Boardman to Hemingway Transmission Line Project

Purpose and Need Meeting Summary
Central Advisory Area
July 8, 2009

Best Western Sunridge Inn
1 Sunridge Lane
Baker City, OR 97814

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INTRODUCTION

Idaho Power is committed to partnering with communities to identify proposed and alternate routes for the Boardman to Hemingway Transmission Line Project. Following public scoping meetings held in October 2008, Idaho Power initiated a process to engage communities—from Boardman, Oregon, to Melba, Idaho—in siting the proposed transmission line. This process is called the Community Advisory Process (CAP). Idaho Power will conduct a comprehensive and inclusive public process to locate proposed and alternate routes for the Boardman to Hemingway Transmission Line Project.

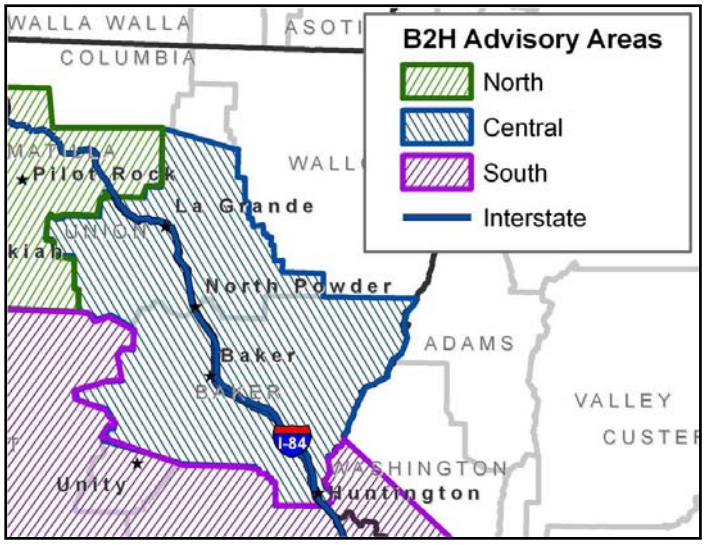
As a part of the Community Advisory Process, a Project Advisory Team (PAT) has been formed in each of the three geographic project areas: North, Central and South. During the first Central Project Advisory Team meeting, team members expressed concern about the purpose and need of the proposed transmission line. To address this concern Idaho Power hosted an informal meeting. The purpose of this meeting was to:

- Present information about the background, purpose and need of the Boardman to Hemingway Transmission Line Project.
- Answer questions and discuss concerns with Project Advisory Team members.

Presenters:

- Dave Angell – Idaho Power, Manager of Delivery Planning
- Mark Stokes – Idaho Power, Manager of Power Supply Planning

This document summarizes the Central Purpose and Need meeting held in Baker City, Oregon, on July 8, 2009, from 4 to 6 PM. This summary is not intended to be a stand-alone source of information about the purpose and need for the project. The information discussed in this meeting that is outlined in this summary was very technical and in-depth. For more information please contact Kent McCarthy at Idaho Power, kmccarthy@idahopower.com, (208) 388-6525.



WELCOME AND BACKGROUND

Kent McCarthy, Idaho Power Community Advisory Process Project Leader, welcomed participants, asked everyone to introduce themselves, and introduced the day's speakers. An agenda and sign-in sheet are included in Appendix 1.

Dave Angell, Manager of Delivery Planning at Idaho Power, provided necessary background information about the following topics:

- Energy
  - Defined as the wattage moved over time
  - Metered as a kilowatt hour (kWh) for individual homes and a megawatt hour (MWh) for the service area
- Demand
  - How much energy is needed
  - Also called load
- Capacity
  - Measured instantaneously as a watt
  - 1,000 watts = 1 kilowatt (kW)
  - 1,000,000 watts = 1 megawatt (MW)
- Electrical Flow
  - Electricity flows from a higher to lower potential but can only travel one direction at a time on a set of transmission lines.
  - Energy is bought and sold through a sharing agreement between utilities in the Western Electricity Coordinating Council.

Angell displayed a graph of energy use over time for the Baker City area (provided by the Oregon Trail Electrical Company). When comparing use and demand (peak instantaneous usage) in 1997 and 2008, use has increased. This profile matches Idaho Power customers even though the Treasure Valley has seen a population increase. Increased energy use in the Baker City area is probably due to increased irrigation.

PENDING LEGISLATION

Mark Stokes, Manager of Power Supply Planning at Idaho Power, distributed a summary of active federal renewable electricity legislation (Appendix 2). The bill (HR 2454) contains both carbon caps and renewable energy requirements. Idaho Power has shares in coal generation facilities and predicts coal generation will need to be reduced. However, changes to HR 2454 are expected in the Senate since many senators are from states that rely heavily on coal generation. The bill also requires a certain percentage of energy to be from renewable resources—from approximately 3 percent in 2012 to 20 percent in 2020.

Although existing hydropower generation can be subtracted from the sales base used to calculate the percentage of renewable resources required, Idaho Power would still need an increasing amount of renewable resources in their portfolio.

Discussion

Based on questions from meeting attendees, Idaho Power provided the following information:

- Stokes could not predict how HR 2454 will affect rates since it has not been finalized. The actual impact on utilities will depend on the carbon allowance allocation methodology. However, if carbon caps are included in the final bill, utilities relying heavily on coal could be significantly affected.
- Idaho Power has not predicted how customers may reduce usage in response to higher costs.
- For the 2009 IRP, all of Idaho Power's future portfolio options are geared towards meeting the proposed federal renewable energy standard (RES).

PURPOSE OF THE LINE

Idaho Power discussed the following issues regarding the specific purpose of the Boardman to Hemingway (B2H) transmission line:

- The purpose of the B2H line is to connect to the Mid-Columbia (Mid-C) hub—a trading hub within central Washington—to buy energy and transmit it to Idaho.
- The Bonneville Power Administration (BPA) controls transmission from the entire Mid-C area.
- Generation sources in this area include natural gas, wind, hydropower, and nuclear.
- The B2H line is not being built to transmit energy from the Boardman Coal Plant.
- The Gateway West line has a 2014 in-service date; the B2H line has a 2015 date.
- Angell displayed a map of projected load growth, new generation resources, and planned transmission lines in the western region.
- California has an aggressive renewable energy portfolio requirement, and many merchant transmission lines have been proposed to move wind energy out of Wyoming and Montana into California.
- The Gateway West line will move energy from Wyoming to the Pacific Northwest.
- Idaho Power's proposed transmission lines are not eligible for stimulus funding at this time. Stimulus funding enabled the BPA to increase bonding authority, but the BPA is a different entity than Idaho Power.

NORTHERN TIER TRANSMISSION GROUP

In 1992, an energy policy act geared toward deregulating the energy industry was introduced. Pacific Northwest utilities have been working towards deregulation for several years but have been unable to reach an agreement because rates are different (cost shifting). Therefore, regional planning became the best alternative and the Northern Tier Transmission Group (NTTG) was assembled. The NTTG is a group of transmission providers and customers actively involved in the sale and purchase of transmission capacity from the power grid that delivers electricity to customers in the Northwest and mountain states. The NTTG examined load growth expected in the region, generation in the generation queue, and transmission lines needed to move that energy.

Discussion

Based on questions from meeting attendees, Idaho Power provided the following information:

- The NTTG developed the proposed transmission lines by matching loads and needs identified in existing studies from the mid-1990s. These lines are all planned; none are on the ground.
- The NTTG plans energy transmission on a regional scale.
- The Federal Energy Regulatory Commission determines transmission rates.

ENERGY LOSSES

The net import capacity for the B2H line would be 850 MW; the export capacity would exceed 1,400 MW if the Gateway West line is also built. When energy flows on a transmission line, some is lost as heat. To illustrate losses on a 500 kV, 300 mile transmission line, Angell displayed an excel spreadsheet of peak demand on July 16, 2005. By 3 PM, Idaho Power was importing power and using 91 percent capacity of the existing transmission line. When nearly 1,200 MWh were flowing in, losses equaled 2.67 percent.

ALTERNATING AND DIRECT CURRENT

On a direct current (DC) line, electrons move steadily in one direction. On an alternating current (AC) line, the transmission line itself acts like a large inductor, which creates a magnetic flux. DC lines do not act like an inductor so the current can be pushed easily through the line. However, for the length of line Idaho Power is proposing, AC wires are less expensive and if the same current and resistance are on the lines, energy losses will be the same. DC lines need converters to convert AC current to DC current for traveling along the DC wires. These convertors are expensive to build and operate and result in additional energy losses. DC lines are economical if building a very long line that transports energy from one place to another without adding or removing energy along the line.

Discussion

Based on questions from meeting attendees, Idaho Power provided the following information:

- Line sag is due to current and resistance, which would be the same for DC and AC lines.
- DC towers are shorter than AC towers but the lines are not further from the ground.
- Angell offered to provide additional information regarding DC current to participants if requested.

INTEGRATED RESOURCE PLAN

Stokes updated participants on the Integrated Resource Plan (IRP) (Appendix 3). The Idaho Public Utilities Commission (IPUC) and Oregon Public Utilities Commission require utilities to each file an IRP, which has four goals:

1. Identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period.

2. Give equal and balanced treatment to both supply- and demand-side resources.

3. Ensure the portfolio of selected resources balances cost, risk, and environmental concerns.

4. Involve the public in the planning process in a meaningful way.

Idaho Power has met the last goal by forming the Integrated Resource Plan Advisory Council, which represents a broad range of customer, governmental, environmental, and regulatory interests and meets monthly while preparing the IRP.

Cost Comparisons

Transmission Line Options

In 2004, the IPUC recommended Idaho Power expand its analysis of possible transmission projects, associated costs, and potential risks in the 2006 IRP. Stokes displayed the 30-year nominal levelized cost of production estimates for 14 different transmission line options. The estimates were based on the following:

- Baseload capacity factors—61%
- Peaking capacity factors—4%
- Capital costs
- Fixed operating costs

Levelized costs are useful tools since certain resource alternatives carry low fixed costs and high operating costs, while other alternatives require significantly higher capital investment and subsequent fixed operating costs but have very low variable operating costs. The levelized cost of production measurement represents the estimated cost per MWh for a resource based on some expected level of energy output, over the lifetime of the resource.

As shown in Table 1 below, the B2H line fell in the middle of the cost range for this analysis.

Table 1. Comparing 30-year nominal levelized cost for transmission lines considered in the IRP

	Least Expensive Line ($/MWh)	Most Expensive Line ($/MWh)	B2H Line ($/MWh)
Baseload	65	82	72
Peaking Service	130	410	275

Supply-Side Resource Options

The 2006 IRP compared the 30-year levelized costs between two supply-side resource alternatives—a new combined-cycle combustion turbine (CCCT) and a new single-cycle combustion turbine (SCCT)—with the new B2H line. SCCTs are constructed to meet peak loads and have lower capital costs than CCCTs.

The B2H line capital costs (per kW) are much lower than the capital costs for a new CCCT; however, the 30-year levelized costs (per MWh) are nearly identical. Although the levelized costs are similar, another CCCT would put Idaho Power at greater risk if natural gas prices, which have historically been very volatile, increase. To minimize risk, Idaho Power tries to maintain a diversified generation portfolio to avoid overdependence on one particular resource.

When using capacity factor to compare levelized costs between the B2H line, a new CCCT, and a new SCCT, the percentage of time a resource is used greatly affects its levelized cost (Table 2). The import capacity of the B2H line used in this analysis is 850 MW. Idaho Power estimates the initial capacity factor of the B2H line will be 26% in 2015 and will increase over time as customer demand continues to grow.

Table 2. Levelized cost comparison between the B2H line, a new CCCT, and a new SCCT

Capacity Factor (%)	B2H Line ($/MWh)	CCCT ($/MWh)	SCCT ($/MWh)
6	250	400	250
26	150	170	170
65	125	125	125

Idaho Power recently updated their load forecast to reflect downsizing of large commercial users, but actual load was within 29 MW of the forecasted load. A new forecast will be complete in August 2009 for the latest IRP.

Discussion

Based on questions from meeting attendees, Idaho Power provided the following information:

- Oregon and Washington have more stringent energy efficiency building requirements than Idaho.
- Idaho Power incorporates a variety of generation resources to protect against severe movements in their power supply costs. Should market or policy conditions change dramatically, Idaho Power customers will have the protection of a diverse resource portfolio.

- Examples of risk include natural gas price volatility, the amount of water available each year, and future regulation of carbon emissions.
- Future generation resources are possible:
  - Nuclear—Five or six plants are on the horizon, but building costs and waste are still issues. Any plant coming online is 15–20 years out. Alternate Energy Holdings is proposing a 1,600 MW nuclear plant in southwestern Idaho and still working with Elmore County on the permitting process.
  - Coal gasification—A process used to convert coal into a synthetic gas product, coal gasification won't be commercially available for at least 10 years.
  - Wind—As an intermittent resource, forecasting wind generation is difficult. More wind farms are being proposed in Wyoming and Montana, so energy will need to be moved around more than in the past. Wind costs approximately $110/MWh.
  - Solar—Although the cost of solar energy has fallen, it is still expensive.
  - Hydropower—Permitting and environmental concerns are the biggest issues for hydropower. It is unlikely that new large hydropower facilities will be built in the United States; however, smaller, run-of-river plants are possible.
  - Emerging storage technologies—Batteries, flywheels, compressed air, and pump storage are getting a lot of attention but are not yet economically feasible.
- Third party requests to use the line would make a 230 kV line very limiting, so Idaho Power increased it to a 500 kV line.
- Energy corridors established by the Bureau of Land Management are on public land, which is not contiguous. Idaho Power tried to stay within the corridors as much as possible.
- The established energy corridors will be available during the mapping sessions.
- The same process for placing transmission lines in energy corridors is required by NEPA.
- A gas unit is most efficient when run at capacity; however, most units are turned off in spring when water is flowing through the hydropower system.
- Energy consumption in Idaho is 14 percent agriculture, 50 percent commercial, and 36 percent residential.

LINE USE

The Hemingway Substation was chosen as the starting point because Idaho Power has another substation in Jerome, Idaho. PacifiCorp also has an existing 500 kV transmission line that runs from Jerome to Summer Lake, Oregon, and the Hemingway substation is along this transmission line route. PacifiCorp is also proposing a new line from Hemingway to Captain Jack (just north of the California border). Idaho Power has several requests from generators to use the proposed line and Idaho Power needs to integrate additional transmission into its system. Even if a nuclear plant is built in Elmore County, Idaho Power would never rely on all 1,600 MW from that plant because the system would be destabilized if that plant ever went offline.

APPENDIX 1—AGENDA AND ATTENDEES

Boardman to Hemingway Project
Purpose and Need Meeting
Wednesday, July 8, 2009 • 4 p.m. to 6 p.m.
Best Western Sunridge Inn
1 Sunridge Lane • Baker City, OR 97814

AGENDA

Meeting objectives:

- Present information about the background, purpose and need of the Boardman to Hemingway Project
- Answer questions and discuss concerns with PAT members

Presenters:	**Dave Angell – Idaho Power, Manager of Delivery Planning**
	Mark Stokes – Idaho Power, Manager of Power Supply Planning

www.boardmantohemingway.com/

P.O. Box 70 (83707)
1221 W. Idaho St.
Boise, ID 83702

Central Purpose and Need Attendees
Wednesday July 8, 2009
4 p.m. – 6 p.m.
Best Western Sunridge Inn
Baker City, OR

1. Eric Hackett
2. Scott Hartell
3. Dorthy Wooters
4. Garth Johnson
5. Dennis Dorrah
6. Dan Weitz
7. John Milbert
8. Lynda DeLore
9. Vicki Wares
10. Kristen Wares
11. Elaine Hagberg
12. Yogi Hagberg
13. Diane Bloomer
14. John Williams
15. Senator Ted Ferrioli
16. Eric Lawrence

Staff:
Eric Hackett – Idaho Power
Dave Angell – Idaho Power
Mark Stokes – Idaho Power
Kent McCarthy – Idaho Power
Kara Veit – RBCI
Amanda Edge – RBCI
Jessica – RBCI
Nicole Pearson – Peak Science

APPENDIX 2—PENDING LEGISLATION

Active Federal Renewable Electricity Standard (RES) Legislation

As of June 8, 2009

Policy Design Element	*H.R. 2454*	*Majority RES Draft Text*
Sponsor	Waxman (D-MA) & Markey (D-MA)	Bingaman (D-NM)
Chamber	House	Senate
Summary	20% by 2020	15% by 2021
Status	In committee (introduced May 2009)	In committee (introduced May 2009)
Treatment of Existing Hydro	Excluded from the sales base used to calculate	Excluded from the sales base used to calculate
Required Annual Percentage	2012 - 6% 2013 - 6% 2014 - 9.5% 2015 - 9.5% 2016 - 13% 2017 - 13% 2018 - 16.5% 2019 - 16.5% 2020 - 20% 2021-2039 - 20%	2011 - 3% 2014 - 6% 2017 - 9% 2019 - 12% 2021 - 15%
Resources Eligible to Meet RES	Wind, solar, geothermal, renewable biomass, biogas and biofuels derived exclusively from renewable biomass, marine and hydrokinetic and qualified hydropower (efficiency improvements or capacity additions).	Wind, solar, geothermal, ocean, biomass, landfill gas, incremental hydropower (efficiency improvements or capacity additions), hydrokinetic and new hydropower at existing dams with no generation.
Qualifying Date for Resources Eligible to Meet RES	Qualified hydropower (placed in service on or after January 1, 1992), no qualifying date for other eligible resources.	Incremental hydropower (placed in service on or after January 1, 2001), other eligible resources (placed in service on or after January 1, 2006).
Shelf life of federal RECs	Unlimited banking of RECs	3 years from date of issuance of the REC.
Alternative Compliance	$25/MWh (inflation adjusted).	$21.10/MWh (inflation adjusted) if the electric utility does not elect to petition the Secretary to waive the requirement.
Non-Compliance Penalty	$50/MWh (inflation adjusted) or twice the Alternative Compliance payment.	200% of the value of the alternative compliance payment (adjusted for inflation)
Use of funds from Alternative Compliance Payments and Penalties	Paid directly to state in which electric supplier is located to be used for deploying renewable technologies and cost-effective energy efficiency measures and programs.	State grants for development of renewable resources or to offset increases in customers bills.
Energy Efficiency	Utilities can meet up to 25% of their requirements through energy efficiency savings: customer facility savings, reductions in distribution system losses, combined heat and power (CHP) savings and fuel cell savings. Governor can petition FERC to increase the energy efficiency savings proportion to not more than 40%.	Utilities can meet up to 26.67% of their requirements through energy efficiency savings: customer facility savings, electricity savings, recycled energy combined heat and power (CHP).
Cost Recovery	Not Addressed	Not Addressed
Exemption from RES	Electric utilities with less than 4 million MWh of retail sales.	Electric utilities with less than 4 million MWh of retail sales and the State of Hawaii.
Power Sales Contracts	If not addressed in the contract, RECs belong to the supplier.	Not Addressed
Coordination with State Policies	States can have higher standards.	States can have higher standards.
Renewable Generation Facilities	Not Addressed	Double RECs
Distributed Generation Facility	Triple RECs (generation < 2 MW)	Triple RECs (generation < 1 MW)
Mixed Renewable Resource (ex. combined solar and gas plant)	RECs based upon portion attributable to the renewable energy resource.	Not Addressed
Waiver from Compliance	Not Addressed	Secretary may wave requirements for 5 years because of natural disasters or acts of god.

APPENDIX 3—POWERPOINT PRESENTATION

Integrated Resource Planning (IRP)

In the early 1990s, the Idaho and Oregon public utilities commissions began requiring utilities to file an Integrated Resource Plan (IRP).

IRP Goals:

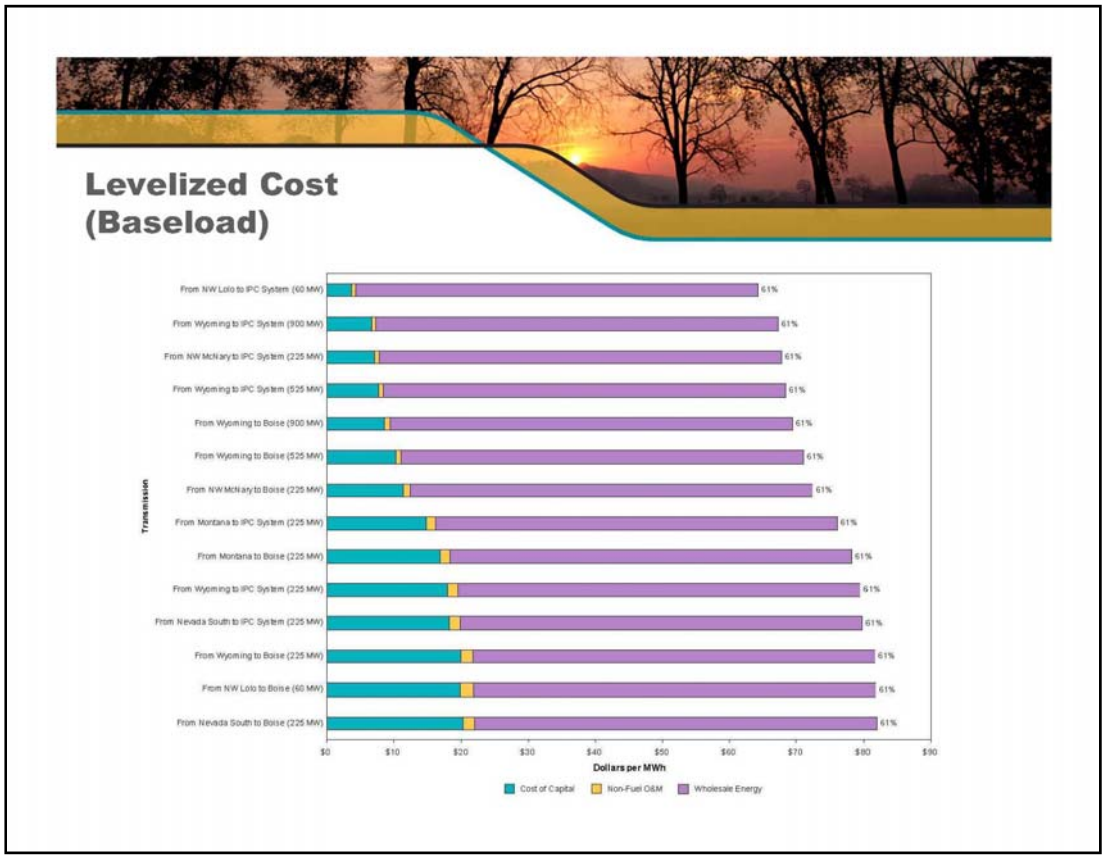
- Identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period
- Give equal and balanced treatment to both supply-side resources and demand-side measures
- Ensure the portfolio of selected resources balances cost, risk, and environmental concerns
- Involve the public in the planning process in a meaningful way

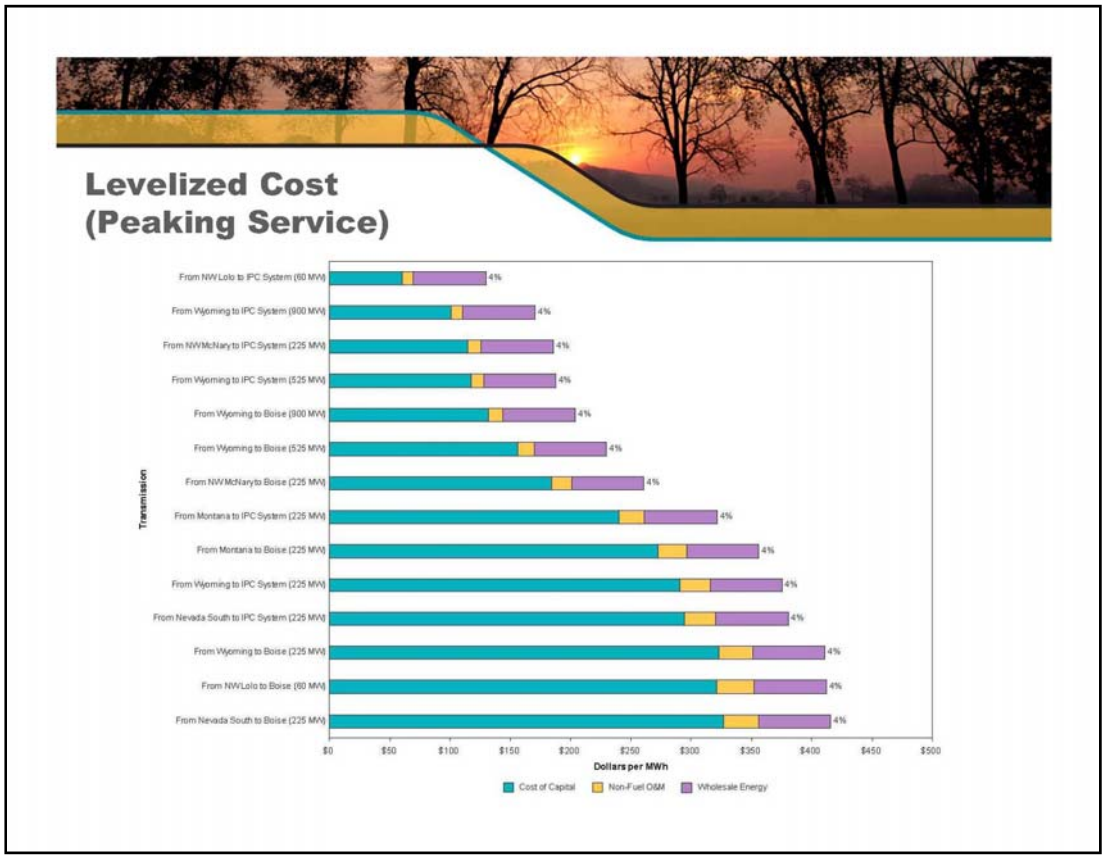
IRP Advisory Council Offers Opportunity for Public Input

- Beginning with the 2004 IRP, Idaho Power formed the Integrated Resource Plan Advisory Council (IRPAC) to increase public participation in the planning process
- IRP Advisory Council members represent a broad range of customer, governmental, environmental and regulatory interests
- The IRP Advisory Council meets monthly during the preparation of the IRP

B2H History in IRP

- In its acceptance of Idaho Power's 2004 IRP, the Idaho PUC asked Idaho Power to evaluate additional transmission options in the 2006 IRP
- Transmission options analyzed in the 2006 IRP included:
  - McNary to Boise
  - Lolo to Oxbow
  - Wyoming to Boise
  - Montana to Boise
  - Nevada to Boise

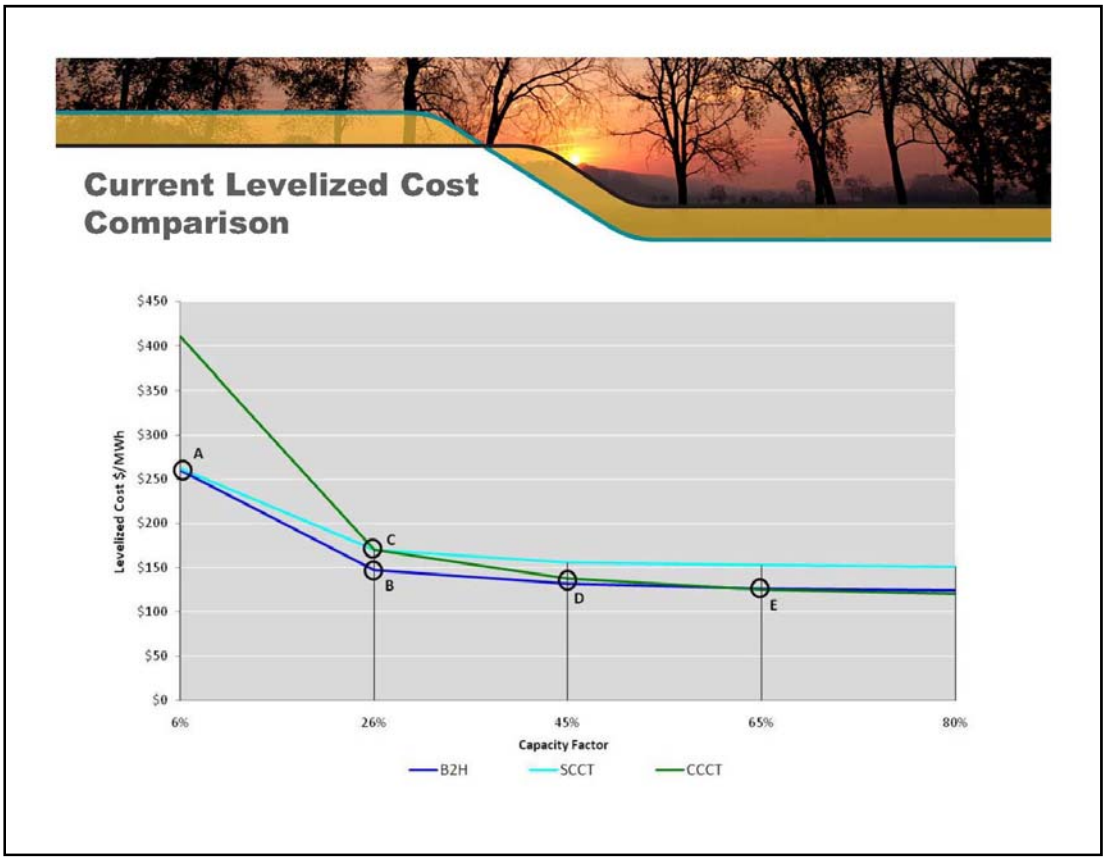

Levelized Cost
(Baseload)
From NW Lolo to IPC System (60 MW)
From Wyoming to IPC System (300 MW)
From NW McNary to IPC System (225 MW)
From Wyoming to IPC System (525 MW)
From Wyoming to Boise (300 MW)
From Wyoming to Boise (525 MW)
From NW McNary to Boise (225 MW)
From Montana to IPC System (225 MW)
From Montana to Boise (225 MW)
From Wyoming to IPC System (225 MW)
From Nevada South to IPC System (225 MW)
From Wyoming to Boise (225 MW)
From NW Lolo to Boise (60 MW)
From Nevada South to Boise (225 MW)
61%
Transmission
$0
$10
$20
$30
$40
$50
$60
$70
$80
$90
Dollars per MWh
Cost of Capital
Non-Fuel O&M
Wholesale Energy

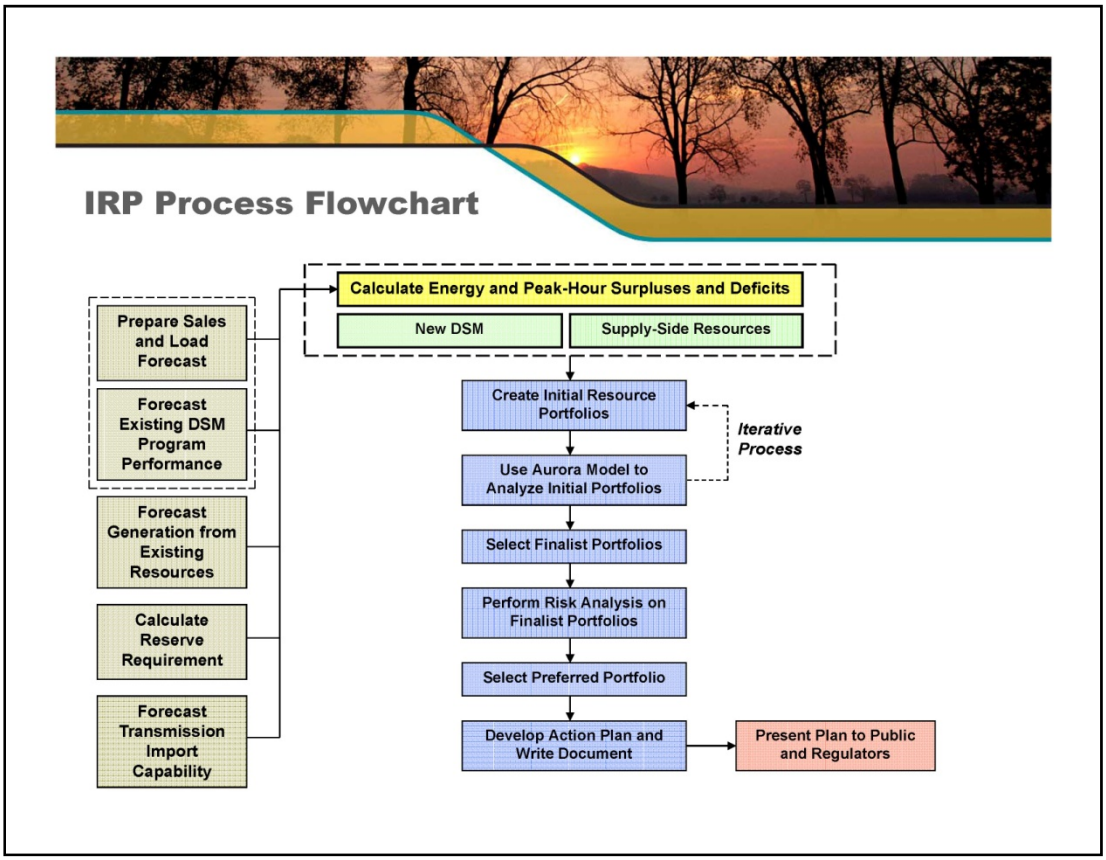

Levelized Cost
(Peaking Service)
Transmission
From NW Lolo to IPC System (60 MW)
From Wyoming to IPC System (900 MW)
From NW McNary to IPC System (225 MW)
From Wyoming to IPC System (525 MW)
From Wyoming to Boise (900 MW)
From Wyoming to Boise (525 MW)
From NW McNary to Boise (225 MW)
From Montana to IPC System (225 MW)
From Montana to Boise (225 MW)
From Wyoming to IPC System (225 MW)
From Nevada South to IPC System (225 MW)
From Wyoming to Boise (225 MW)
From NW Lolo to Boise (60 MW)
From Nevada South to Boise (225 MW)
4%
$0
$50
$100
$150
$200
$250
$300
$350
$400
$450
$500
Dollars per MWh
Cost of Capital
Non-Fuel O&M
Wholesale Energy

IRP Cost Comparisons

Capital Cost ($/kW)	2006 IRP	2009 IRP
CCCT	$693	$1,293
B2H	$546	$706

30-Year Levelized Cost ($/MWh)	2006 IRP	2009 IRP
CCCT	$78	$125
B2H	$72	$125


Current Levelized Cost Comparison
$450
$400
$350
$300
$250
$200
$150
$100
$50
$0
Levelized Cost $/MWh
A
B
C
D
E
6%
26%
45%
65%
80%
Capacity Factor
B2H
SCCT
CCCT


IRP Process Flowchart
Prepare Sales and Load Forecast
Forecast Existing DSM Program Performance
Forecast Generation from Existing Resources
Calculate Reserve Requirement
Forecast Transmission Import Capability
Calculate Energy and Peak-Hour Surpluses and Deficits
New DSM
Supply-Side Resources
Create Initial Resource Portfolios
Iterative Process
Use Aurora Model to Analyze Initial Portfolios
Select Finalist Portfolios
Perform Risk Analysis on Finalist Portfolios
Select Preferred Portfolio
Develop Action Plan and Write Document
Present Plan to Public and Regulators

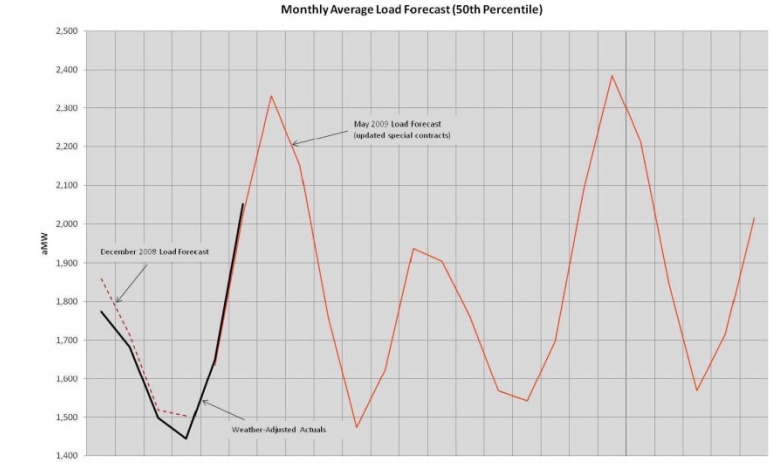
Average Energy Load and Resource Balance

Average Energy	2015											
Load and Resource Balance	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**
Load Forecast (70th%) - May 2009	(2,239)	(2,068)	(1,824)	(1,810)	(2,002)	(2,435)	(2,763)	(2,546)	(2,101)	(1,791)	(1,965)	(2,307)
Existing DSM	67	67	68	70	78	95	96	93	74	68	68	67
Net Load Forecast (70th%) w/DSM	(2,171)	(2,001)	(1,756)	(1,740)	(1,925)	(2,340)	(2,668)	(2,453)	(2,027)	(1,723)	(1,897)	(2,239)
Existing Resources												
Coal	938	938	868	777	728	933	938	938	938	937	938	938
Hydro (70th%) - HCC	654	537	598	694	837	660	460	358	409	395	364	474
Hydro (70th%) - Other	214	300	252	240	327	338	246	242	233	216	202	206
Shoshone Falls Upgrade	6	31	14	1	19	22	0	0	0	0	0	3
Total Hydro (70th%)	874	869	864	935	1,183	1,020	706	599	642	611	567	683
CSPP (including wind)	101	120	130	148	185	195	181	174	172	146	120	125
Power Purchase Agreements												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana - Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	44	43	44	45	40	47	47	43	39	45	42	54
Firm Pacific NW Import Capability (Actuals Through Sept 2010)	202	379	446	290	335	222	103	172	167	214	354	297
Langley Gulch	251	251	251	251	251	251	251	251	251	251	251	251
Boardman to Hemingway	0	0	0	0	0	225	225	225	225	225	225	225
Gas Peakers	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	**2,411**	**2,501**	**2,503**	**2,445**	**2,721**	**2,893**	**2,452**	**2,403**	**2,434**	**2,429**	**2,497**	**2,573**
Monthly Surplus/Deficit	**239**	**500**	**847**	**706**	**796**	**554**	**(216)**	**(50)**	**407**	**706**	**600**	**334**
2009 IRP DSM												
Industrial	4	4	4	4	4	4	4	4	4	4	4	4
Comercial	1	1	1	1	1	1	1	1	1	1	1	1
Residential	2	2	2	2	2	6	6	6	2	2	2	2
Total New DSM Average Energy	13	13	13	13	13	12	12	12	13	13	13	13
Monthly Surplus/Deficit w/New DSM	**252**	**513**	**860**	**719**	**809**	**565**	**(204)**	**(38)**	**420**	**719**	**613**	**346**

Peak-Hour Load and Resource Balance

Peak-Hour	2015											
Load and Resource Balance	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Load Forecast (95th%) - May 2009	(2,895)	(2,715)	(2,436)	(2,166)	(3,123)	(3,755)	(3,962)	(3,563)	(3,296)	(2,395)	(2,638)	(3,113)
Existing DSM	67	67	68	70	78	172	175	163	74	68	68	67
Peak-Hour Load Forecast	(2,827)	(2,647)	(2,368)	(2,096)	(3,045)	(3,583)	(3,787)	(3,400)	(3,222)	(2,266)	(2,559)	(3,046)
Existing Resources												
Coal	982	982	816	816	761	982	982	982	982	982	982	982
Hydro (90th%) - HCC	1,079	847	555	680	1,198	1,115	1,035	945	1,035	765	600	786
Hydro (90th%) - Other	197	199	190	209	295	307	241	230	207	202	191	196
Shoshone Falls Upgrade	2	2	0	0	14	17	0	0	0	0	0	1
Total Hydro	1,278	1,048	745	893	1,508	1,440	1,276	1,175	1,242	968	791	982
CSPP (including wind)	49	50	55	81	127	137	141	136	119	87	62	57
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana - Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability (Actuals Through Sept 2010)	202	378	446	280	335	222	103	172	167	214	354	297
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300
Boardman to Hemingway	0	0	0	0	0	225	225	225	225	225	225	225
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	3,242	3,190	2,793	2,811	3,462	3,737	3,458	3,421	3,466	3,207	3,145	3,274
Monthly Surplus/Deficit	0	0	0	0	0	0	(329)	0	0	0	0	0
2009 IRP DSM												
AC Cool Credit						5	5	5				
Commercial (ENERNOC)						57	57	57				
Irrigation Peak Rewards						228	226	(24)				
Energy Efficiency Peak Reduction						12	12	12				
Total New DSM Peak Reduction	0	0	0	0	0	302	300	49	0	0	0	0
Monthly Surplus/Deficit w/ New DSM	0	0	0	0	0	0	(30)	0	0	0	0	0

Load Forecast Performance



	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Load Forecast (Dec 2008)	1,859	1,714	1,519	1,504																				
Load Forecast (May 2009)					1,635	2,022	2,332	2,150	1,760	1,473	1,623	1,937	1,905	1,762	1,569	1,543	1,698	2,088	2,385	2,214	1,848	1,569	1,716	2,016
Weather-Adjusted Actuals	1,774	1,683	1,499	1,445	1,650	2,051																		
Variance	(86)	(31)	(20)	(59)	15	29	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0