Southeast Idaho Load Service (SILS) Comment Period

Supporting Documentation

August 6, 2012

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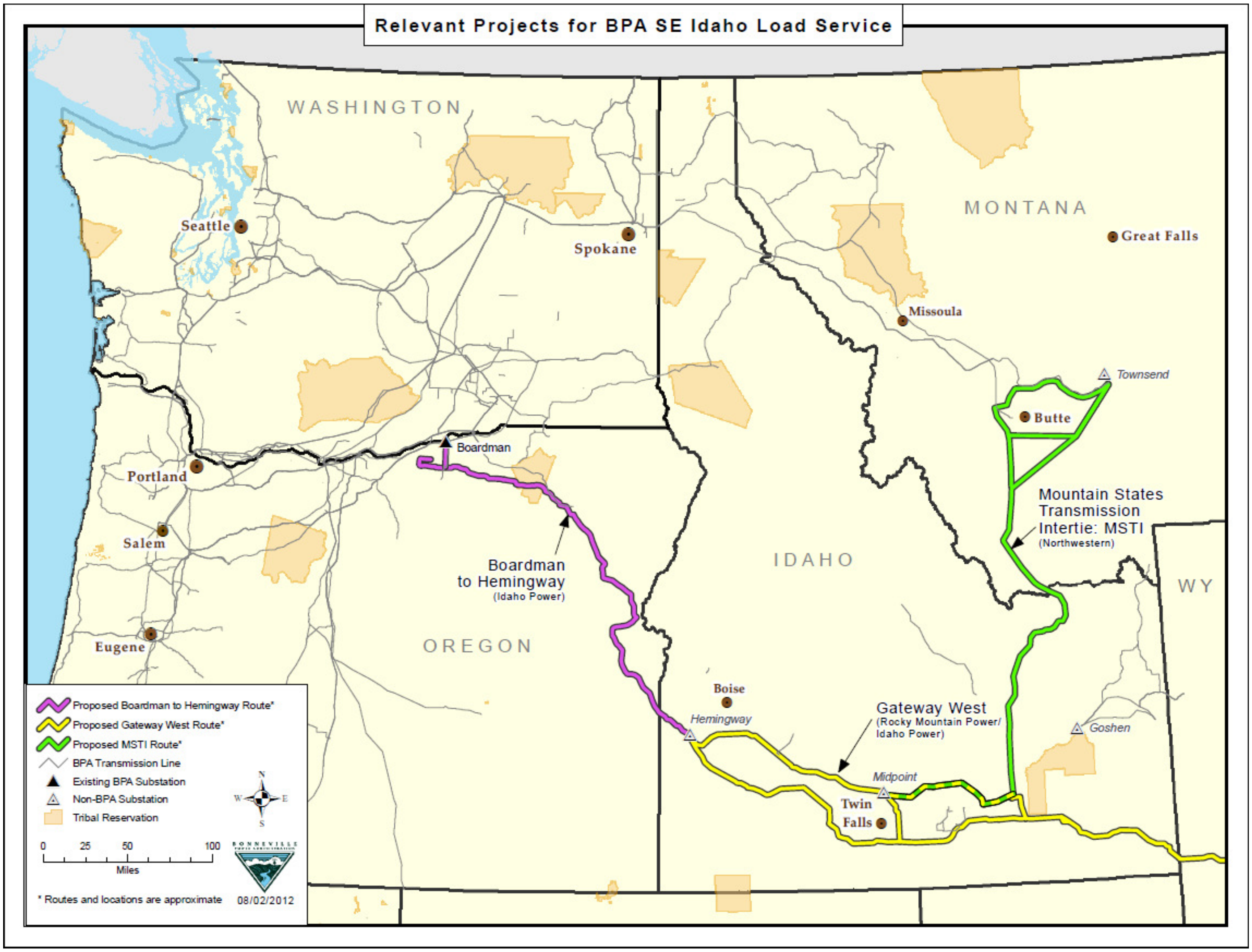
1. Map of Region with Contemplated Transmission Projects



2. Background

Current Service

The Bonneville Power Administration (BPA) currently serves six preference customers located in southeastern Idaho under long term Regional Dialogue contracts and network transmission (NT) service agreements. These customers are:

City of Idaho Falls, doing business as Idaho Falls Power (Idaho Falls)
City of Soda Springs (Soda Springs)
Fall River Electric Cooperative, Incorporated[1] (Fall River)
Lost River Rural Electric Cooperative, Incorporated (Lost River)
Lower Valley Electric Cooperative, Incorporated (Lower Valley)
Salmon River Electric Cooperative, Incorporated (Salmon River)

Collectively these customers are referred to as the SE Idaho Customers. The loads of the SE Idaho Customers are referred to as the SE Idaho Load.

The long term power sales contracts held by the SE Idaho Customers, commonly referred to as Regional Dialogue contracts, commit BPA to make power available at Points of Delivery (PODs) in SE Idaho and extend through September 2028. The NT agreements extend through 2031.

Currently BPA provides power to the SE Idaho Customers using two agreements with PacifiCorp. The first, the South Idaho Exchange (SIE), allows BPA to deliver power to PacifiCorp's loads in Oregon, and simultaneously receive an equal amount of power at Goshen substation in SE Idaho. About 50% of the SE Idaho Load is served directly out of Goshen substation, including Lower Valley's entire load and the majority of Fall River's load. For the remaining 50% of the load BPA uses a second agreement with PacifiCorp, a General Transfer Agreement (GTA), to transfer energy from Goshen substation to customer PODs interconnected with PacifiCorp transmission facilities.

These agreements combine to provide very cost effective service to the SE Idaho Customers, with payments under the SIE costing about $9m per year and under the GTA another $2.25m per year.

In June of 2011 PacifiCorp notified BPA that it intended to terminate the GTA, thereby terminating the SIE, effective in June of 2016.

[1] Fall River is a member of the Pacific Northwest Generating Cooperative (PNGC). As with all members of PNGC, PNGC holds agreements with BPA for the acquisition of power and transmission for service to its member, Fall River. Throughout this document the term SE Idaho Customers is intended to include Fall River through BPA's contractual relationships with PNGC.

3. Loads and Existing Resources

Several tables and graphs displaying information on SE Idaho Loads and existing resources in SE Idaho may be found in Appendix A. That information is summarized here for convenience.

Summary of load characteristics:

- Period examined through term of existing power sales contracts, September 2028
- Winter peaking load
- Coincidental peak for period is forecast to be 538 MW in December of 2027
- Peak growth forecasted at rate of 1-1.9% month over month, with more rapid growth expected in summer, and more moderate growth expected in winter
- Energy forecast is largest in December of 2027, when average loads are expected to be 386 aMW
- Energy growth forecasted at rate of 1.2-2% month over month, with more rapid growth expected in late spring and summer, and more moderate growth expected in winter

Existing Resources:

BPA currently markets the output from two hydroelectric projects in SE Idaho. The first, Palisades Dam, is a US Bureau of Reclamation (BOR) project with a nameplate capacity of 176 MW. The second, the Bulb Turbine Project, is a set of three bulb turbine generating plants located on the Snake River and owned by the Idaho Falls Power, which have a combined nameplate capacity of 27 MW[2]. These projects have a combined nameplate capacity of 203 MW.

The BOR is currently refurbishing the 4 turbines at Palisades and the associated efficiency improvements are expected to increase annual generation from Palisades by about 33,000 MWh.

Net Requirements:

On a power planning basis, BPA's expected peak power loads are decremented by available federal generation under a critical water scenario. The result is the net peak power obligation for SE Idaho Loads.

BPA's average obligation for loads in SE Idaho is determined by decrementing the SE Idaho Loads average energy by available generation under an average water scenario.

[2] BPA acquires output of Bulb Turbines under power purchase agreement with Idaho Falls. This analysis assumes that arrangement continues through FY 2028.

4. General Description of Possible Service Arrangements & NEPA

The SILS project team has identified a range of possible service arrangements to meet the agency's obligations to the SE Idaho Customers. This range includes the following broad categories:

1. Construction of Transmission Facilities by BPA
2. BPA's Participation in the Construction of Transmission Facilities by Third Parties
3. Power Purchases and/or Exchanges
4. Open Access Transmission Tariff (OATT) Service

Because BPA does not own transmission facilities that connect the BPA integrated and interconnected federal power system to the SE Idaho Customers, construction or participation in construction of a transmission line from the main network to those customers would be considered a major transmission facility under the Federal Columbia River Transmission System Act, section 4.[3] As such, BPA must obtain Congressional approval to build or participate in building a line. At the time this document was written, both the US House and Senate appropriations committees have approved energy and water appropriations bill language approving BPA building or participating in building a line, which was approved by the full House and is yet to be considered by the Senate.[4]

This document will summarize the options being considered. Certain elements of the above four categories have been combined to enable delivery of power to customer PODs. The service arrangements discussed will be as follows:

1. Power Purchases with OATT Service
2. B2H with OATT Service
3. B2H with Transmission Asset Swaps
4. Mountain States Transmission Intertie (MSTI) with Tap to Goshen Substation
5. Two BPA Construction Scenarios from Montana to SE Idaho

National Environmental Policy Act:

As a federal agency, BPA has responsibilities under the National Environmental Policy Act (NEPA) and other applicable environmental laws (e.g., National Historic Preservation Act, Endangered Species Act) to consider the potential environmental impacts of its actions and to insure that information is available to the decision maker and the public before a decision is made and before the action is taken. BPA will conduct NEPA review as appropriate for decisions regarding service to SE Idaho Loads.

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[3] 16 U.S.C. § 838b.
[4] *See* http://thomas.loc.gov/home/approp/app13.html.

Assumptions and Estimates Included in Analysis:

Throughout this document, BPA makes a variety of assumptions in order to illustrate possible costs associated with each of the identified options. To varying extents most assumptions regarding projects with counterparties have been discussed those potential counterparties. However, unless noted otherwise, no assumption made in this document should be interpreted as a guaranteed characteristic of the described option. Once BPA selects one or more options to pursue for service to SE Idaho Loads, BPA will attempt to transition from assumptions into firm commitments.

BPA has included in this document cost estimates of each identified service arrangement. While these estimates represent BPA's current assessment of cost for each service arrangement, all estimates are heavily assumption-based and may change significantly.

5. Power Purchases & PacifiCorp OATT Service

Role of PacifiCorp OATT Service in Several Options:

Network Integration Transmission Service (OATT Service) from PacifiCorp will play a role in nearly every service arrangement being examined for service to the SE Idaho Loads. This is due to the geographically diverse loads of the SE Idaho Customers. Even in a scenario where BPA constructs transmission facilities from the existing FCRTS to or near Goshen substation in southeast Idaho (as would be the case with MSTI participation), BPA would still require service over PacifiCorp transmission facilities to serve the load not directly interconnected to the BPA facilities behind Goshen substation.

In several of the options discussed in this document, BPA is assumed to minimize OATT Service from PacifiCorp by serving two large pockets of SE Idaho Load using federally owned transmission facilities. The first pocket is behind Goshen substation, which accounts for about 50% of the SE Idaho Load. This load may be served by either MSTI or one of the BPA constructions. BPA is also assumed to further mitigate reliance on PacifiCorp facilities through the construction of a relatively short segment of line between Goshen substation and Sugar Mill substation, which serves Idaho Falls.[5] The load of Idaho Falls accounts for about 25% of all SE Idaho Load. This approach would have the entire loads of Lost River, Salmon River and Soda Springs continue to take service over PacifiCorp transmission facilities, as well as a small portion of Fall River's load. Together, these remaining PacifiCorp served loads would account for about 24% of all SE Idaho Loads.

Power Purchases & OATT Service Arrangement Description:

In the absence of additional transmission facilities, BPA may acquire OATT Service from PacifiCorp to deliver energy to SE Idaho Loads. This energy would be purchased and delivered directly into the eastside of PacifiCorp's system (PACE) as needed. Depending on the location of specific power purchase or purchases, BPA may also need to secure transmission rights from transmission providers adjacent to PACE.

The total cost of this service arrangement would be attributable to the net cost of any purchase power and transmission to PACE if necessary, as well as the cost of OATT Service from PacifiCorp.

This option assumes that any additional network resources required beyond the FCRPS would take the form of purchased power delivered into PACE. Most purchases would reduce BPA's power purchase requirements in the pacific northwest. The net cost of power purchases to serve SE Idaho customers are calculated as the total cost of purchasing power delivered into PACE, less the avoided cost of an equivalent amount of FCRPS power valued at a MIDC price.

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[5] This segment of line is contemplated as a means of avoiding substantial PacifiCorp OATT costs for service to Idaho Falls. BPA would explore the feasibility and economics of this segment as well as other viable approaches in depth before pursuing construction.

While BPA believes that this can be considered to be a reasonable cost estimate of net power purchase cost, there is considerable uncertainty around the future direction, magnitude and volatility of power price differentials between MIDC and PACE power markets. These uncertainties include:

- Fuel price basis differentials between generation in the pacific northwest and Rocky Mountains
- Changes in regional capacity reserve margins across regions over time
- Increases and decreases in transmission congestion between regions
- Regulatory policies that differentially affect resource development and resource retirements between regions, especially coal plant retirements

There is also a risk associated with BPA's future ability to secure firm transmission across PACE to the SE Idaho Loads when needed if BPA were to rely on shorter-term power purchase arrangements. Once the specifics of NT service are identified and any required power purchase arrangement or set of arrangements are identified, BPA will have a better idea of any potential issues with delivery across PACE.

For summary of cost estimates, see Appendix B.

Ancillary Services:

Under this service arrangement, BPA's loads are assumed to remain in the PacifiCorp Balancing Area Authority (BAA) and PacifiCorp is assumed to continue providing ancillary services as they do under the existing agreements and as required by their Tariff. This same assumption is continued for the portions of the SE Idaho Load that requires OATT Service from PacifiCorp.

6. Boardman-to-Hemingway Background

Project Summary:

The Boardman-to-Hemingway Transmission Project (B2H) is a 500 kV transmission line proposed by the Idaho Power Company (Idaho Power) and planned to extend from a new substation near Boardman in northeast Oregon to the Idaho Power/PacifiCorp Hemingway Substation approximately 25 miles southwest of Boise, Idaho. The line is estimated to be 300 miles in length, crossing through Morrow, Umatilla, Union, Baker and Malheur Counties in Oregon, and Owyhee County in Idaho.

Based on a recent filing from Idaho Power, BPA has assumed that the project would be energized and available for use in 2018, making an interim arrangement necessary to serve load between 2016 and 2018. BPA has assumed for cost analysis that a power purchase would be used, with OATT Service, during this interim period.

For complete and up-to-date information on the project, including an updated map of the possible routes for the line, please visit http://www.boardmantohemingway.com/.

BPA's Involvement in B2H:

In July 2011 BPA staff members began meeting with Idaho Power to discuss the feasibility and details of using B2H to assist in service to the SE Idaho Customers. BPA has signed a non-disclosure agreement covering conversations on B2H and related service.

Following extensive discussions, BPA, PacifiCorp and Idaho Power developed and executed an agreement that provided for BPA and PacifiCorp to contribute funding towards the permitting and siting of B2H. In addition, BPA PacifiCorp and Idaho Power executed a Memorandum of Understanding (MOU).[6] This MOU is the basis for BPA, PacifiCorp and Idaho Power to discuss how service between Hemingway Substation in southwest Idaho and the loads of the SE Idaho Customers would be structured. Prior to executing in January of 2012, BPA held a public comment period on both documents.

[6] Both the funding agreement and the MOU may be found on BPA's SILS webpage at: http://transmission.bpa.gov/Customer_Forums/se_idaho/

7. Boardman-to-Hemingway with OATT Service

Description:

This option, as stipulated in the MOU mentioned above, is a service arrangement in which BPA would participate in B2H as a joint owner and rely on PacifiCorp's transmission system from Hemingway Substation to the load PODs in SE Idaho. The cost of this option would include BPA capital costs and the cost OATT Service from PacifiCorp.

In order for PacifiCorp to be able to provide service from Hemingway to the load PODs of the SE Idaho Customers, two things must first occur:

1. PacifiCorp must complete the portion of its Gateway West project that would interconnect Hemingway and Populus Substations
2. PacifiCorp must acquire sufficient capacity from Idaho Power in Idaho Power's Kinport Substation and other transmission assets to accommodate BPA's service to the SE Idaho Customers

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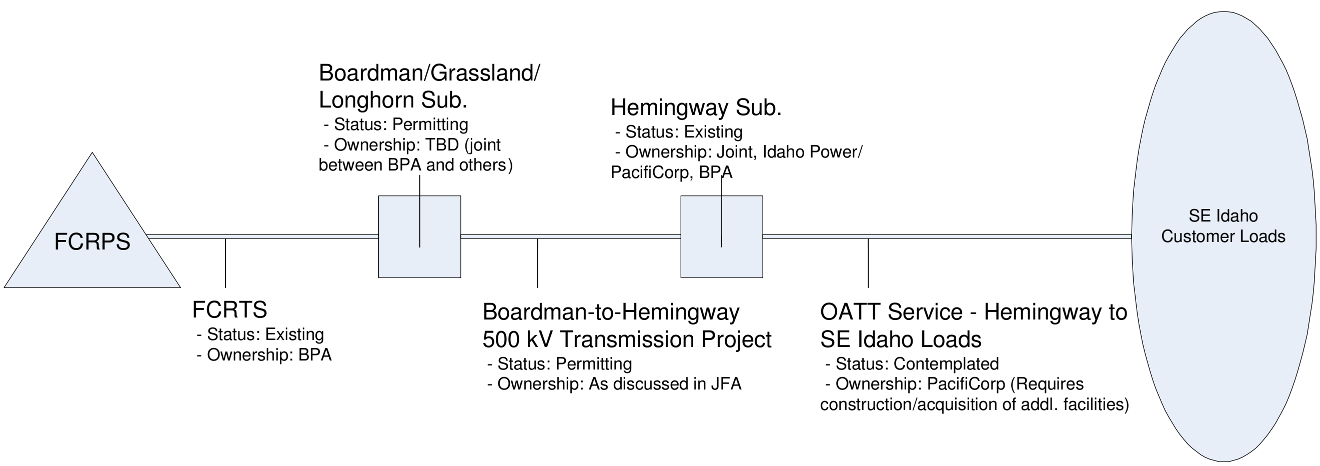

For summary of cost estimates, see Appendix C.

8. Boardman-to-Hemingway with Transmission Asset Swap

Description:

Under this option, BPA would be a participant in B2H as a joint owner and acquire partial ownership in existing transmission facilities currently owned by PacifiCorp and Idaho Power sufficient to give BPA ownership of transmission between the FCRPS and the PODs of the SE Idaho Customers. In return, PacifiCorp and Idaho Power would receive partial ownership in transmission assets currently owned by BPA for the purpose of serving native load. This concept was identified in the previously-mentioned MOU executed by the three parties in January 2012.

The assets that BPA, PacifiCorp and Idaho Power would partially swap, in summary, are:

- BPA would receive assets sufficient to serve the entire loads of the SE Idaho Customers, from Hemingway substation through Midpoint substation, Borah substation, Kinport substation and to Goshen substation.
- BPA would also acquire portions of various facilities between Goshen substation and SE Idaho Customers' PODs on PacifiCorp's system, which are currently served under the GTA.
- PacifiCorp would acquire ownership in BPA assets sufficient to serve a portion of PacifiCorp loads in central Oregon.
- Idaho Power would acquire ownership in BPA assets between the Mid-Columbia market hub (Mid-C) and either Grassland or Longhorn Substation (near Boardman) sufficient to make use of Idaho Power's eastbound capacity on B2H.

No portion of an asset that is currently used to provide service to a third party, or which would be needed to provide service to a third party that has already requested use of those assets (e.g. by submission of a Transmission Service Request to BPA) would be included in the contemplated swap.

Exchange of existing assets to provide partial ownership is an action that has limited historical precedence. An exchange of existing assets will be subject to FERC review/approval.

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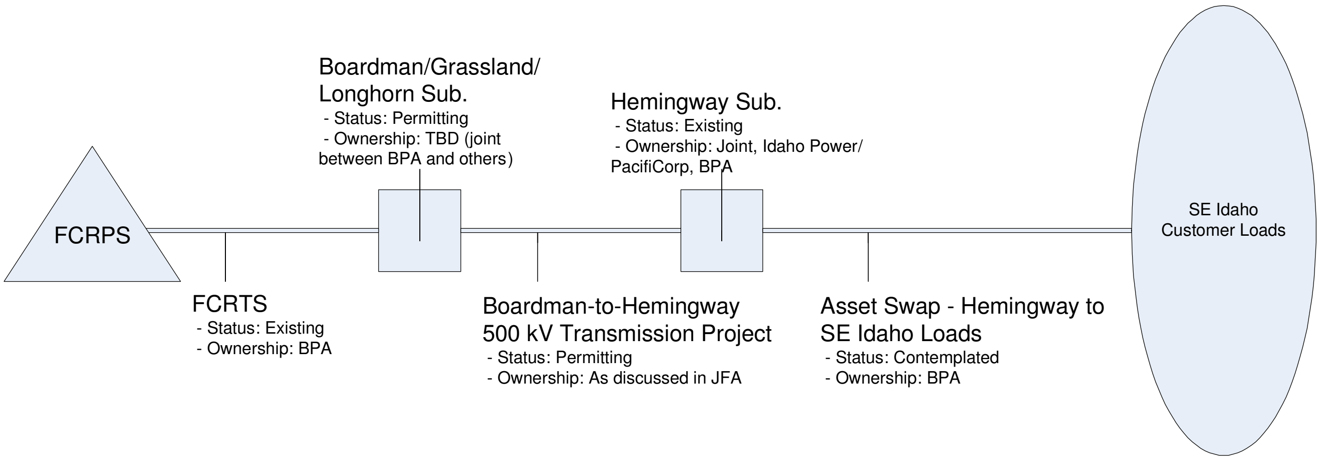

For summary of cost estimates, see Appendix C.

9. Mountain States Transmission Intertie Background

Project Summary:

The Mountain States Transmission Intertie (MSTI) is a 500 kV transmission line proposed by the NorthWestern Energy (NorthWestern) that would extend from a new Townsend Substation in western Montana to Midpoint Substation in south-central Idaho. All of the various routes being examined would have the line sited through the same general region of southeast Idaho in which the loads of the SE Idaho Customers reside. The line is estimated to extend between 400-450 miles. The project is currently in the permitting process, with BLM taking the role of lead federal agency.

For complete and up-to-date information on the project, including an updated map of the possible routes for the line, please visit http://www.msti500kv.com/.

BPA's Involvement in MSTI:

Due to its proximity to the loads in southeast Idaho, BPA identified MSTI as one of the possible options for serving the loads of the SE Idaho Customers. Following the June 2011 termination notice for the GTA and SIE, BPA began meeting with staff at NorthWestern to discuss BPA's interest in the line for service to the SE Idaho Loads.

Since January of 2012, BPA and NorthWestern have been working together under a non-disclosure agreement and MOU between BPA and NorthWestern to examine MSTI, especially as it pertains to load service to the SE Idaho Customers.[7] This includes BPA conducting analysis of the costs associated with the construction and permitting of a tap line between Goshen substation and the MSTI line.

Uncommitted Capacity:

BPA's overall share of MSTI is a significant assumption in this document's characterization of the costs. Should BPA decide to participate in the project in order to serve loads, BPA would need only 550 MW of capacity in the southbound direction. The total capacity of the project is estimated to be 1500 MW southbound and 1100 MW northbound. The WECC Accepted Path Rating for MSTI is 1500 MW north to south and 1100 MW south to north. NorthWestern has received WECC path ratings in both the southbound and northbound direction at these levels. At the present time, none of the capacity that would be provided by the construction of MSTI is committed. Northwestern has not identified a need for MSTI capacity to meet their native load service needs.

In order to estimate cost for this summary, BPA has elected to make a broad assumption in its calculation of costs that, should BPA decide to pursue MSTI as its preferred option,

[7] The MOU between BPA and NorthWestern may be found on BPA's SILS webpage at: http://transmission.bpa.gov/Customer_Forums/se_idaho/

and the project is successfully permitted and constructed, that BPA would be required to fund 50% of the project cost.

10. MSTI with Tap to Goshen Substation

Description:

This service arrangement would have BPA participate in MSTI, with an assumed ownership in facilities and bi-directional capacity of 50%.

In order to use MSTI capacity, BPA would need to deliver power to the proposed Townsend substation, the northern terminus of MSTI. BPA currently owns facilities necessary to transmit energy from the FCRPS to Townsend substation; however, the costs associated with facilities from Garrison substation to Townsend substation currently are accounted for separately in BPA's rates as an incremental rate assessed to users of that segment of BPA's network. To the extent BPA provides transmission service over Garrison to Townsend capacity, it reduces the directly assigned cost shares of the other Montana Intertie Agreement parties under the TGT rate schedule.

MSTI, as currently proposed, would extend from Townsend substation, past BPA's loads in southeast Idaho, to Midpoint substation. BPA would construct a tap line to connect existing facilities at or near Goshen substation to the MSTI line. Using this tap line BPA would be able to provide direct service to all loads served out of Goshen substation, including all of Lower Valley's loads and the majority of Fall River's loads. In addition, BPA would also construct a short line from Goshen substation to Sugar Mill substation to serve Idaho Falls. BPA would plan to energize both the tap line and the line to Idaho Falls no earlier than 2018.

Since BPA would not have constructed facilities to serve the load until 2018, an interim arrangement would be necessary to serve load between 2016 and 2018. BPA has assumed for cost analysis that a power purchase would be used, with OATT Service, during this interim period.

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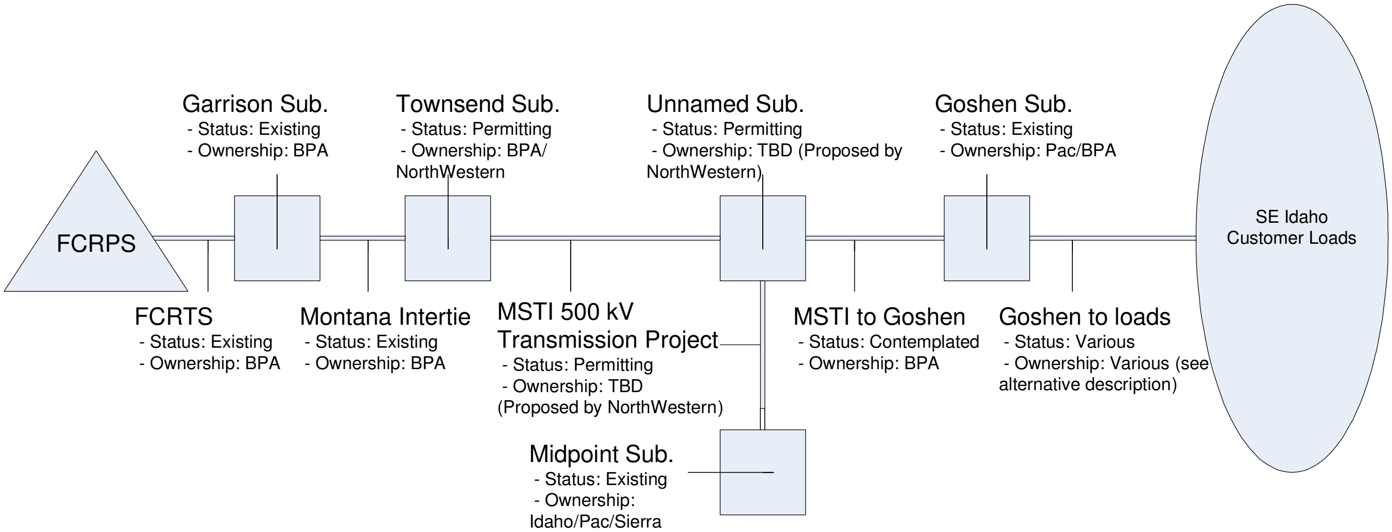

For summary of cost estimates, see Appendix D.

[8] This image of path displays Goshen substation as a placeholder. The actual substation used to serve load currently served by Goshen may change.

11. BPA 500 kV Construction – Montana to Goshen Substation

Description:

In examining options for extending the FCRTS to southeast Idaho, BPA selected extending the existing 500 kV transmission system from western Montana as the most cost effective option for initial scoping. This is due primarily to relative distance between the loads in southeastern Idaho and existing transmission facilities.

BPA has identified two variations on this extension. The first would have BPA construct a single circuit 500 kV line from Garrison substation directly to Goshen substation in southeast Idaho. This line would allow BPA to directly interconnect the loads behind Goshen substation, similar to the service provided by the MSTI option already described. Capacity provided by this line is estimated to be in excess of the loads, at about 600 MW. The projected increase in usable capacity is less than the MSTI option due to existing transmission constraints between Goshen and Midpoint substations. It might be possible to realize additional usable capacity at some point in the future through additional transmission reinforcement in Idaho.

Due to the significant permitting and design requirements of this project, BPA does not anticipate that a 500 kV connection between Garrison substation and Goshen substation could be energized until 2020. BPA would plan to energize the line from Goshen to Idaho Falls at a similar time, rather than in 2018 as is planned under the MSTI arrangement.

Since BPA would not have constructed facilities to serve the load until 2020, an interim arrangement would be necessary to serve load between 2016 and 2020. BPA has assumed for cost analysis that a power purchase would be used, with OATT Service, during this interim period.

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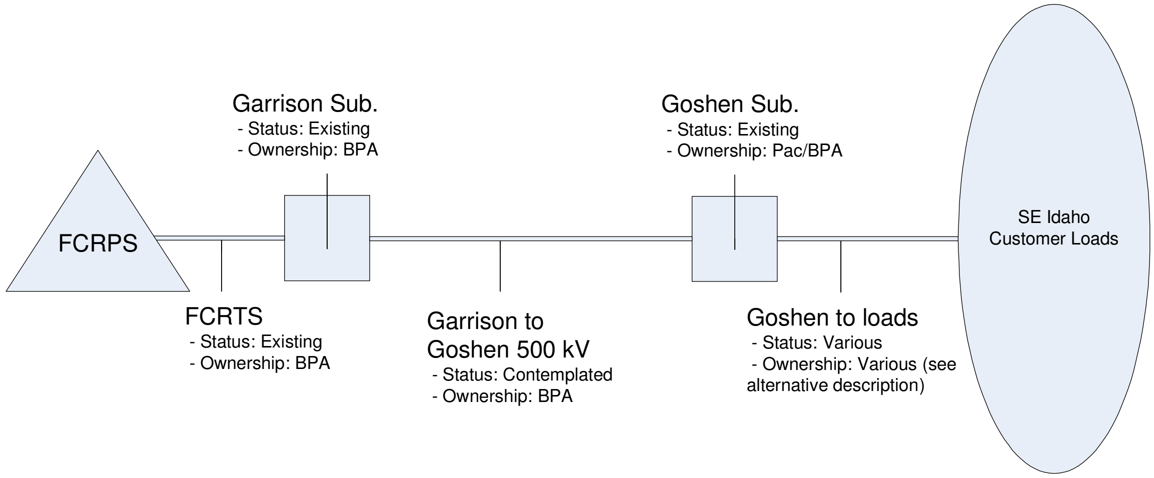

For summary of cost estimates, see Appendix E.

[9] This image of path displays Goshen substation as a placeholder. The actual substation used to serve load currently served by Goshen may change.

12. BPA 230 kV Construction – Montana to Goshen Substation

Description:

The second option identified as a possible BPA construction project to serve the SE Idaho Loads would also have BPA construct a line from Garrison substation directly to or near Goshen substation in southeast Idaho. However, this would be constructed and operated as a single circuit 230 kV line. A lower voltage interconnection would have several implications for service as compared to a 500 kV connection:

1. Lower cost to construct.
   i. BPA anticipates that construction of a single circuit 230 kV line between Garrison Substation and Goshen Substation would cost about $410m, which is $300m less expensive than a 500 kV construction. This cost includes bundled conductor, 70% series compensation and a phase shifter.
2. Lower capacity.
   i. BPA estimates that the total transfer capacity of a 230 kV line would be limited to around 400 MW of north to south capacity, and likely a smaller amount of northbound capacity. This would enable BPA to serve the load most of the year, but additional resource/capacity would be needed to serve winter peak loads.
   ii. It would not be possible to realize a material amount of additional usable capacity at some point in the future without building a parallel circuit.
3. Higher losses.
   i. Losses may be as high as 100 MW assuming 400 MW of transfers at the sending end. This occurs due to the high line length and loading levels compared with typical 230 kV lines.
   ii. BPA anticipates that the value of these additional losses will be significant, but has not included a valuation in this document. More analysis is needed to accurately quantify the loss implications of a 230 kV construction.

In this instance, BPA could proceed with the construction of a separate line from Goshen substation to Idaho Falls to interconnect that load to the BPA system as well.

Similar to service under MSTI and the 500 kV BPA build option, this service would also require some OATT Service from PacifiCorp for service to the customer loads that would remain connected to PacifiCorp transmission facilities.

Since BPA would not have constructed facilities to serve the load until 2020, an interim arrangement would be necessary to serve load between 2016 and 2020. BPA has assumed for cost analysis that a power purchase would be used, with OATT Service, during this interim period.

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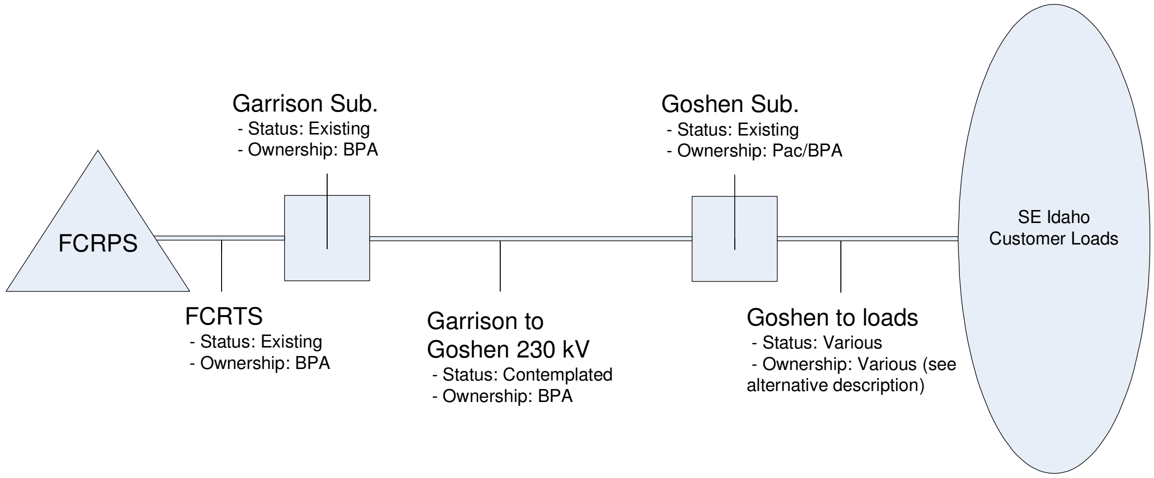


For summary of cost estimates, see Appendix E.

[10] This image of path displays Goshen substation as a placeholder. The actual substation used to serve load currently served by Goshen may change.

13. Benefit of Access to Southwest Power Markets:

For all transmission options, BPA anticipates that some benefit would be realized at certain times from the flexibility of being able to serve network loads on PacifiCorp's system with power from the FCRPS or power from southwest power markets, most notably Palo Verde. This benefit is compared to the current baseline of exclusively delivering power from the FCRPS to PacifiCorp's Westside system under the SIE.

Even greater benefits of access to Southwest Power Markets would accrue to BPA under the scenarios that include transmission construction all the way to SE Idaho. These expanded benefits would derive from the greater flexibility to market FCRPS surplus into the southwest power market (e.g. Palo Verde) in the high value summer months, and greater access to southwest Markets for purchasing winter power in the lower cost southwest market for delivery into the higher value pacific northwest market at MIDC. The MSTI and BPA Construction options would realize the greatest flexibility for accessing southwest power markets of all the construction options.

This potential for expanded benefits of greater access to southwest power markets would be limited under the B2H construction option. This is because BPA's capacity on B2H would be seasonally shaped to align with the shape of the SE Idaho Load, leaving little surplus capacity in the summer months to capitalize on access to high value southwest markets in the summer. Also, because BPA would not have any significant allocation of east to west capacity on B2H, BPA's ability to deliver lower cost winter capacity and energy from the southwest into the pacific northwest over B2H would be limited.

14. Cost Summary

Below is a summary of estimated costs for each of the options identified in this document. All estimates in this document are preliminary, and heavily reliant on assumptions and in some cases use of public estimates and information.

(Values in table shown in millions of dollars, nominal)

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
Current Service - SIE & GTA	*$11.3*	*$11.3*	*??*	*??*	*??*	*??*	*??*	*??*	*??*	*??*	*??*	*??*	*??*	*??*	*??*
Power Purchase + OATT	$0.0	$0.0	$22.1	$25.1	$34.2	$35.1	$39.4	$44.5	$44.8	$45.5	$46.3	$46.8	$47.5	$48.2	$48.9
B2H + OATT	$0.0	$0.0	$25.1	$31.0	$41.5	$42.0	$46.5	$51.0	$51.5	$51.9	$52.4	$53.4	$54.5	$55.6	$56.6
B2H + Transmission Asset Swaps	$0.0	$0.0	$25.9	$32.6	$24.3	$24.4	$24.4	$24.4	$24.4	$24.4	$24.4	$25.1	$25.7	$26.3	$26.9
MSTI with Tap	$0.0	$7.5	$38.2	$39.2	$50.3	$50.4	$51.5	$52.6	$52.7	$52.8	$54.5	$56.3	$58.1	$59.9	$61.8
BPA 500 kV Construction	$0.0	$0.0	$22.1	$25.1	$45.1	$56.9	$63.0	$64.1	$64.2	$64.3	$64.5	$64.6	$64.7	$67.0	$69.3
BPA 230 kV Construction	$0.0	$0.0	$22.1	$25.1	$40.6	$47.9	$40.2	$41.3	$41.1	$41.3	$41.3	$41.5	$41.6	$42.6	$44.0

Key Assumptions for Transmission Project Costing:

- All analysis above and in appendices assumes full lease-financing of all capital expenditures for construction of transmission facilities. This assumption oversimplifies typical lease financing arrangements as not all assets associated with the construction of transmission facilities would be eligible for lease financing. Should BPA decide to fund construction of any transmission projects, a portion of the estimated construction cost would likely impact BPA's treasury borrowing authority, such as the cost associated with land and access roads.

- Lease financing throughout document assumes 2 year construction lease at 3% followed by a 30 year lease at 7%.

- Net present valuation for transmission assets are included in the appendices and use BPA’s standard discount rate for transmission investments, 9%.

- No costs are included in this analysis for property taxes associated with lease financed lines. Treatment of property taxes for lease financed assets varies by state and would depend on the specifics of BPA’s ownership in the assets.

- O&M for all new assets is assumed to be 0.5% of direct cost per year for the first seven years following construction, and then ramps up to 3% in year 14.

More detailed information on some of the components of each of these costs may be found in Appendices B-E.

Appendix A: Loads and Resources

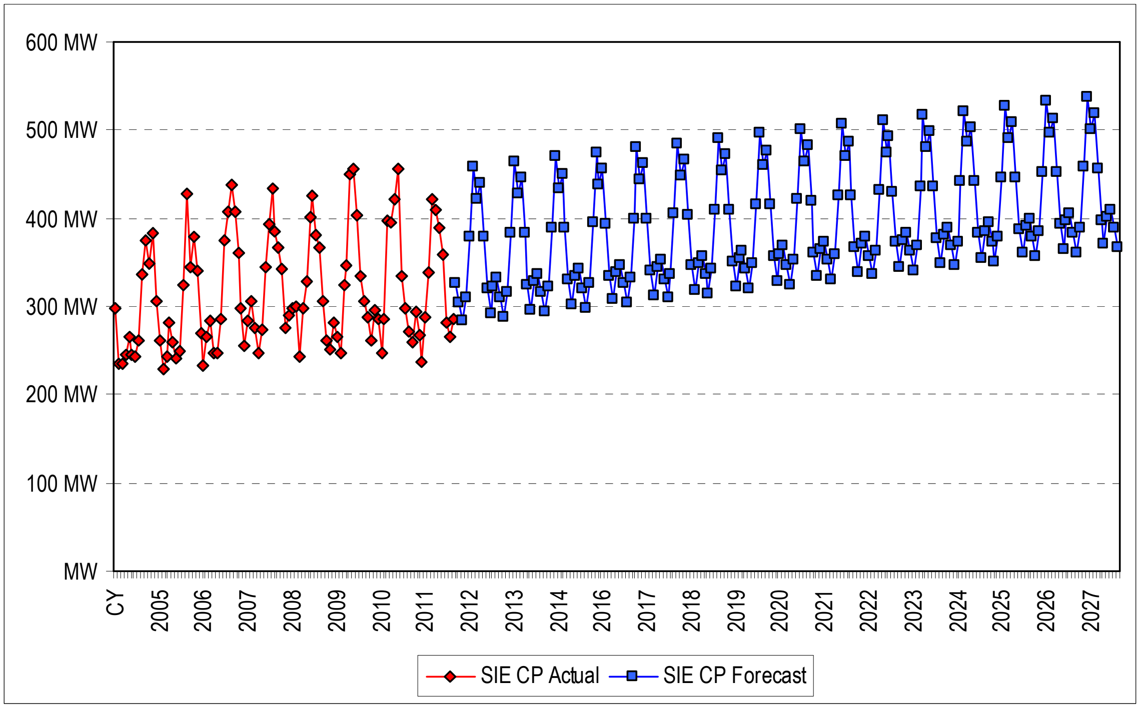
Below, Table 1 shows SE Idaho Customer peak loads by month and calendar year, in megawatts (MW). Graph 1 displays values from Table 1.

Table 1: Coincidental Peak Loads (MW) of SE Idaho Customers

(CY)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2004										262	336	375
2005	349	382	307	261	230	243	281	260	242	248	323	428
2006	345	378	341	270	232	265	284	248	246	285	375	408
2007	437	407	361	298	256	284	307	276	248	273	344	392
2008	433	385	367	344	276	289	298	301	243	298	328	402
2009	427	381	368	305	261	251	282	266	248	324	347	450
2010	456	404	335	307	288	261	297	285	247	287	397	394
2011	421	455	334	298	272	259	295	268	237	289	338	422
2012	410	390	359	282	265	286	326	305	283	311	379	459
2013	422	440	378	319	292	323	332	310	288	316	384	464
2014	428	445	383	325	297	328	337	316	293	321	389	469
2015	433	451	389	330	302	333	342	321	299	327	394	475
2016	438	456	394	335	307	339	347	326	304	332	400	480
2017	443	461	399	340	313	344	353	331	309	337	405	485
2018	449	466	404	346	318	349	358	337	314	342	410	490
2019	454	472	410	351	323	354	363	342	320	348	415	496
2020	459	477	415	356	328	360	368	347	325	353	421	501
2021	464	482	420	362	334	365	374	352	330	358	426	506
2022	470	487	425	367	339	370	379	358	335	363	431	511
2023	475	493	431	372	344	375	384	363	341	369	436	517
2024	480	498	436	377	349	381	389	368	346	374	442	522
2025	485	503	441	383	355	386	395	373	351	379	447	527
2026	491	508	446	388	360	391	400	379	356	384	452	532
2027	496	514	452	393	365	396	405	384	362	390	457	538
2028	501	519	457	398	370	402	410	389	367			

Red denotes actual load.
Blue denotes forecasted load.

Graph 1: Coincidental Peak Loads (MW) of SE Idaho Customers



Below, Table 2 shows SE Idaho Customer average energy loads by month and calendar year, in megawatts (aMW). Graph 2 displays values from Table 2.

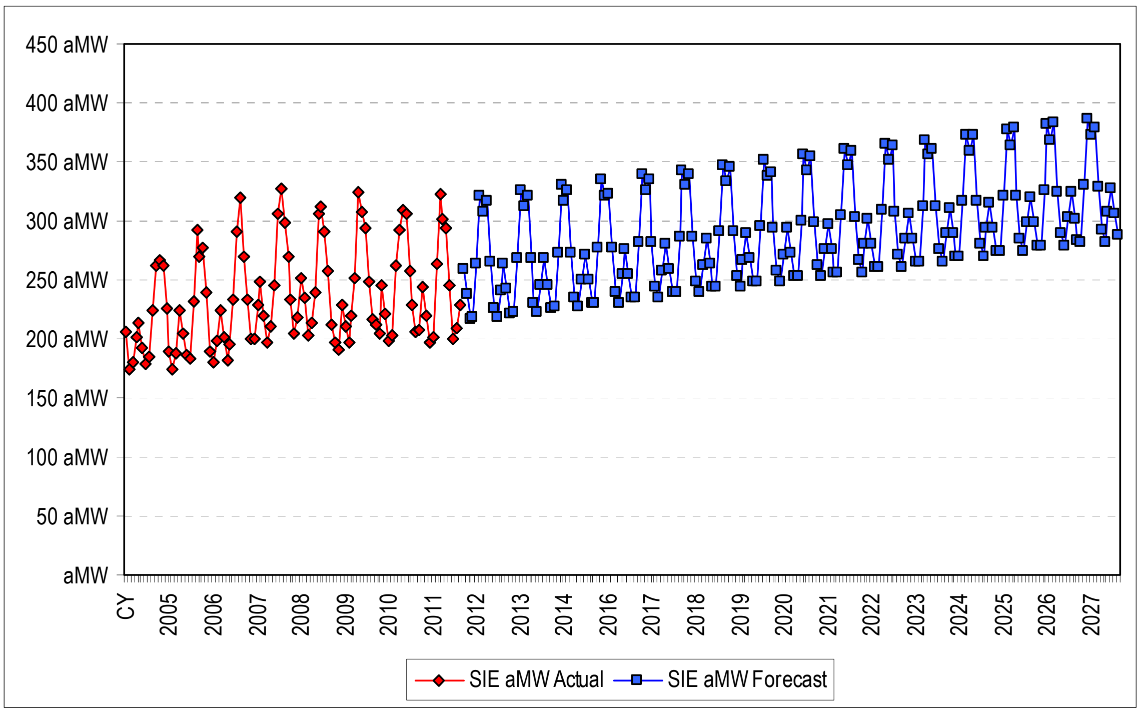
Table 2: Average Energy Loads (aMW) of SE Idaho Customers

(CY)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2004			206	175	181	202	214	193	179	184	225	263
2005	267	262	226	190	175	188	224	205	186	183	232	293
2006	269	278	239	189	180	199	224	202	182	195	234	291
2007	320	270	233	200	199	229	249	219	198	210	246	306
2008	327	298	269	233	205	218	252	235	203	214	239	306
2009	312	290	257	212	197	191	229	211	197	219	251	324
2010	307	294	249	216	213	205	246	222	198	203	261	292
2011	309	306	258	229	207	207	243	220	197	202	264	322
2012	302	293	246	201	210	229	259	238	217	218	264	322
2013	308	316	265	226	218	240	263	242	221	222	268	326
2014	312	321	269	231	222	245	268	246	226	227	273	330
2015	317	326	273	235	227	249	272	250	230	231	277	335
2016	321	323	277	240	231	254	276	255	235	235	282	339
2017	325	335	282	244	235	258	281	259	239	239	286	343
2018	330	340	286	249	239	263	285	263	243	244	291	347
2019	334	345	290	253	244	267	289	268	248	248	295	352
2020	338	342	295	258	248	272	293	272	252	252	300	356
2021	342	354	299	262	252	276	298	276	257	257	304	360

2022	347	359	303	266	257	280	302	281	261	261	308	365
2023	351	364	308	271	261	285	306	285	266	265	313	369
2024	355	360	312	275	265	289	311	289	270	270	317	373
2025	360	373	316	280	270	294	315	293	275	274	322	378
2026	364	378	320	284	274	298	319	298	279	278	326	382
2027	368	383	325	289	278	303	324	302	283	282	331	386
2028	373	378	329	293	282	307	328	306	288			

Red denotes actual load.
Blue denotes forecasted load.

Graph 2: Average Energy Loads (aMW) of SE Idaho Customers



Below Table 3 shows historic generation at each of these projects under average and critical water.

Table 3: Average (aMW) of Generation in Average and Critical Water

	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	
Average Generation													**Average**
Palisades	125.8	98.4	58.4	37.0	19.4	48.9	47.7	52.1	82.5	133.4	147.7	149.4	83.6
Bulbs	13.8	14.5	15.6	19.0	20.9	21.2	21.3	19.6	16.1	12.7	14.2	14.2	16.9
Sum	139.6	112.9	74.1	56.0	40.4	70.1	69.1	71.7	98.6	146.1	161.8	163.6	100.5
Critical Generation (1936-1937)													**Average**
Palisades	117.9	105.1	45.5	11.3	11.2	11.4	12.8	28.2	51.7	152.2	151.5	127.1	69.2
Bulbs	9.7	10.6	13.2	16.5	21.6	22.3	20.7	14.4	9.9	6.7	9.9	12.5	14.0
Sum	127.7	115.7	58.7	27.8	32.7	33.6	33.5	42.6	61.6	158.9	161.3	139.6	83.1

Appendix B: Cost Estimates for Power Purchase Option

For illustrative purposes, BPA has assumed that 100 percent of the power serving SE Idaho customers is purchased power delivered into the PACE system. BPA believes this represents a conservative (high cost) estimate of the potential incremental cost of power under OATT Service. BPA further assumes that BPA purchases physical call options to firm up the top two quartiles of BPA's peak power needs all 12 months, with a strike price at $5 MWh premium to market.

The costs below are derived from estimated forward price curves through 2020 for MIDC and Palo Verde, plus the purchase of call options at a cost of $8.50 MWh ($3.54 kW-month)

While BPA believes that the estimate of net power purchase costs can be reasonably considered to be a high cost estimate, there is considerable uncertainty around the future direction, magnitude and volatility of power price differentials between MIDC and PACE power markets. These uncertainties include:

- Future fuel price basis differentials between generation in the PNW and Rocky Mountains
- Changes in regional capacity reserve margins across regions over time
- Increases and decreases in transmission congestion between regions
- Regulatory policies that differentially affect resource development and resource retirements between regions, especially coal plant retirements

(Values in table shown in millions of dollars, nominal)

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
1) Cost of Power Purchase	$0.0	$0.0	$2.8	$4.9	$8.6	$9.0	$8.8	$9.4	$9.3	$9.6	$9.9	$9.9	$10.2	$10.4	$10.6
2) Cost of Pac OATT Service	$0.0	$0.0	$19.2	$20.1	$25.6	$26.1	$30.6	$35.1	$35.5	$36.0	$36.4	$36.9	$37.4	$37.9	$38.4
Total Cost of Power Purchase Option	**$0.0**	**$0.0**	**$22.1**	**$25.1**	**$34.2**	**$35.1**	**$39.4**	**$44.5**	**$44.8**	**$45.5**	**$46.3**	**$46.8**	**$47.5**	**$48.2**	**$48.9**

Line 1: Estimated cost of power purchase

- Assumes year-round monthly block power purchases from SW (Palo Verde) market
- Includes the annual cost of sufficient capacity options to firm SW market purchases for the top two quartiles of monthly peak load
- Costs are net of estimated value of power displaced back into the MIDC market

Line 2: Estimate of potential cost of OATT Service from PacifiCorp

- OATT Service begins in July of 2016 after SIE and GTA expire
- Starting OATT rates based upon PacifiCorp 2011 formula rate filing
- Assumes PacifiCorp completes and places into rate base all proposed Gateway transmission investments plus B2H and Cascade Crossing capital investments, as outlined in PacifiCorp's 2012 IRP Update
    - Capital projects enter rate base in the latest year identified in the IRP update
    - No CWIP in rate base
- Rate-based non-major capital project, replacements and capital maintenance is assumed to total 213 million in 2016 escalating at 2 percent annually.
- Includes cost of all PacifiCorp supplied ancillary services
- Includes cost of transmission losses @4.8% of load valued at $35 MWh.

Appendix C: Cost Estimates for B2H Options

B2H with OATT Service:

(Values in table shown in millions of dollars, nominal)

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
1) Lease Cost for B2H	$0.0	$0.0	$3.0	$6.0	$13.9	$13.9	$13.9	$13.9	$13.9	$13.9	$13.9	$13.9	$13.9	$13.9	$13.9
2) Cost of O&M	$0.0	$0.0	$0.0	$0.0	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$1.4	$2.0	$2.6	$3.2
3) Cost of Pac OATT Service	$0.0	$0.0	$0.0	$0.0	$25.6	$26.1	$30.6	$35.1	$35.5	$36.0	$36.4	$36.9	$37.4	$37.9	$38.4
4) Cost Inc of Existing OATT Service	$0.0	$0.0	$0.0	$0.0	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2
5) Cost of Bridge Power Purchase	$0.0	$0.0	$22.1	$25.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Cost of B2 + OATT Option	**$0.0**	**$0.0**	**$25.1**	**$31.0**	**$41.5**	**$42.0**	**$46.5**	**$51.0**	**$51.5**	**$51.9**	**$52.4**	**$53.4**	**$54.5**	**$55.6**	**$56.6**

Line 1: Estimated cost of lease-financing BPA's share of B2H

- BPA's estimated share of construction cost: $198.8m[11]
- Constructed FY 2016 & FY 2017, in service FY 2018
- Nominal value of lease payments: $625.2m
- NPV over term of lease: $101.5

Line 2: Estimated cost of O&M

- Assumed to be 0.5% of direct cost per year for the first seven years following construction, and then ramps up to 3% in year 14

Line 3: Estimate of potential cost of OATT Service from PacifiCorp

- Begins in 2016 (although separately included as part of line 5 for 2016-2017)
- Makes significant assumptions regarding large PacifiCorp capital improvements, partially based on PacifiCorp IRP
- Assumes formula rates

Line 4: Estimate of cost increases for existing OATT Service

- Addresses cost of B2H as pertains to existing OATT Service BPA acquires from Idaho Power and PacifiCorp

[11] Based on BPA's share of B2H in JFA – 24.24%

Line 5: Estimated cost of power purchase for bridge

- Same as line 1 in Appendix B, except that power purchases would be used to serve load only in FY 2016-2017
    - Includes PacifiCorp OATT Service
- Continue line 2's assumption of in service date of BPA facilities of FY 2018

B2H with Asset Swap:

(Values in table shown in millions of dollars, nominal)

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
1) Lease Cost for B2H	$0.0	$0.0	$3.0	$6.0	$13.9	$13.9	$13.9	$13.9	$13.9	$13.9	$13.9	$13.9	$13.9	$13.9	$13.9
2) Cost of O&M	$0.0	$0.0	$0.0	$0.0	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8	$1.4	$2.0	$2.6	$3.2
3) Cost of BPA BAA Ancillaries	$0.0	$0.0	$0.0	$0.0	$1.7	$1.7	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.9	$1.9	$1.9
4) Lost Revenue for Pac Asset Swap	$0.0	$0.0	$0.0	$0.0	$2.9	$2.9	$2.9	$2.9	$2.9	$2.9	$2.9	$2.9	$2.9	$2.9	$2.9
5) Cost of Lease for Asset Swap	$0.0	$0.0	$0.8	$1.6	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8	$3.8
6) Cost Inc of Existing OATT Service	$0.0	$0.0	$0.0	$0.0	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2	$1.2
7) Cost of Bridge Power Purchase	$0.0	$0.0	$22.1	$25.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Cost of B2 + Asset Swap Option	**$0.0**	**$0.0**	**$25.9**	**$32.6**	**$24.3**	**$24.4**	**$24.4**	**$24.4**	**$24.4**	**$24.4**	**$24.4**	**$25.1**	**$25.7**	**$26.3**	**$26.9**

8) Opportunity Cost for IPCo Swap	$0.0	$0.0	$7.3	$7.3	$7.3	$7.3	$7.3	$7.3	$7.3	$7.3	$7.3	$7.3	$7.3	$7.3	$7.3

Line 1: Estimated cost of lease-financing BPA's share of B2H

- Same as line 1 in B2H with OATT

Line 2: Estimated cost of O&M

- Assumed to be 0.5% of direct cost per year for the first seven years following construction, and then ramps up to 3% in year 14

Line 3: Cost of providing Ancillary Services

- Assumes that as part of transmission asset swap, BPA brings SE Idaho Loads into the BPA BAA
- Priced at BPA's current posted tariff rates
- Only Schedules 3, 5 and 6 for regulation and frequency response, and reserves

Line 4: Estimate of lost revenue associated with assets provided to PacifiCorp

- Begins in 2016 (although separately included as part of line 5 for 2016-2017)
- Assumes PacifiCorp service to central Oregon
- Amount of asset swapped based on net book value associated with Pac assets on eastside

Line 5: Estimate of cost of lease-financing necessary improvements between Hemingway Substation to SE Idaho Load

- Includes upgrades to Idaho Power transmission system that BPA would participate in to be able to serve SE Idaho Load
  - Estimated cost to BPA of improvements is $19.0m
- Also includes small stake in Gateway West (Populus to Hemingway only) to facilitate westbound transfer of Palisades generation
  - This small stake is roughly equivalent to BPA's 97 MW westbound potential right on B2H, as specified in the permitting agreement
  - Estimated cost to BPA of Gateway West assets is $34.5m
- BPA's total estimated cost of construction is $53.5m
- Constructed FY 2016 & FY 2017, in service FY 2018
- Nominal value of lease payments: $169.8m
- NPV over term of lease: $27.6m

Line 6: Estimate of cost increases for existing OATT Service

- Same as line 3 in B2H with OATT

Line 7: Estimated cost of power purchase for bridge

- Same as line 1 in Appendix B, except that power purchases would be used to serve load only in FY 2016-2017
  - Includes PacifiCorp OATT Service
- Continue line 2's assumption of in service date of BPA facilities of FY 2018

Line 8: Estimate of potential lost revenue associated with assets provided to Idaho Power

- Not included in sum since BPA does not currently receive revenue for assets that would be swapped to Idaho Power, opportunity cost of transaction
- Number displayed is a maximum, assumes that all capacity provided by swapped assets would be sold year-round

Appendix D: Cost Estimates for MSTI Option

(Values in table shown in millions of dollars, nominal)

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
1) Lease Cost for MSTI	$0.0	$7.5	$15.0	$35.0	$35.0	$35.0	$35.0	$35.0	$35.0	$35.0	$35.0	$35.0	$35.0	$35.0	$35.0
2) Lease Cost for BPA Const.	$0.0	$0.0	$1.1	$2.2	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0	$5.0
3) Cost of O&M	$0.0	$0.0	$0.0	$2.1	$2.4	$2.4	$2.4	$2.4	$2.4	$2.4	$3.8	$5.5	$7.2	$8.9	$10.6
4) Cost of BPA BAA Ancillaries	$0.0	$0.0	$0.0	$0.0	$1.7	$1.7	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.9	$1.9	$1.9
5) Cost of Partial Pac OATT Service	$0.0	$0.0	$0.0	$0.0	$6.1	$6.3	$7.3	$8.4	$8.5	$8.6	$8.7	$8.9	$9.0	$9.1	$9.2
6) Cost of Bridge Power Purchase	$0.0	$0.0	$22.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Cost of MSTI Option	**$0.0**	**$7.5**	**$38.2**	**$39.2**	**$50.3**	**$50.4**	**$51.5**	**$52.6**	**$52.7**	**$52.8**	**$54.5**	**$56.3**	**$58.1**	**$59.9**	**$61.8**

Line 1: Estimated cost of lease-financing BPA's share of MSTI

- BPA's estimated share of construction cost: $500m[12]
- Constructed FY 2015 & FY 2016, in service FY 2017
- Nominal value of lease payments: $1575.5m
- NPV over term of lease: $279.4m

Line 2: Estimated cost of lease-financing BPA's share of limited BPA construction in SE Idaho

- Includes tap line and line to Idaho Falls, together serve about 76% of SE Idaho Load
- BPA's estimated share of construction cost: $72m
- Constructed FY 2016 & FY 2017, in service FY 2018
- Nominal value of lease payments: $226.4m
- NPV over term of lease: $36.7m

Line 3: Estimated cost of O&M

- Assumed to be 0.5% of direct cost per year for the first seven years following construction, and then ramps up to 3% in year 14

[12] Based on assumed 50% share, as described in the body of this document

Line 4: Cost of providing Ancillary Services

- Assumes BPA brings portion of SE Idaho Loads served behind Goshen or in Idaho Falls into the BPA BAA
- Priced at BPA's current posted tariff rates
- Only Schedules 3, 5 and 6 for regulation and frequency response, and reserves

Line 5: Estimate of potential cost of partial OATT Service from PacifiCorp

- Only needed for portion of load not directly served by BPA facilities, about 24%[13]
- Begins in 2016 (although separately included as part of line 5 for 2016-2017)
- Makes significant assumptions regarding large PacifiCorp capital improvements, partially based on PacifiCorp IRP
- Assumes formula rates for PacifiCorp

Line 6: Estimated cost of power purchase for bridge

- Same as line 1 in Appendix B, except that power purchases would be used to serve load only in FY 2016-2017
    - Includes PacifiCorp OATT Service
- Continues line 2's assumption of in service date of BPA facilities of FY 2018

[13] Based on evaluation of average loads, about 24% of the SE Idaho Load is not associated with service out of Goshen substation or to Idaho Falls

Appendix E: Cost Estimates for BPA Construction Options

500 kV BPA Construction:

(Values in table shown in millions of dollars, nominal)

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
1) Nominal Lease Cost for BPA Construction	$0.0	$0.0	$0.0	$0.0	$10.9	$21.8	$50.9	$50.9	$50.9	$50.9	$50.9	$50.9	$50.9	$50.9	$50.9
2) Cost of O&M	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$3.0	$5.2	$7.3
3) Cost of BPA BAA Ancillaries	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.9	$1.9	$1.9
4) Cost of Partial Pac OATT Service	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$7.3	$8.4	$8.5	$8.6	$8.7	$8.9	$9.0	$9.1	$9.2
5) Cost of Bridge Power Purchase	$0.0	$0.0	$22.1	$25.1	$34.2	$35.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Cost of BPA 500 kV Option	**$0.0**	**$0.0**	**$22.1**	**$25.1**	**$45.1**	**$56.9**	**$63.0**	**$64.1**	**$64.2**	**$64.3**	**$64.5**	**$64.6**	**$64.7**	**$67.0**	**$69.3**

Line 1: Estimated cost of lease-financing BPA's construction to and in SE Idaho

- Includes 500 kV line from Garrison to Goshen and line to Idaho Falls, together serve about 76% of SE Idaho Load
- BPA's estimated share of construction cost: $727m
- Constructed FY 2018 & FY 2019, in service FY 2020
- Nominal value of lease payments: $2,286.4m
- NPV over term of lease: $308.9m

Line 2: Estimated cost of O&M

- Assumed to be 0.5% of direct cost per year for the first seven years following construction, and then ramps up to 3% in year 14

Line 3: Cost of providing Ancillary Services

- Assumes BPA brings portion of SE Idaho Loads served behind Goshen or in Idaho Falls into the BPA BAA
- Priced at BPA's current posted tariff rates
- Only Schedules 3, 5 and 6 for regulation and frequency response, and reserves

Line 4: Estimate of potential cost of partial OATT Service from PacifiCorp

- Only needed for portion of load not directly served by BPA facilities, about 24%
- Otherwise, same as Line 2 of B2H + OATT

Line 5: Estimated cost of power purchase for bridge

- Same as line 1 in Appendix B, except that power purchases would be used to serve load only in FY 2016-2019
    - Includes PacifiCorp OATT Service
- Continue line 1's assumption of in service date of BPA facilities of FY 2020

230 kV BPA Construction:

(Values in table shown in millions of dollars, nominal)

	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
1) Nominal Lease Cost for BPA Construction	$0.0	$0.0	$0.0	$0.0	$6.4	$12.8	$29.9	$29.9	$29.9	$29.9	$29.9	$29.9	$29.9	$29.9	$29.9
2) Cost of O&M	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$3.0	$4.3
3) Cost of BPA BAA Ancillaries	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.8	$1.8	$1.8	$1.8	$1.8	$1.8	$1.9	$1.9	$1.9
4) Cost of Partial Pac OATT Service	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$6.8	$7.9	$7.7	$7.9	$7.9	$8.0	$8.1	$7.8	$7.9
5) Cost of Bridge Power Purchase	$0.0	$0.0	$22.1	$25.1	$34.2	$35.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Cost of BPA 230 kV Option	**$0.0**	**$0.0**	**$22.1**	**$25.1**	**$40.6**	**$47.9**	**$40.2**	**$41.3**	**$41.1**	**$41.3**	**$41.3**	**$41.5**	**$41.6**	**$42.6**	**$44.0**

Line 1: Estimated cost of lease-financing BPA's construction to and in SE Idaho

- Includes 230 kV line from Garrison to Goshen and line to Idaho Falls, together serve about 76% of SE Idaho Load
- BPA's estimated share of construction cost: $427m
- Constructed FY 2018 & FY 2019, in service FY 2020
- Nominal value of lease payments: $1,342.9m
- NPV over term of lease: $181.4m

Line 2: Estimated cost of O&M

- Assumed to be 0.5% of direct cost per year for the first seven years following construction, and then ramps up to 3% in year 14

Line 3: Cost of providing Ancillary Services

- Assumes BPA brings portion of SE Idaho Loads served behind Goshen or in Idaho Falls into the BPA BAA
- Priced at BPA's current posted tariff rates
- Only Schedules 3, 5 and 6 for regulation and frequency response, and reserves

Line 4: Estimate of potential cost of partial OATT Service from PacifiCorp

- Only needed for portion of load not directly served by BPA facilities, about 24%
- Makes significant assumptions regarding large PacifiCorp capital improvements, partially based on PacifiCorp IRP
- Assumes formula rates for PacifiCorp

- Also includes the cost of power purchases for when load expected to exceed 400 MW (winter months), net of displaced power into Mid-C, similar to analysis in Appendix B

Line 5: Estimated cost of power purchase for bridge

- Same as line 1 in Appendix B, except that power purchases would be used to serve load only in FY 2016-2019
    - Includes PacifiCorp OATT Service
- Continue line 1's assumption of in service date of BPA facilities of FY 2020