is not guaranteed that they will earn their allowed rate of return. They are given an allowed rate of return, but that is not guaranteed; they are only given the opportunity. The only thing to be concerned about is, in getting to the point of earning their rate of return, the utility does not forsake maintenance and operations that are necessary.

Mr. Martin Bauer, Administrator of the Air Quality Division - Department of Environmental Quality, was the next speaker. His presentation deals with air quality standards that relate to power generation. His complete powerpoint presentation is available at the Legislative Services Office. **Mr. Bauer** stated that his presentation will walk the committee through what a large emission source, similar to a power generation unit, would have to go through today, what is coming up on the horizon and what to keep in mind moving forward.

Mr. Bauer noted that combustion sources such as coal, natural gas, diesel and wood are what will require air quality scrutiny. These are referred to as large sources and will be required to get prevention of significant deterioration permits (PSD).

Air quality permitting requirements for power generation facilities today include:
C	Must show compliance with National Ambient Air Quality Standard (NAAQS)
C	Meet all emissions standards including Toxic Air Pollutants (TAPs)

- Must demonstrate Best Available Control Technology (BACT)
- Must analyze impairment to visibility, soils, and vegetation
- Must provide an analysis of secondary emissions associated with the new facilities (i.e. commercial, residential, and industrial growth)
- Must meet all public participation requirements which can include comment and hearing

In response to a question from **Representative Anderson, Mr. Bauer** explained that this is only required when a source comes in that is going to emit, say, 250 tons of pollutants. Then they have to look at associated secondary emissions. If a source is not required to get a permit to begin with, they do not have to look at their secondary emissions.

Representative Nonini asked what associated secondary emissions would be. **Mr. Bauer** explained that they are those emissions that are accompanied by the source moving in. This is not just stack emissions and could include the fact that the employees will be burning wood to heat their homes and will be driving more cars.

Issues to consider in the future, according to **Mr. Bauer** are:

- Clean Air Mercury Rules (CAMR)
- $PM_{2.5}$ destinations and potential nonattainment areas
- Regional Haze
- Greenhouse Gases

The clean air mercury rules:

- A national rule to control mercury emissions from coal fired electric utilities only.
- Mercury is an air toxin which is transported and deposited in lakes and rivers and accumulates in aquatic organisms. Most exposure to mercury in the U.S. comes from eating fish.
- Mercury emissions are a global problem.
- Controlling air emissions is one component in the overall effort to reduce mercury exposure.

Mr. Bauer noted that Asia has over 50% of the mercury emissions in the world. North America only has about 9%. **Representative Smith** asked if any of the mercury that is emitted in China has been detected in Idaho. **Mr. Bauer** said it is very difficult to monitor an emission and determine exactly where it comes from. It is known that mercury gets up into the atmosphere and circles the globe. There is no data that shows where Idaho's mercury is coming from.

Representative Andrus asked if Idaho has a mercury standard. **Mr. Bauer** stated that Idaho does not have a standard but there is a screening emission limit for mercury and it is in our toxic air pollutants.

Representative Smith asked if Idaho has heard from the EPA on applying for an extension of the November deadline. **Mr. Bauer** said no but the rule is under reconsideration and depending on when that is completed, the deadline may have to be extended.

His presentation includes a chart giving an overview of where U.S. mercury emissions were coming from in 2001. It shows that almost 50% of the mercury emissions in the U.S. are coming from coal fired utilities.

Mr. Bauer explained that there are two parts to the Clean Air Mercury Rule (CAMR). It has a stack emission limit on mercury for new sources that are built after January 2004. The second phase of this is that there is a cap-and-trade on the mercury where nationally there are goals to reduce emissions of mercury by 21% by 2010 and by 70%

by 2018. This establishes a national priority to reduce emissions as well as to state specific caps. The rule also requires monitoring of emissions from the stack and this is the first time that has been required. Mercury emission caps today are about 50 tons nationally and by 2010 the country wants to be down around the high 30s and down to around 15 by 2018.

Idaho was one of four states that were allotted a zero percent mercury cap. This is due to the fact that the cap was based on the amount of commercial coal fired power generation in the state and Idaho has none.

Mr. Bauer went on to discuss the three options available regarding the cap-and-trade program.

- **Plan A: EPA has created a model rule and set up a national trading program.**
  - States can adopt the model rule through incorporation of the rule into state standards and then participate in the EPA-administered trading program.

This means Idaho could opt into this program and allow the EPA to administer the trading program.

  - States can customize the allocation methodology of the model rule into a state rule and then participate in the EPA-run trading program.

This option allows Idaho to opt into the program and write a state-customized rule limiting the trading of mercury up to a certain limit that would be more specific to Idaho's needs.

- **Plan B: Establish state emission limitations to keep total emissions under the state budget**.
  - The state budget is a hard cap.

Mr. Bauer said many of the western states are doing this, including Arizona and Colorado, that have plenty of emissions. This is interesting for Idaho because our cap is zero. By opting into this plan we would be saying the state does not want any mercury emissions and would be limiting the amount of coal fired generation that could come into the state.

- **Plan C: Do nothing.**
  - EPA will automatically opt the state into the trading program.

Mr. Bauer went on to discuss the Idaho process (where we have been, where we are and where we are going) as follows:

- <u>August 3, 2005</u>, Clean Air Mercury Rule went out to public comment.
- <u>October 5, 2005</u>, Comment period extended until 10/26/05.
- <u>October 21, 2005</u>, DEQ was notified that EPA was reconsidering the rule so DEQ withdrew proposed CAMR.

Mr. Bauer explained that when DEQ did this, they withdrew Idaho's incorporation of that rule into state rules. This took both the stack emission section and the cap-and-trade off the table and Idaho is currently not dealing with that rule.

- Process is on hold until EPA's reconsideration is final.

Mr. Bauer said he has heard that this should be finalized in May or June of this year. If this happens, there is a deadline for Idaho in November 2006 to decide what we are going to do. There has to be a plan and the state has to notify the EPA of whether we are going to opt in and to which option. If the reconsideration takes longer than May or June, EPA will need to move the November deadline back so states will have a chance to look at what the rule says and make a decision based on that.

Senator Kelly asked what type of scientific or economic analysis was done by DEQ before they decided whether or not to propose to opt into the program. **Mr. Bauer** explained that since this was a federal rule being adopted by reference, no scientific analysis was done. The EPA had done all of that in order to show how the reduction was going to made.

Representative Stevenson asked whether this applies only to new facilities. **Mr. Bauer** stated that the stack emission limit only applies to new facilities, but the cap-and-trade applies to all existing and new sources.

The next steps:

- When reconsideration is final, DEQ will brief the Governor on the federal rule.
- Determination by the Governor for a proposed state rule (i.e. opt in or opt out of trading program) will be made.
- DEQ will go out for public comment.
- Currently there is a November deadline for States to opt in or opt out of the Cap-and-Trade
- Comments will be taken and a final proposed rule will be drafted.
- Proposed rule will go before the DEQ Board.
- If approved by the Board, the rule will move forward to the Legislature for final approval.

Senator Kelly asked if DEQ plans to change their approach as to how they decide whether to opt in or out of the program. **Senator Hill** asked for an explanation of the pros and cons of opting in and out also. **Mr. Bauer** said they are going to change their approach and are in the process of developing a lot of data on mercury deposition, wet/dry and fish tissue samples from the water standpoint. He said, in his opinion, all of this needs to be presented to the Governor, including the fact that this rule is coming along, so he has a good picture of the entire mercury issue that exists before a decision is made.

Mr. Bauer, with regard to **Senator Hill's** question regarding the pros and cons or consequences of opting in or out, stated that if Idaho chooses to opt out of the program, we are saying that we will live with the hard cap of zero mercury emissions. We would be saying the state is not interested in having coal fired power generation that emits mercury. If we opt in to the program under the federal program, we are saying the state is interested in growth of the coal fired power industry in Idaho. Under this program, Idaho will have to seek credits elsewhere in the United States with another state that is part of this program to allow any growth in Idaho because we have to show a zero cap at the end. In other words, if the state's mercury emissions are going to increase by ten, the industry has to purchase ten credits to balance that out. He said under this program the only limit to emissions is whether the credits are available to purchase. He said the market for credits has not been established yet and probably will not be in effect until 2010, but he did not think they would be cheap.

Mr. Bauer noted that the state can also opt in under a more state specific program. This would say that Idaho is interested in having coal powered generation in the state but maybe only a certain amount.

In response to another question from **Senator Hill** regarding who the credits are purchased from, **Mr. Bauer** stated that under the federal program the EPA will actually be the administrator and he would assume that the money goes back to the state selling the credit. It could also go back to the utility.

Representative Anderson commented that the United States has actually less than 1% of the world mercury emissions and that 62% of that 1% comes from natural occurring sources such as forest fires. He noted that the geothermal features at Yellowstone National Park produce more mercury than all of Wyoming's eight coal fired power plants.

Representative Eskridge asked whether Idaho has penalized itself by not having any coal fired power plants resulting in the zero cap on mercury emissions. It is his understanding that due to that, the only way Idaho can develop a coal plant is to buy credits, whereas if the state had a coal plant, we would have gained credits by modernizing that coal plant and reducing its emissions. **Mr. Bauer** said that depends on what perspective you are looking at the issue from. **Representative Eskridge** said that, in his opinion, Idaho has been penalized because we will have to buy credits in order to build a coal fired plant and the state also has no credits to sell. This will increase the cost of coal generation in the state. **Mr. Bauer** said it is correct that Idaho does not have anything to trade. He noted that there are other states out there that have things to trade that have said they are not going to trade them anyway. There are states that have a higher cap that are not going to enter into the cap-and-trade program. He also said that because we have a zero cap, the state has no room for growth without purchasing. **Senator Kelly** commented that the reason the federal cap and trade program exists for mercury is because it is a toxic emission that can have public health consequences.

Senator Kelly noted that DEQ has authority to adopt temporary rules that become immediately effective upon adoption without a public comment period and without the Legislature's participation. She asked if there is a chance that DEQ is going to opt in or out of the cap and trade program via a temporary rule. **Mr. Bauer** said that at this time, DEQ is going with a proposed rule, not a temporary rule.

Representative Jaquet asked who would be on the negotiated rulemaking body. **Mr. Bauer** said negotiated rulemaking meetings are open meetings and are open to anyone who is interested.

Mr. Bauer continued on with more information regarding particulate matter. He stated that EPA is proposing the following standard changes:

- Currently 65 ug/m^3 – 24 hour basis
- Proposing 35 ug/m^3 – 24 hour basis
- Proposing no change to the annual standard of 15 ug/m3
- Final Standard due September 27, 2006

For Idaho this means that the Treasure Valley, Coeur d'Alene, Preston and the Cassia Valley are potential nonattainment areas. This needs to be kept in mind, as the state decides whether it wants coal fired power generations or a large emission source, as to where that would be located. It would probably not make a lot of sense to put such a thing next to an area that has already been identified as a potential particulate matter problem area even though the rules do allow it.

In response to a question from **Representative Stevenson, Mr. Bauer** said that if these areas go nonattainment, the state will have to do a maintenance plan that will include all sources and everyone will have to do their share to get the area under the set standard. He emphasized that these are proposed standards that are still out for public comment. He said he is very sure once they are final, there will be litigation so this could not happen for many years.

Mr. Bauer stated that by the year 2064, the state wants to be in an area where the regional haze and visibility in our federal class I areas is back to its natural background. In Idaho these areas include Craters of the Moon, the Sawtooths, Hells Canyon, the Bitterroots and Yellowstone. He noted that locating a large plant within 50 miles of these areas might also cause Idaho additional problems in trying to reach these requirements.

Senator Hill asked whether DEQ already takes these issues into consideration in issuing permits for energy facilities or is it something the Legislature should consider as a policy. **Mr. Bauer** said DEQ does look at this but their authority is not that strong in these areas. Under the permitting program a large source is required to do a visibility analysis in any federal class I area, that is all. They submit the analysis and say yes or no as to whether it will impact the area. There is no rule that says if the impact is over a certain amount, the permit must be denied.

Mr. Bauer went on to say that greenhouse gases and climate change are going to be the next big issues. This is already true in many parts of the world. Currently in the U.S., ten northeastern states have voluntarily established a carbon dioxide registry that is basically an emissions inventory. These states want to turn that into a cap-and-trade program on greenhouse gases. There is also a southwest climate change initiative that includes Arizona and New Mexico that says they will start looking at greenhouse gases and what is being emitted. Idaho currently has a carbon sequestration committee that is trying to develop areas that are conducive to getting rid of carbon dioxide. This is a potential income for Idaho.

In response to a question from **Senator Kelly**, **Mr. Bauer** explained that in order for a facility to be issued a permit by DEQ for air quality, they must show that they can comply with the national ambient air quality standards, meet all emissions standards, including toxic air pollutants (TAPs) and must demonstrate best available control technology. If the source shows they can meet these requirements, DEQ is required to issue a permit, no matter where the source has decided they want to locate.

Senator Gannon asked how many applications per year DEQ gets for these permits. **Mr. Bauer** said for a larger permit not very many; five in ten years is a lot. **Senator Gannon** asked for an example of a non-coal fired plant application for a permit. **Mr. Bauer** said several years ago a natural gas fired plant wanted to locate in Canyon County (Garnet); that would be considered a large source. There are many existing large sources in Idaho.

Representative Anderson asked whether a wood fired cogeneration power plant would be required to get a permit. **Mr. Bauer** said such a plant would need a permit but the type of permit required would depend on how large the plant was. **Representative Anderson** commented that it is his understanding that the burning of wood is just as much of a mercury emitter as coal. **Mr. Bauer** said the permit is not just based on mercury emissions, it is based on criteria pollutants including nitrogen oxide, sulfur dioxide, carbon monoxide and so on. A wood fired plant would not be required to meet the federal mercury levels because that only deals with coal fired plants, but they would still be required to meet our TAPs.

Representative Andrus asked whether coal fired gasification plants emit mercury. **Mr. Bauer** said he has not seen an application for a coal fired gasification plant. Speaking from what he has been told by companies interested in this, they are claiming that the decrease they can get and the efficiencies are very large compared to pulverized coal. They still emit mercury but a much smaller amount.

Representative Eskridge asked what the percentage of the world mercury emission is from U.S. coal plants. **Representative Anderson** said less than 1% of the world mercury emissions are produced by United States power plants. **Representative Eskridge** commented that while the United States is contributing less than 1% of the mercury emissions from coal plants, we are incurring a large amount of expense to coal fired energy producers in the U.S., adding to the cost of production in terms of goods and services the country competes with in the world market, while Asia contributes 53% of the mercury and is going to continue increasing their emissions without spending money to reduce, allowing their goods and services to be produced at less cost. **Representative Anderson** added that of the 9% total emissions in North America, 8% is from Canada and Mexico and 1% is from the U.S. **Representative Jaquet** said that she has visited China and agrees that they have very bad air quality and terrible haze. In her opinion, the U. S. still needs to make an effort and set a good example and develop new technologies that will make us competitive in the world markets. **Representative Eskridge** said he would hope this would change before the U.S. loses the ability to compete in the world market and becomes a secondary power. **Representative Jaquet** said that the President of China is in Seattle and with the Olympics being held in Beijing they are concerned about cleaning their air. She said that Washington State is going to be selling China a lot of technology to help clean this up. She said she is optimistic that we are moving in the right direction.

Senator Hill said that at a future meeting he would like to hear from DEQ as to whether there are things they would like to see in a statewide energy plan that from a policy perspective would help the agency in the determinations and decisions they make.

Day one of the meeting recessed at 4:55 p.m.

Day two of the meeting was called to order at 8:00 a.m. on Thursday, April 20, 2006.

Mr. Barry Burnell, Water Quality Division Administrator for DEQ, was introduced to discuss water quality permitting requirements for industrial facilities. His complete powerpoint presentation is available at the Legislative Services Office.

Mr. Burnell said that in talking about coal fired power plants, water use comparisons need to be looked at. In comparing a pulverized coal (PC) plant to an integrated gasification combined cycle (IGCC) plant, an IGCC plant uses about 35% less water and produces about 33% less wastewater. He said that wastewater is something that will have to be dealt with as part of water quality permitting. Depending on how much treatment a facility wants to provide, there are several different options for wastewater available. These range from the total containment in evaporative ponds to surface water discharge if an EPA permit is granted.

Mr. Burnell said that there are three types of geothermal power plants: dry steam, flash steam and binary cycle. He stated that there is a proposed project in the Raft River area that is looking at a binary cycle plant. Geothermal plants involve cooling waters, noncontact cooling waters and “blow down” that involves essentially using water to cleanse the towers and this blow down water would be part of the wastewater stream.

Mr. Burnell’s presentation included a slide showing the makeup of a geothermal plant. He commented that storm water plays a role, as does the need for a public water supply and sanitary wastewater treatment facility to process wastewater.

Senator McKenzie asked about the size and type of the geothermal plant being planned for Idaho and its lifespan. **Mr. Burnell** said it is his understanding that it is a 30 megawatt facility in three stages of ten megawatts each. He said he has not heard of a cap on the lifespan of a geothermal facility. He noted that the proposed Idaho plant is not planning on reinjecting the geothermal back into an injection well. They would like to use that water for agricultural purposes. This will require that it be cooled down and, in some cases, different types of contaminants such as total dissolved solids, iron and so on, that will have to be dealt with. **Mr. Burnell** said that DEQ’s role in this is to look at whether or not there is going to be recharge to a shallow aquifer and, if so, certain water quality standards come into play. Essentially a monitoring program would be developed for that activity. Also our groundwater quality rules require using best practical methods and best management practices so that the groundwater does not get contaminated.

DEQ has authority with regard to water quality permitting when dealing with process wastewater, drinking water systems and sanitary wastewater. DEQ does not deal with storm water of underground injections. Storm water from geothermal power plants is controlled either by the NPDES General Permit issued by the EPA or if it is not being discharged to surface water, it is controlled by the Idaho Department of Water Resources Underground Injection Control (UIC) Well Permit. Reinjection is also under the UIC program.

In permitting process wastewater, these options exist:

C Discharge to existing permitted sewer system
C Permitted Issued under DEQ Authority
  C Subsurface Sewage Rules (IDAPA 58.01.03)
  C Reuse Rules (IDAPA 58.01.17), or
C Total Containment – Lagoons/Evaporation
C Discharge to surface water
  C NPDES permit -- EPA
C Treatment

DEQ has been told that the preferred method for wastewater blow down is to store it in evaporated and lined wastewater ponds. So far DEQ's wastewater rules do not include the use of nonmunicipal types of wastewater systems. Currently the design of a nonmunicipal facility is essentially based on the best professional judgment of the design engineer. There are not really any specific design standards that the agency uses. He said DEQ recommends the use standards that are being developed for municipal systems, but they are not required. In his opinion, this could result in some problems. **Mr. Bauer** said he foresees the need with these types of facilities for specific testing of the wastewater pond. In his opinion, as more large facilities are constructed around the state, it is important that a third party engineering firm is doing the construction inspections and is present to make sure the installation is being done according to the design plans. He used the example of Burlington Northern and said if there had been a third party on-site to witness the construction of that facility, it would have prevented a lot of problems. There is a cost associated with a third party oversight, but it is cheaper than having to go back and correct a mistake.

Senator Kelly asked for clarification that there was a decision made at DEQ to not regulate nonmunicipal wastewater facilities and the problem of not requiring third party oversight of a facility. **Mr. Burnell** said at the time that decision was made, the current water quality standards had some language that required the agency to do a plan and spec review of the disposal site of a nonmunicipal facility. That same language was put in the wastewater rule. He stated that DEQ has not decided whether to go forward with a rule to require a third party engineering firm be present. **Senator Kelly** commented that it would seem like now would be the time to establish this before there are actual applications pending and asked why they would not do this. **Mr. Burnell** said DEQ could, as part of the second round of facilities standards, have discussions and negotiated rulemaking about that. There has been some opposition to agencies having authority to make that a requirement. In his opinion, it is probably prudent during facility standards rulemaking to have those discussions to see if there is general consensus.

Senator Gannon asked what will happen if DEQ does not regulate nonmunicipal projects, will they be unregulated? **Mr. Burnell** said the current code puts the responsibility on the owner of the project to have it inspected and it is the responsibility of the design engineer to have some oversight and to produce, either as-built plans or a letter of construction saying the project is in compliance with the design. He said the practice has been that there are not always the best people on-site to observe the inspections. In some instances as-built plans or letters of construction are received saying the projects are in compliance and that is not always the case.

Representative Anderson said in his area part of the DEQ requirement for the outlet sewer district was for the engineering firm to have an on-site construction inspector. Due to this fact, he said he thought this was required for all projects. **Mr. Burnell** said that approvals issued by DEQ are conditioned and it is typical for such approvals to include language that states what the oversight will be. State law does not actually require that. He said most often the design engineering firms provide the oversight themselves. **Mr. Burnell** said in his opinion, for large facilities being built, it would be in best interest to have a third party engineering inspector on-site to make sure it is built appropriately. In looking a the large solid waste municipal facilities being built this is fairly typical. **Representative Anderson** asked whether it would be better to have a third party general contractor instead of an engineer. **Mr. Burnell** said that during construction and a design build, if there are any changes or modification to the design, it would be better to have engineering oversight.

The rest of **Mr. Burnell's** presentation covers all facilities and deals with drinking water systems and sanitary wastewater. He said in the previous energy plan, it talks about, in many sections, the infrastructure associated with large construction activities and associated surrounding towns. This means that if a surrounding town is on the edge of compliance for drinking water or wastewater and has a large influx of construction workers for a project, there is a chance that the infrastructure (drinking water and wastewater) will need to be upgraded.

Mr. Burnell said that part of the definition for a public drinking water system states that it serves an average of at least twenty-five individuals at least sixty days out of the year. This means that large construction sites that involve a few hundred people on-site will have a public drinking water system. Also, after the facility is constructed, if it has more than 25 workers, it will remain a public drinking water system.

The choices for drinking water systems are to connect to an existing public water system or to construct a new public water system. Construction of a new system involves well location siting approval, plans and specifications, well construction plan review, system design plan review and drinking water quality tests. He noted that 95% of Idaho's drinking water comes from ground water.

Mr. Burnell continued with the options for sanitary wastewater which is the wastewater for the workers during construction and operation. These include:

- Discharge to existing permitted sewer system
- Permits Issued under DEQ Authorities
- Subsurface Sewage Rules (IDAPA 58.01.03)
- Reuse Rules (IDAPA 58.01.17), or
- Discharge to surface water -- NPDES program permit -- EPA
- Designs based on Wastewater Rules (IDAPA 58.01.16)

Mr. Burnell said that city sewers or sewer districts, in order to accept the wastewater flow from a project, provide DEQ with a will-serve letter. This letter states that the city has the hydrologic capacity, treatment capacity and that they are willing to accept the wastewater. If a will-serve letter is not received, DEQ does not force a city or sewer district to accept a project. The last four items above are what would be required of a project if a city or sewer district does not accept its wastewater.

Representative Bell asked if the permitting process is adequate or more regulation is needed to protect the state as power generation is built. **Mr. Burnell** said that DEQ's position on industrial facilities has been that what happens in a facility is up to the facility. On the other hand, the point at which a facility needs to discharge wastewater to the environment, is where DEQ exercises its authority and steps in with regulations. The rules adopted to implement that authority are "bare bones" as far as specific requirements. This decision was made last November by the DEQ board. A lot of the discussion at that time was regarding lined facilities and wastewater ponds. There was no consensus that DEQ should have specific authority to require testing of facilities (seepage) or to have certain design criteria for those facilities. Currently DEQ relies on what the Idaho Code says in the plan and spec review and some general statements that were passed through from water quality standards to the wastewater rules. He said that DEQ does their best to work with facilities to make sure that removal of wastewater is handled in a manner that will not contaminate the environment.

Senator Kelly asked whether this means that industrial facilities are regulated less stringently than facilities that need to get rid of domestic sewage wastewater. **Mr. Burnell** said there are two different sets of regulations for municipal and nonmunicipal facilities. **Senator Kelly** asked if the wastewater from municipal facilities is more dangerous than industrial wastewater. **Mr. Burnell** said that in looking at sanitary wastewater they are typically concerned with the bacterial load that is present, the wastewater strength and other contaminants. Industrial wastewater facilities have many different types of contaminants because many different things are produced. It is very site specific based on industry.

Senator Kelly asked whether there are currently any applications pending at DEQ for energy facilities. **Mr. Burnell** said there is currently an application pending for a geothermal project in Raft River and they are working to identify the criteria that facility would need to meet. He said that the proposed coal gasification plant has not filed an application but that will be mostly air related. It is to be located at an existing facility so it would probably use an existing wastewater system. **Senator Kelly** commented that if this coal gasification facility chooses to use existing ponds for wastewater, it is her understand that they would be self-regulating as to the integrity of the system. If down the road ground water contamination is found because the ponds were not working properly, she asked whether DEQ would then regulate the facility. **Mr. Burnell** said he thought her statements were correct.

Senator Werk asked whether the Idaho Department of Water Resources will deal with storm water discharge in the situation of a major coal facility with fuel storage. **Mr. Burnell** said that DEQ does not have regulatory authority over facilities that choose to use underground injection control for storm water disposal. If storm water is to be discharged to surface water, EPA and NPDES authority and DEQ's role with that is to issue a Clean Water Act Section 401 Water Quality Certification that the discharge will meet Idaho's water quality standards.

Senator Werk asked if it would make sense to have a consolidated permitting oversight process with one agency in charge. **Mr. Burnell** said that "one stop shopping" is always good, but in his opinion the regulatory structure is not set up that way. **Senator Werk** commented that once the committee starts talking about consolidating, there is the issue of whether the state would want to take primacy over the NPDES process in dealing with discharge to surface water. He said this is an issue of funding.

Representative Smith asked, once an application is received for the coal gasification plant in Pocatello, will DEQ deal with air quality issues and whether Idaho Department of Water Resources or the EPA will deal with water quality. **Mr. Burnell** said that will depend on how the facility decides to deal with storm water. If it is not a discharging system, DEQ would do the regulation.

Representative Eskridge asked, since a geothermal plant has already been proposed in Idaho, for clarification of the issues in terms of water and air quality. **Mr. Burnell** said the primary concern is that the proposed binary cycle plant uses a low boiling point compound. The geothermal source is around 270 degrees Fahrenheit. That source of hot water is pumped from the aquifer, it mixes in a closed heat exchanger with the boiling point compound, turns to vapor and drives the turbine. He said this is actually a closed loop system where the two cycles occur side by side and the water does not actually mix with the compound. Once the binary fluid flashes and goes through the turbines and produces the power it is still in the vapor stage. At this point it goes through a condenser that contains cooling water to cool down the binary fluid vapor and it condenses back into a liquid and gets reused. The cooling water that is used in the condenser heats up and that water ultimately has to be cooled itself. To cool that water, towers are used that blow air through the water to cool it for reuse. **Mr. Burnell** said this process causes wastewater issues because minerals accumulate in the cooling towers and that has to be cleaned out.

Representative Eskridge clarified that the cooling water is the wastewater we are concerned with. This water has minerals in it that are solidified and have to be discharged somewhere. **Mr. Burnell** agreed. The binary water is not a problem because it is a closed system. The geothermal water is not a problem either.

Representative Eskridge asked what the difference is between a geothermal plant and a coal plant in terms of wastewater and air emissions. **Mr. Burnell** explained that his understanding of coal plants is that the scrubbers in the towers that remove pollutants can be water based and those discharges would go to a total containment pond. He said it is really not cost-effective to treat this water to get it to a state where anything else could be done with it. The water in the containment ponds can be reused once it settles out.

Senator Werk said that a coal plant that has an external source of fuel, with piles of coal being stored around the plant also raises a surface water issue from the containment of storm water; while geothermal fuel is underground.

Representative Bell said she is still concerned about where the state is and asked if DEQ is where it needs to be to keep up with energy development and how other states handle this. **Mr. Burnell** said there are two areas of concern. He said it is pretty general because water and wastewater infrastructure of new facilities will affect cities and sewer and water districts. In looking to the future the state needs to be able to address those added capacity demands. For the new plants themselves, the permitting process from the water side is different than air quality. From a water quality perspective they look at storm water and processed wastewater; if the state sees a number of facilities in a short period of time there will be a demand on DEQ staff resources that will exceed what they can do.

Senator Gannon said he is not concerned about DEQ handling the number of applications that have been received; he is concerned that they might be overwhelmed by one specific application, that is the one from Sempra. He said that this Sempra application, before it was withdrawn, was going to include a significant amount of water use, water left over and storm water falling on slag piles causing contamination issues. He said that the Legislature was under the impression last year that DEQ and other regulatory agencies were in a position to handle the permitting process. He asked if the state has in place the capability to review a Sempra type application and protect the environment. **Mr. Burnell** said from a water quality perspective they look at plan and spec review for total containment ponds. He said the storm water issue is not DEQ's authority unless a plant is going to contain it. **Representative Eskridge** clarified that inasmuch as DEQ has responsibility regarding a particular site, they have the capability to handle it. **Mr. Burnell** said they would do the best they could and prioritize the projects as they come in. There is a 42-day time frame for DEQ to complete plan and spec reviews. Large projects will probably take longer to review. He said the time frame and amount of projects needing review might cause delays. **Representative Eskridge** noted that DEQ's concern is time frame, not the ability to protect the environment. He asked how vulnerable Idaho is if an application for a coal fired plant was received. **Mr. Burnell** said the new staff that DEQ has been appropriated will help with the timeliness of review and if a coal fired power plant were to come forward with an application, it would be put in the queue for review. He added that DEQ has the technical expertise required to look at an evaporative lagoon or pond for wastewater.

Representative Eskridge asked if DEQ can fulfill its authority regarding environmental oversight on the geothermal plant. **Mr. Burnell** said yes, they are working on what regulations the plant will have to comply with. This will be covered by both the ground water and wastewater rules.

Senator Hill asked if the permitting processes in DEQ to date are adequate to protect the environment and the public safety. **Mr. Burnell** said yes. In his opinion there could be improvement in the construction aspect regarding third party construction oversight. **Senator Hill** asked how that could be done. **Mr. Burnell** said he would require independent third party inspection engineer oversight of projects. This would require constant oversight by qualified individuals to administer and oversee the construction to make sure the plant is being installed and constructed according to the design plan.

Senator Werk commented that the siting facility issue had to do with the land use decision for the plant and that communities downwind may not have had a voice in that process.

Senator Werk asked if industries have to pay fees to agencies for permits to be issued. **Mr. Burnell** said there are no fees to conduct plan and spec review or for wastewater land application permits. The delivery of a subsurface sewage program is fee-based but that is not really applicable here. He said the agency has two other fees; one for drinking water systems and one that is associated with the state revolving fund. These are loan programs for water and drinking water to offset the interest rate. **Senator Werk** requested more information regarding the fee structure.

Representative Nonini commented that regarding the requirement of third party inspection oversight in some cases these issues or problems should be noticed by the actual construction foremen. He asked what DEQ's role was during the construction of Burlington Northern's refueling facility. He noted that they now have a full-time DEQ employee on site. **Mr. Burnell** said the agency does not have inspection oversight responsibilities although they do go out and observe at times. He said their responsibility is to conduct the plan and spec review and to approve the plans. Inspection responsibility lies with the project owner and design engineer that did the design.

Representative Stevenson asked whether requirement of third party inspection could be implemented through rules by DEQ or would it require legislation. **Mr. Burnell** said that it could be either way. Currently it is in statute and so it would probably be best to change the statute. **Representative Stevenson** commented that rules are generally used instead of statute because agencies can adjust rules if necessary. He asked if rules might be better in this case, due to the fact that some changes will probably be necessary down the road. **Mr. Burnell** said, in his opinion, putting general criteria in the statute with the authority to adopt a rule would be very effective.

Senator Gannon asked if DEQ is equipped to make sure a project is in compliance after they begin operations. According to **Mr. Burnell,** the drinking water program would be prepared. With wastewater, he thinks industry would be well served to have licensed operators running the drinking and wastewater systems. He said that on the compliance side, there is air, water and waste and the state has inspectors who handle this.

Senator Gannon commented that DEQ has the ability to hold cities hostage for arsenic, but, in his opinion, that does not seem to be the case for industry. He asked how DEQ monitors holding ponds of projects to be sure they are not polluting the aquifer. **Mr. Burnell** said they rely on ground water monitoring of those wells. He added that currently there is no requirement that those ponds have seepage testing. **Senator Gannon** asked if such a requirement for seepage testing or routine checking of these wastewater ponds needs to be legislated. **Mr. Burnell** said that the point of construction is when a pond's integrity is tested. Post construction, DEQ has no authority to require any routine seepage testing on nonmunicipal facilities. He said that DEQ could change that through rulemaking. This would require consensus with industry partners and with legislative approval.

Representative Andrus clarified that DEQ has no responsibility during construction of a nonmunicipal facility, the responsibility is just in permitting. He asked who is responsible to sign off that the plants are ready to go and the environment is protected. **Mr. Burnell** explained that from a water quality perspective, the design engineer or project owner is responsible to certify to the agency through a letter of certification. This letter states that construction occurred according to the original design plans and requirements. An inspection of a facility by a third party engineer is another way for a facility to be approved. Plans are also submitted to DEQ so they have a record of how facilities are constructed. **Representative Andrus** asked what are the consequences if the owner does not meet these requirements? **Mr. Burnell** said that they are required to submit this letter to DEQ 30 days after construction is completed. If they miss the deadline there is a $10,000 fine or $1,000 per day, depending upon the extent of the violation.

Representative Anderson said that he has participated in two different sewer district constructions as a board member. His observation is that he thinks the request for a third party review is more to protect DEQ and their liability in review. One of the sewer districts he participated in was required to have ground water monitoring around the lagoon but the other one was not. There seems to be some inconsistency. He suggested looking at other states and how they have dealt with coal fired and geothermal plants and use their expertise. **Mr. Burnell** disagreed that his request for a third party review was to protect DEQ. In his opinion this oversight is to protect the environment. **Mr. Burnell** stated that inspection oversight provides additional protection to the environment. **Representative Anderson** commented that as-builts oftentimes contain design flaws that were requested by DEQ and several as-built cost his districts a lot of money that were actual errors of engineers in the department. He wanted that to be acknowledged because the ratepayers eventually pay for this.

Senator Kelly said what she is hearing from the head of the Water Quality Division of DEQ is that there are some areas where Idaho law can be reinforced to better protect public health and the environment. She suggested that the committee look closely at this.

Representative Eskridge requested that DEQ go back and look at the siting of energy facilities in Idaho and document what their responsibilities are currently, how they are met and what is needed additionally to deal specifically with energy facilities (all types) and the water quality issues involved. He said he agrees with **Senator Gannon** and that he was also under the impression that requirements were in place to protect the environment of the state.

Mr. Jim Kempton, Northwest Power and Conservation Council (NWPPC) was introduced as the next speaker. He explained that the NWPPC is made up of four states: Washington, Oregon, Montana and Idaho. He said the staff are experts in all areas. He introduced **Dr. Terry Morlan, Power Division Director and Mr. Jeff King, Senior Staff Analyst, who specialize in power generated resources. Mr. Kempton** said that because the council is a sort of apex of issues that occur in all four states, they have a good sense of such issues as this interim committee is currently discussing and can give a lot of assistance.

Mr. Kempton said the NWPPC had its origin in the 1980 Northwest Electric Power Planning Conservation Act. As a result of that, conservation is a very important issue for them. The council has two major charges. The first is to assure in the planning process an adequate, efficient, economical and reliable power system while at the same time protecting, mitigating and enhancing fish and wildlife because of the impacts of the Federal Columbia River Power System. He said in a sense these two charges conflict with each other. The council also has a requirement in the power act to forecast demand in the region twenty years out. He noted that this is very difficult to do and that amazingly the council has been very close to the mark up to this point. **Mr. Kempton** distributed a copy of the Fifth Northwest Electric Power and Conservation Plan. This is available at: www.nwcouncil.org. **Mr. Kempton** explained that the council will look at this plan on a two-year basis and if the forecasts are off, the plan can be adjusted and changed.

In forecasting the demand 20 years out, resources must be acquired to meet that demand. In order to do this the council does a resource analysis. He said that act itself gives the council priorities in terms of acquiring these resources. The highest priority resource is conservation. The second priority is renewable resources. **Mr. Kempton** stated that in their planning process, they try not to step in IRPs of other utilities. He also said that renewable resources sometimes require consideration of other generating resources that are not necessarily renewable. Their next priority is efficient generating fuels. This looks at the cost-effectiveness of natural gas, coal, waste heat and so on.

Dr. Terry Morlan was introduced to continue the NWPPC presentation. He commented that the council feels that this Northwest Electric Power and Conservation Plan has a lot of relevance to all of the states in the region. The western electricity system is an integrative whole and there is an interesting context between regional west wide regulations and activities and individual state policies with regard to power. The goal of this power plan is to help assure an adequate, efficient, economical and reliable power system. He said this plan is trying to identify a robust, flexible plan for managing power system costs and risks in the face of future uncertainty. This is a result of the 2000-2001 electricity crisis. This crisis made it very clear that there is a lot of volatility and uncertainty involved in the planning of energy. **Dr. Morlan** summarized the plan as follows:

- Aggressive, sustained development of conservation
- Confirm and develop demand response resource
- Near-term commercial scale development of wind to confirm costs, availability
- Be prepared to begin construction of:
    - Significant additional wind 2010;
    - Integrated Coal Gasification Combustion Turbines 2012;
    - Gas-fired generation late in planning period
- Address key policy issues
    - Adequacy standards
    - Transmission
    - BPA future role

Dr. Morlan explained that the plan deals with a resource called demand response for the first time. What was demonstrated in the process of the 2000-2001 energy crisis was that when electricity prices become very volatile, there is almost no limit to how high they can go. This is because there is no demand response, demand does not go down in the short term. Demand response is an attempt to develop voluntary agreements with industry and other consumers to cut back consumption of electricity when the price reaches a certain level.

Dr. Morlan said before the Power Act in 1980, electricity demand was growing about 5% a year in the region. After the Power Act it dropped to 1.2% a year. One reason for this is what happened to electricity prices. The higher electricity prices also damaged electricity intensive industries in the region; mainly aluminum. This industry accounted for up to 20% of all the electricity consumption in the region.

Representative Eskridge asked how conservation compares to actual loss of load with direct service industries (DSI's). **Dr. Morlan** said in his opinion they are very comparable during this time period. He stated that conservation savings is not the loss of aluminum plants or DSIs, it is through improved efficiency of homes and energy using equipment. His presentation includes a slide showing conservation of government utility programs, federal programs and so on.

Dr. Morlan stated that the point is that improved energy efficiency of use has played a big role in meeting the energy needs of the region over the last 20 years and in the plan it continues to be a very attractive alternative. It is cost-effective and also deals with risk and uncertainty.

Existing generation in the region is dominated by hydroelectric systems; natural gas and coal sharing the second most dominate source. The power plan looked at what the resource balance with the load in the region was with demand for electricity. They found that in 2004 the region was significantly surplus in generating capability and that existing capacity appears adequate to support loads through 2010 or longer.

Dr. Morlan gave the following overview of the planning process:

- C Identify and quantify key **Uncertainties**
  ***** Loads ***** Hydro conditions ***** Fuel prices
  ***** Controls on CO_2 emissions ***** Forced outages
  * Market price of electricity
- C Evaluate cost of operating and expanding power system for 1000+ ***Plans*** over 750 *Futures*
  * *Plans* – amounts and types of resources and when to be prepared to start construction
  * *Futures* – scenarios that combine the key uncertainties over the 20 year planning period
- C Seek out plans that minimize average costs for given level of ***Risk*** (expensive outcomes)

"Futures" are defined by probabilistically modeled uncertainties including:

- C Hydro generation
  - *Annual variation
  - *Fish constraints
  - *Climate change effects
- C Electricity loads
- C Natural gas prices
- C Electricity market prices
- C Global climate change policy (CO_2 control timing & costs)
- C Resource availability (forced outages)
- C Technology development
  - *Cost reduction, performance improvement
- C Resource incentives
  - *Production tax credit
  - *Renewable energy credits (Green tags)

His presentation also includes slides showing a demand forecast for growth at 1.5% per year before conservation, natural gas price history and the revised forecast and example risk treatment.

Senator Gannon asked how conservation is measured. **Dr. Morlan** said that for any given measure that is taken, they look at the technical possibilities of how much energy that would save in a refrigerator (for example). It is known that certain new refrigerators will save a number of kilowatts per year over older conventional ones. Some estimates are made about how many new refrigerators will be brought in and the limits to how much penetration of those there will actually be. Those factors are added up to get a total number of kilowatt hours that are then converted into average megawatts. **Senator Gannon** asked how they measure how many refrigerators have actually been converted. **Dr. Morlan** said these are projections. He said they also verify with industries whether the goals are being achieved. **Senator Gannon** asked if the council was actually implementing a plan that was creating conservation. From this discussion it would seem that they are just forecasting based on refrigerators and other outcomes. **Dr. Morlan** said the plan is a forward looking plan that is forecasting total electricity need and how much of it will be in commercial buildings, residential, industrial and irrigation. The whole plan is a forecast and analysis of what is the best way to meet growing electricity needs in the region. When the plan is implemented, they try to track whether or not the plan met its goals.

Dr. Morlan introduced **Mr. Jeff King** to complete the presentation. His part of the presentation shifted to resources. **Mr. King** said that in their world, resources mean generating resources: coal plants, geothermal plants, wind plants; and it also means conservation resources: more efficient refrigerators, energy efficient light bulbs.

Mr. King stated that the resources are selected using the council's portfolio assessment model. This model:
- C Evaluates many (~1000) of alternative plans over many (750) plausible Futures

For each plan, the model calculates:
- C System Cost (average "going forward" power system cost)
- C System Risk (average of the 10% most costly outcomes)
- C Feasibility Space
- C Efficient Frontier

The model seeks the least cost plan for a given level of risk. His presentation included this table showing resource performance versus selected risk factors.

	Fuel Cost	Load Uncertainty	CO_2
Conservation	No fuel required	Short lead time if programs are sustained. Positive correlation to load.	No CO_2 production
Wind	No fuel required	Short lead time of sites are permitted & turbines are available; certain reliability	No CO_2 production
Coal-steam	Abundant, low-cost fuel; somewhat uncertain rail cost	Long lead time; certain reliability	High CO_2 production; high control cost
Coal gasification combined-cycle	Abundant, low-cost fuel; somewhat uncertain rail cost	Long lead time; uncertain reliability	High CO_2 production; moderate control cost
Natural gas combined-cycle	Volatile & uncertain fuel cost	Moderate lead time; certain reliability	Moderate CO_2 production; high control cost

Senator Gannon asked about uncertain reliability for coal gasification. He had read a report that investigated three coal gasification projects that have failed or did not work. He asked if that is why that is shown as uncertain. **Mr. King** stated that the technology of converting coal or other solid fuels into synthesis gas is a very old technology from the 1800s. The problem is that using this to generate electric power requires a very complex power plant and requires technologies to be used together that have not been used together in the past. It is very hard to integrate.

Representative Eskridge asked whether using coal slurry as a way to get coal delivered to plants has been considered over rail transport. **Mr. King** said that was considered in the 1970s and only one plant in the U. S. was constructed to use it. It works, but the issue is water usage. Coal gasification plants are limited in the amount of water the coal can accept.

Mr. King went on to discuss the NWPPC's recommended resource portfolio. He said this is noted as expected buildout because their recommendations are not specific that a state should build a specific coal gasification plant in a specific year; their recommendations are that a state should be prepared to build such a plant in that year. There is uncertainty about how fast loads will grow and how fast other resources will be developed. He said "prepared to build" is the optimal situation. This would mean that a site has been selected, fully permitted, feasibility studies completed, equipment vendors identified, plans made on financing, the utility or resource developer in charge and so on. Then when the need materializes, construction can proceed. **Mr. King** said the council has advocated this approach ever since the first power plan in 1983 and it has had an opportunity to be tested when energy prices went up in 2000. There were several plants that were ready to go in the northwest and those were the first plants to come online and helped dampen down some of the effects of that energy crisis.

Mr. King's presentation includes a slide showing the recommended resource portfolio. This consists of:

- a very substantial amount of conservation (2,700-2,800 megawatts)
- committed renewable and cogeneration resources

He said these are resources the council is very confident will be developed because of current utility resource acquisition activity and state system benefit charge programs that incentivize renewables.

- gas fired plants that were under construction at the time the plan was developed so they are committed
- wind power (5,000 megawatts)

This is the first time wind power has appeared in a power plan. That potential is there and, in **Mr. King's** opinion, is being developed faster than the council anticipated.

- a coal gasification combined-cycle plant
- gas fired resources

Mr. King said to some extent the reason these gas fired resources are included is due to the fact that conservation and wind resources were limited to an amount the council felt could actually be developed over the next 20 years. Many of these modeling runs ran out of conservation and/or wind before the 20 years was up and had to turn to another resource.

- demand response resources

This involves agreement with power users that would enable voluntary curtailment if necessary.

Senator McKenzie commented that of current generation, nuclear power is about 2% and no expansion has been seen in this period of time. **Mr. King** said that was correct. He said that nuclear power was considered but the conclusion was that the first of the next generation of plants will be completed in 2015 or so. He sees most of those being built in the southeast U.S. He said there is a provision for a plant at INL that appeared in the 2005 energy policy act that was not in existence at the time the council's plan was completed. The thinking was that a utility in the northwest would want to see these new nuclear plants operate for a few years before building one.

Senator Hill asked if the recommended portfolio is a projection of what the council thinks will happen or is it an actual recommendation. If it is an actual recommendation, to whom do they make those to? **Mr. King** said these are specific recommendations that underlie this. He said the recommendations vary as to whether it is generation or conservation. In terms of conservation, there are specific recommendations with respect to annual conservation acquisition targets. That recommendation is 700 megawatts over the next five years. With respect to generation resources the basic recommendation is to be prepared to build certain types of plants by a certain year. **Mr. King** said there are some collaborations with some recommendations such as the recommendation to build, regionwide, at least 100 megawatts of wind power per year at diverse geographic locations so we can understand and feel more confident in having 5,000 megawatts of potential wind power. **Mr. King** stated that the council has no direct authority except for an authority over BPA acquiring resources of 50 megawatts or greater, but it is unlikely that this will ever happen. The council does have persuasive authority and they do an open analysis data acquisition process that is unlike utilities or independent resource developers. The council's process is totally open to the public and people do participate. This is an attempt to build confidence in the analysis so that utilities will use the council's recommendations when completing their IRPs.

Senator Hill asked how the council is funded. **Mr. King** said the majority of their funding comes from a certain percentage of BPA's firm power sales. Essentially, with any BPA firm power that ends up being used, a small piece of the payment by the utility that used the power goes to the NWPPC. There is also some supplementary funding for special projects.

Senator McKenzie asked how the council's recommendations are reflected in the utility IRPs. **Mr. King** said the council does look at all utility IRPs to see how close those come to implementing recommendations. He added that someone from the council sits on each advisory group for all of the major utilities in the region. That is their principal interface with the utilities.

Senator Gannon asked if there are other power councils like this across the country. **Mr. King** said he thinks this council is unique in terms of the total scope of their planning process. He said the closest would be the California Energy Commission.

Representative Eskridge clarified that the NWPPC was originally formed by the federal government to help plan resource acquisitions and conservation activities due to the anticipated deficits that BPA was going to face. **Mr. King** said that was his understanding of the original intent. **Dr. Morlan** said that the original act gave BPA the ability to acquire resources for the region and the council was established to give the state a say in what BPA decided to do.

In response to a question from **Senator Kelly, Mr. King** explained that BPA is a federal administrative agency that reports to the Department of Energy. It was formed to market the output of the federal dams that were constructed on the Columbia and Snake River systems. The dams are not owned by BPA, but it was decided that there needed to be another agency to sell the power from these dams. Their role was to build up a transmission system, move the power to customers and to sell wholesale power to customers with preference to publicly-owned utilities like cooperatives and municipalities. **Representative Eskridge** noted that while BPA is a federal agency, it is not an appropriated agency. It operates off of the revenues that it collects from sales of the federal power system. This pays the cost of operation, administration, power market facilities and repays back to the federal treasury money that was borrowed to build transmission and money that was used to develop conservation programs.

Senator Werk said that he noticed that the plan contains no recommendations of transmission and commented that this is an area that also needs to be focused on. **Mr. King** said the council has become more involved in transmission over the last few years, but there is a lot of discussion about how involved they should be in that.

Representative Eskridge asked how the continuing discussions regarding the nonfirm characteristics of wind plays into the council's resource analysis. **Mr. King** explained that wind operates in this region at about a 30% to 35% capacity factor. This means that the wind is an intermittent resource and it has to be shaped in order to meet load. In this area what comes out of the wind farm is not necessarily what is being consumed at the time. In California there is a really good coincidence of wind and load. That does not happen in the northwest, so wind has to be shaped. **Mr. King** stated that the council thinks the 5,000 megawatts they recommend can be shaped but that is not certain. He said that would be shaped using mostly the existing hydropower system because it would only be putting in and pulling off power for short periods. Toward the end of this power period, **Mr. King** said that thermal resources will have to be used for shaping.

Senator Kelly asked about the minor role of coal in the recommendations. She said that is somewhat inconsistent with the committee discussions and with Idaho Power's IRP. **Mr. King** explained that the council does a risk-based analysis to reach their recommendations. One thing they consider is the risk of the need for future regulation of CO_2. This would be mandatory and would cost money. He added that Idaho's circumstances are not completely reflective of the region. When the council looks at the region as a whole, Idaho has a much higher growth rate and so needs to get resources more quickly and that might be influencing Idaho Power's IRP.

Representative Eskridge said that this recommendation is for a large amount of wind power. He asked what the contingency plan is if the wind does not perform. **Mr. King** said that when the council selected 5,000 megawatts for the region, they brought together people from the wind industry and they were fairly confident that the industry could reasonably develop this much wind power. They also believed that could be shaped at a cost of less than about $10.00 a megawatt hour. He said there is always uncertainty. That is why the plan asks that 100 megawatts per year be built at different geographic locations in order to build confidence that wind will perform.

In response to a question from **Representative Andrus, Mr. King** commented that this committee needs to look specifically at the power needs of Idaho and the council will look at the region as a whole. Each state has its own specific needs and requirements. There are also transmission corridors that need to be considered.

Senator McKenzie commented that the committee needs to look beyond just electricity. He said Idaho's energy portfolio has 31% petroleum which is all nonrenewable and is all imported from outside of the state. In his opinion this is another important issue that needs to be considered.

Mr. Kempton noted that the NWPPC plan does not reduce this interim committee's role nor should the committee change its focus from the areas defined as important for Idaho. He added that any merchant power plant can come into Idaho and set up a power plant. That is what Sempra attempted to do. The Sempra issues are something that Idaho needs to focus on in the immediate future regardless of the projections in the NWPPC plan. The reason the council tries not to step in individual industry IRPs is because those planning processes in each of the state are going to differ depending on how those utilities have been built up, what the population demands are and what the acquisition to available power is in the region. Even though this region is surplus through about 2010, the question is does a utility have access to the additional power?

Senator Hill asked how does state policy affect the energy industry as the council has done their projections. He also asked for some guidance on what Idaho should watch out for in pursuing these policies. **Mr. Kempton** said that Washington and Oregon are far ahead of Idaho as far as conservation protocols and what they want to go forward with. He said, as an Idaho council member, he was very protective of Idaho and where the Legislature has put the state in terms of model conservation standards. The council plan is written with the idea that all four states would step up to the model conservation standard level for new construction. This meant that whatever state moved to the highest conservation standard, the other states would automatically go to that. Legislatures did not necessarily agree with that. Idaho submitted, through Governor Kempthorne, an exclusion to that. It stated that Idaho is proactive and recognizes the importance of conservation, but is not ready to accept conservation standards on a unilateral basis.

Mr. Kempton added that in his opinion this committee is on the right track in developing an energy policy. He said he thinks an energy plan is appropriate for Idaho, not only for the planning process but also how to integrate the different agencies to make them more efficient and to make them work together better. He said it is also important to recognize that conservation plays a significant part of power production for energy resources.

Representative Eskridge commented that the committee understands that the NWPPC has made a projection for the region and there are many things that will influence that projection in terms of how it actually plays out. He said Idaho is only one of many players in the plan and what is good for the region is not necessarily the way Idaho should go. By the same token, what the council looks at is very valuable to Idaho and this committee because of their expertise to look at different resource availabilities and the risk associated with those resources.

Representative Eskridge said the reason the relationship between the council and BPA was established was to set a guideline for resource acquisition by BPA to meet the resource needs of the region. He said that BPA has not been very successful in doing this with traditional resources. They have been instrumental in wind and conservation resources. He said that BPA may be allocated as a power supplier in the Pacific Northwest which leave our cooperatives and municipalities that receive power from BPA at the mercy of the market and it leaves them with the need to get into resource acquisition activities. **Representative Eskridge** asked if this was a correct observation. **Dr. Morlan** said yes. He said the utilities have recognized, as well as BPA and the council, that having BPA be the resource provider of last resort is not working very well. Changing BPA's role will take them out of the risk taker role for the region and if utilities want BPA to acquire certain resources for them, the utility will have to pay for the additional cost of those resources.

Representative Eskridge asked when the utilities look to BPA as the provider of last resort and given the difficulties BPA has had being successful in building conventional generation facilities, would those utilities be relying on long-term power purchases by BPA from other suppliers or would BPA actually develop resources. **Dr. Morlan** said, in his opinion, BPA would offer a variety of products including a market product of short, medium or long-term as well as a renewable product. He thinks many small utilities and cooperatives will say they are not in a position to acquire resources on their own and will still rely on BPA. As this policy is put in place, the utilities will find a lot of other alternatives.

Mr. Paige Parker, Legislative Services Office, was introduced to discuss a comparison of western state energy siting laws. This complete comparison is available in the Legislative Services Office. He explained that this comparison used statutory law only and did not look at other state regulations and there was no research done as to how well these practices actually work. **Mr. Parker** suggested that if the committee decides to go into a siting aspect of an energy plan, more in-depth research would need to be done. He used Arizona, Colorado, Idaho, Montana, Nevada, Oregon, Utah and Washington.

Mr. Parker explained that in terms of the agencies that oversee siting in these states it varies from Public Utilities Commissions, Departments of Environmental Quality to states that put together a sort of composite agency. His chart includes the composition of these authorities, their jurisdiction, what criteria they look at and the procedures they use.

Senator Werk asked how Public Utility Commission authority differs from state to state as far as their involvement in permitting for nonconsumer-owned utilities. He used the example of Colorado where a local decision can be appealed to their PUC. **Mr. Parker** said he has not looked at the specific jurisdiction of the different PUC's statutory analysis. In Colorado, it is a local zoning decision with an appeal to the PUC. He said he would assume that merchant plants would be covered, but he is not sure.

Senator Werk noted that in looking at the composition of the siting councils on the chart there are very few that have the local component involved. He said he found that interesting.

Mr. Parker commented that in the process of doing this comparison, he found a 1976 paper authored by C.C. Warnick, Idaho Water Resources Research Institute, titled "Methodology and Criteria for Siting Energy Plants in Idaho." This was a study that has some relevance today, although it does not include modern environmental issues that were discussed yesterday. It started off with the question "Where can we not site a plant in Idaho?" The areas identified included proximity to major population areas, buffer zones around certain areas, water availability, transportation facilities and so on. A link to this document is available on the Legislative Services Office website at: www.legislature.idaho.gov under the Energy, Environment and Technology Interim Committee.

Mr. Mike Nugent, Legislative Services Office, distributed the following URLs for other state energy plans:

- Illinois: www.aceee.org/conf/05ee/05eer_sfrenkel.pdf
- California: www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PD
- North California: www.energync.net/sep/docs/sep_12-04.pdf
- Nevada: http://dem.state.nv.us/sweep/htm
- Oregon: www.oregon.gov/energy/docs/EnergyPlan05.pdf
- Florida: www.dep.state.fl.us/energy/fla_energy/05energy.htm

Links to these plans are also available at: www.legislature.idaho.gov under the Energy, Environment and Technology Interim Committee section.

Mr. Nugent also distributed and discussed an e-mail that was received from **Mr. Bill Eastlake**, a retired member of the PUC. This e-mail states his concerns with how an energy plan will be created and what its intended use will be.

He cautioned that any real integrated energy plan needs to consider both conventional and alternative energy sources from gas, electricity, coal, nuclear and hydro to wind, solar and geothermal. He added that any good new plan should also consider energy sources that are NOT generation; e.g. conservation and demand-side management.

Mr. Eastlake suggested that since this plan is a justification for the "moratorium" on considering coal plants, it is important to consider whether some formal action resulting from the study is necessary. When one asks for a moratorium, it is usually to give one time to do something specific. He asked if "just making a report" is sufficient.

Mr. Eastlake's complete e-mail is available at the Legislative Services Office.

Representative Eskridge said the e-mail is very helpful. He stated that it was his understanding that the intent of this committee is to actually accomplish something and come up with a policy guideline recommendation to the Legislature and the Governor's office to adopt in terms of Idaho's energy future.

Senator Werk commented that outside of developing a plan, the committee needs to decide if there are other pieces of legislation necessary for follow-up and defining a committee stance to the rest of the legislature. In his opinion, there are things that could be done legislatively in association with the plan to make the plan an actual working document.

Representative Anderson said he sees four components under which the committee could work. These include generation, transmission, other fuels, transportation/fuel sources for transportation and conservation and demand-side energy.

Senator Hill agreed with those four plus nuclear energy as a possible category. He thought perhaps working groups could be formed to discuss each of these components. **Representative Anderson** said that nuclear has to be discussed and suggested that could be put under the generation component.

Representative Eskridge said that ethanol interests and the Farm Bureau have made a commitment to meet this summer, outside of this committee, to try to come up with a way to promote the use of ethanol in Idaho in a way the legislature could support.

Representative Stevenson agreed that the committee needs smaller groups that can meet and involve outside interests to discuss these components and bring back their findings to the larger committee.

Senator Hill suggested that the committee wait to break into smaller committees until a consultant is decided upon. **Senator McKenzie** agreed and suggested that the committee look at developing a broad policy plan that is flexible that looks out ten to fifteen years and at the same time, the subcommittees could be considering recommendations as to implementation of that plan that are more specific.

Senator Kelly asked if the consultant is to be used to guide the process and the subcommittees meet at the same time, how will that work. **Representative Eskridge** said in his opinion the subcommittees would work to develop concepts on how to proceed with development of the process and the consultant would be used to develop the final plan. **Senator Hill** said that direction would come from this committee but agreed with **Representative Eskridge's** comments.

Senator Kelly asked if it is intended that fuel is to be included in an energy plan beyond electricity generation. **Representative Eskridge** said yes that intended to be in this new plan.

Representative Eskridge stated that at the next meeting, they would like to have each of the private utilities discuss in-depth their integrated resource plans and how those are decided upon.

Senator Werk suggested a review of the processes other states have gone through in developing an energy plan be done at the next meeting.

Representative Smith asked whether the Farm Bureau would be ready to give a presentation on their progress with ethanol at the next meeting. **Mr. Russ Hendricks, Farm Bureau,** said he would give the committee an update of where they were in the process. Their first meeting is being held on May 10 and he said he would report back to this committee.

Senator Kelly asked for more information regarding transmission capacity and regulation as well as pipeline information.

In response to a question from **Representative Bell and Senator Gannon, Representative Eskridge** suggested that committee members give names of people that could be used as resources for the smaller subcommittees to **Mr. Nugent** in the Legislative Services Office.

In response to a question from **Representative Block, Senator Hill** reviewed the process for selecting the consultant. He explained that as the proposals are received, the cochairmen will review them and come back to the committee for final approval. He said the cochairmen will probably hold the interviews with the final candidates, but that any committee member is welcome to sit in and ask questions.

Representative Eskridge distributed a handout announcing a coal gasification council workshop being held in North Dakota.

The meeting was adjourned at 12:45 p.m.