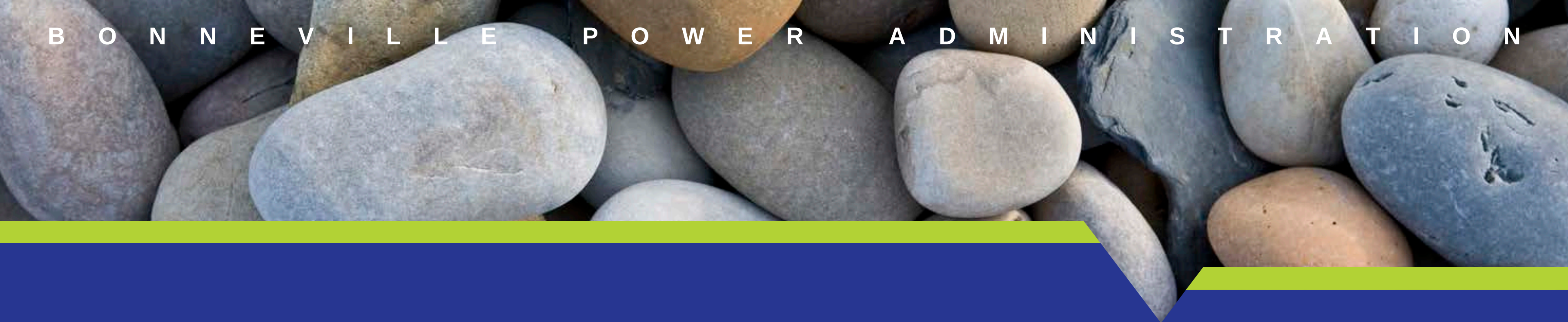

Investment summaries

Capital investments in play in the agency-level prioritization process

Cycle 17-1

November 2016

Investments covered by the agency-level prioritization process

Prioritized through asset strategies

Prioritized through new process

"Core" Sustain Investment

Investment the primary purpose of which is to replace existing assets in order to maintain system performance and capability

Expansion and "Non-Core" Sustain Investment

Investment that "grows" the asset base, i.e., adds capacity or new capabilities, or that increases operational output or productivity. Also includes sustain investment that is "non-core"

Compliance – 3 years
Investment must occur in next 3-years in order to comply with **contract, order, or directive**

Policy Commitment – 3 Years
Investment must occur next 3 years to fulfill commitments made by the agency

Discretionary -3 years
Investment that may be valuable, but can be deferred

Funded first

Funded with remaining capital that the agency has budgeted

Energy efficiency and fish and wildlife investments are exempt because they are prioritized through regional processes. Until FY 2018, investments in transmission, IT, facilities and federal hydro are also exempt if they have an estimated capital cost of $3M or less

The prioritization window for Cycle 5: FYs 2016-2018

The investment summaries that follow are for reference purposes. They cover the investments that were nominated and that are in play in Cycle 17-1 (May 2016 – October 2016).

If an investment's benefits were not assessed, we included a 2-page narrative summary without financial ratio results.

If the investment's benefits were assessed, a "dashboard" is added to show key results for economic and financial metrics.

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Control Center CIPv5 Compliance
Classification: Compliance
Sponsoring Asset Category: Transmission

What is the proposed investment?

This investment is the FY15 New Start Control Center Sustain work. All of this work is driven by very tight NERC CIPv5 compliance deadlines in April 2016. The investment:

• End of life upgrades and migrations of major systems to the new network environment (NERC-CIP-003-011 for each system)
• DART System
• OPI System (includes upgrade and consolidation of the TOT study system)
• Current Infrastructure Management Systems (Active Directory and Backup Storage systems)additions into the new environment to support the systems (NERC-CIP-003-011)

OP_CABRptText1

Why is this investment needed?

The investment is need to fulfill the control center requirements of the NERC CIPv5 initiatives.

What assumptions are behind the investment need?

OP_CABRptText2

It is assumed that the investment will be complete by April 2016 in order to meet NERC CIPv5 compliance requriements. At this point, the materials are expected to have little variability - the main variable in the project is the cost of the labor resources required to implement the project.

OP_CABRptText3

What actions would be taken if this investment were not made?

The control center system and components backlog would increase and BPA would be subject to directives and consequences related to failing to comply with NERC CIPv5 deadlines until such investments are made. This would likely include an expedited version of this investment, which would be more costly.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

The alternative to this investment would be to remain with status quo systems and be non-compliant with CIP v5

OP_CABRptText5

Who would benefit from this investment?

Largely System Operations (TO); also, the new Tx Cybersecurity Program overseeing the CIPv5 implementation across Tx. Also, TPO from a standpoint of the CC Asset Program.

Control Center CIPv5 Compliance

OP_CABRptText6

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Feb-15	Dec-16	Feb-17	Apr-17	$6,815	$7,815	$9,550	$5,257	$2,838	$1,336	$0	$0	$0	$9,431	11%	5	7	10

What drives the investment costs to be low or high?

Labor cost is the major driver in cost variability. If expertise is not available in-house, resources may need to be contracted at additional cost. Material costs are expected to have little or no variability.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$2	$56	$54
Present value:	$11	$347	$336

Control Center CIPv5 Compliance

Fossil-DeMoss Shunt Reactive
Classification: Compliance
Sponsoring Asset Category: Transmission

What is the proposed investment?

Installation of a 4 - MVAR Shunt Reactor at Fossil Substation 69 kV bus. A shunt reactor will be able to provide reactive support to the system during high voltage events. Installation of a 4-MVAR Shunt Capacitor at DeMoss. A shunt Capacitor will be able to provide reactive support to the system during low voltage events.

OP_CABRptText1

Why is this investment needed?

This project is needed for two reasons: 1) to support local area load growth. During peak winter load conditions with local area wind not generating, this outage can cause low voltages as well as local area load loss. 2) to support PATU and Condon wind generation. During low to average load level conditions a single line outage of Big Eddy-DeMoss 115 line can cause high area voltages (above 1.10 PU) with or without wind generating.

What assumptions are behind the investment need? OP_CABRptText2

OP_CABRptText3

What actions would be taken if this investment were not made?

During low to average load level conditions a single line outage of Big Eddy-DeMoss 115 line can cause high area voltages (above 1.10 PU) with or without wind generating. In addition, during During low to average load level conditions a single line outage of Big Eddy-DeMoss 115 line can cause high area voltages (above 1.10 PU) with or without wind generating. In addition, during peak winter load conditions with local area wind not generating, this outage can cause low voltages and potential local area load loss.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

There is currently a project underway to install shunt reactors at DeMoss substation, which affects the same load area. The reactors will help with the high voltages we are seeing in the area, but not the low voltages. If the reactor project is not installed, a larger reactor will be needed at Fossil. An investment alternative would be to install a single STATCOM at Fossil Substation. However, a STATCOM would be much more expensive and since we don't have any other low voltage STATCOMs on the BPA system, maintenance costs and life span are difficult to estimate. If we do nothing, we will experience local area load loss for a single contingency and thus violate NERC Reliability Standard TPL-002.

OP_CABRptText5

Who would benefit from this investment?

This project will prevent future load loss caused by loss of the Big Eddy-DeMoss 115kV line outage. Also, this area has been experiencing high voltages during light load/high wind generation and low voltages during high load/low wind generation. This can cause outages and equipment damage for our customers along the DeMoss-Fossil-Maupin line (Wasco Electric Coop, Northern Wasco PUD and Columbia Basin Electric Coop). This project will alleviate these voltage swings and keep our customers satisfied

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Jul-16	Sep-17	Apr-18	Dec-18	$2,000	$2,022	$3,000	$0	$125	$1,254	$1,128	$0	$0	$2,507	0%	30	40	65

What drives the investment costs to be low or high?

Low: This assumes good soil (easy to dig), breaker mfg is clearly defined. No land or control house expansion, in house

High: This assumes a control house expansion is necessary. The project goes CMO and requires substantial environmental work. High excavation costs.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$11	$14	$4
Present value:	$254	$341	$86

Fossil-DeMoss Shunt Reactive

Golden Hills Interconnection - G0099_2
Classification: Compliance
Sponsoring Asset Category: Transmission

What is the proposed investment?

The Golden Hills wind project will interconnect to the John Day – Biglow Canyon 230 kV line at structure 1/1. The line from Biglow Canyon (located at structure 5/1) to structure 1/1 is constructed, but not energized. To energize the line, two 230 kV PCB's will be constructed at Biglow Canyon to fully loop-in the 230 kV line. A new parcel of land is needed in order to install the two 230 kV breakers. PGE owns this parcel and has indicated willingness to sell if this project goes forward. Communications, SCADA, and meters will be placed at the Golden Hills collector substation.

OP_CABRptText1

Why is this investment needed?

BP Alternative Energy North America requested interconnection of its 200 MW Golden Hills Wind Project to the BPA system. The project and LGIA has since been transferred to Orion Golden Hills Wind, LLC. With BPA's existing transmission infrastructure, the customer's requested load service cannot be fulfilled. The Golden Hills Wind Project is contingent on a power purchase agreement, which the customer does not have at this time. In the event that the customer would like to proceed, BPA will be expected to allow the project to interconnect.

OP_CABRptText2

What assumptions are behind the investment need?

The assumption is that the customer decides to move forward after receiving a power purchase agreement.

OP_CABRptText3

What actions would be taken if this investment were not made?

BPA is obligated by an LGIA to interconnect the Golden Hills Wind Project as long as the customer indicates readiness to proceed by November 15, 2016.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

The selected plan of service is the only plan of service that would interconnect the customer.

OP_CABRptText5

Who would benefit from this investment?

TPC, TEP, Transmission design groups, TPO, TPP, TPM, TOT, TOD

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Nov-16	Sep-18	Dec-18	Jul-19	$3,500	$3,900	$4,500	$0	$0	$1,693	$2,418	$725	$0	$4,836	0%	30	40	50

What drives the investment costs to be low or high?
The costs could be lower or higher than expected due to changes in material pricing and market rates.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$0	$0
Present value:	$0	$0	$0

Golden Hills Interconnection - G0099_2

Information Governance and eDiscovery
Classification: Compliance
Sponsoring Asset Category: IT

What is the proposed investment?

BPA will purchase and implement a commercial off-the-shelf (COTS) solution(s) which will address records and retention management, categorization (metadata), and searchability (legal hold and eDiscovery capabilities). BPA is engaged in a multi-year plan called IGLM (Information Governance and Lifecycle Management) to improve the way the information assets are managed. IGLM is comprised of three projects: Phase 1) Communications / e-mail – completed; Phase 2) Unstructured Data Management (UDM); and Phase 3) Structured Data Management (SDM). This investment covers the last two projects, UDM and SDM; the UDM project is in process and the SDM project will be defined and follow UDM.

OP_CABRptText1

Why is this investment needed?

By making this investment, BPA will ensure the Agency has the ability to comply with Federal mandates including the Federal Records Act, Federal Rules of Civil Procedure (for preserving and producing electronically stored information), OMB 12-18 Directive on Managing Government Records, and OMB 13-13 Directive on Managing Information as an Asset.

OMB M-12-18 requires that Federal agencies retain and manage electronic records (information assets) in an appropriate electronic system (or systems) that supports records management and litigation requirements. This directive requires that this capability be implemented by 2016.

What assumptions are behind the investment need?

OP_CABRptText2

BPA's objective is to fully comply with legal and regulatory directives within the timeframes outlined by directives. It is also assumed that the current, manual state of managing and accessing agency information assets does not comply with those directives and requirements. Current manual processes will be replaced with updated business processes which will utilize the strengths of the system(s) selected.

OP_CABRptText3

What actions would we take if this investment were not made?

BPA would continue with the status quo of manually managing and accessing unstructured and structured data.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

The status quo of continuing the manual state of managing and accessing agency information assets - including, in some cases, the lack of ability to produce data artifacts - was considered. It is not recommended because it: 1) does not provide compliance; and 2) exposes BPA to litigation, audit, and sanctions risk, and (3) requires excessive labor hours to implement. Software as a Service (SaaS) and Commercial Off the Shelf (COTS) solutions were considered. SaaS was rejected due to data constraints. COTS was selected as the best alternative for BPA.

OP_CABRptText5

Who would benefit from this investment?

All BPA organizations; BPA customers by reduced BPA legal risks and costs; Executive branch agencies, including DOE, DOJ, and OMB.

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Dec-13	Jul-18	Sep-18	Sep-19	$8,555	$9,505	$11,406	$1,300	$6,558	$1,856	$1,602	$0	$0	$11,315	16%	5	7	10

What drives the investment costs to be low or high?

Phase 2 UDM project cost would be reduced if implementation is less complex than expected, resulting in reduced BPA labor hours and costs. Phase 3 SDM project cost would be reduced if a module from the UDM vendor is acceptable to manage structured data.

Phase 2 UDM project cost would increase if implementation is more complex than expected, resulting in increased BPA labor hours and costs. Phase 3 SDM project cost would increase if a separate solution is required to manage structured data.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$651	$651
Present value	$0	$3,823	$3,823

Invenergy’s Willow Creek Phase 1 Fiber Installation - G0255
Classification: Compliance
Sponsoring Asset Category: Transmission

What is the proposed investment?

The proposed investment is fiber optic cable from BPA’s Boardman Substation to a splice point near Willow Creek’s tap on BPA’s line. From that point, the customer owns fiber to their collector station. A second customer-owned fiber goes from the collector station to a second splice point about 3 miles away from the first one. BPA will add fiber from the second splice point to Slatt. A total of about 24 miles of new fiber optic cable is required. After the new fiber is in place some circuits will need to be reconfigured to transfer off the Windwave fiber.

OP_CABRptText1

Why is this investment needed?

This investment is needed to finish out the plan of service for Willow Creek Wind Project. This work was identified in the planning stage, but was delayed until BPA finished adding a SONET node at Boardman Substation and upgrading the Ross fiber ring. Now that the SONET node is at Boardman and BPA has upgraded the fiber between Boardman and Slatt, this fiber project is required to finish the communication ring needed to make the RAS at Willow Creek fully WECC-compliant. When the RAS was initially presented to the WECC RAS committee, it was approved provisionally, provided that BPA eventually came back and finished the fiber ring. BPA is temporarily using leased fiber (from Windwave) to complete the communications ring for the RAS. However, WECC rules discourage the use

What assumptions are behind the investment need?

OP_CABRptText2

The assumption is that the communication ring should be completed to make the RAS at Willow Creek fully WECC compliant.

OP_CABRptText3

What actions would be taken if this investment were not made?

There are no alternatives to new fiber. There are too many wind turbines in the area to use radio, which has been investigated. In the short term, BPA could continue to lease fiber, but still runs the risk of being called non-compliant with the RAS because the lease was not supposed to be the long-term solution.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

The alternative would be continue to lease, but this is not a long term solution to meet WECC requirements.

OP_CABRptText5

Who would benefit from this investment?

Communication Design (TEC); Field (Tri-cities District); CMO; owner of wind project

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Oct-16	Jul-18	Sep-18	Sep-19	$2,530	$3,080	$3,880	$0	$0	$382	$3,437	$0	$0	$3,819	0%	25	30	40

What drives the investment costs to be low or high?

Costs could be higher or lower than expected depending on material and labor costs, as well as if the work is contracted out or not.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$1	$1
Present value:	$0	$13	$13

Invenergy's Willow Creek Phase 1 Fiber Installation - G0255

Lower Monumnetal Powerhouse 2nd 500 kV Generation Tie Line - L0368
Classification: Compliance
Sponsoring Asset Category: Transmission

What is the proposed investment?

This project will interconnect a second powerhouse line from USACE's Lower Monumental Powerhouse to BPA-TS's Lower Monumental Substation at 500 kV. A new line position would be added at the north of the substation in Bay 9, similar to the first line, but with a breaker added for operational flexibily. One new 500 kV breaker, two 500 kV disconnect switches, surge arresters and potential transformers will be installed, along with the standard line relaying and protection. Approximately 1 mile of new 500 kV overhead transmission line is required. The new transmission line will include fiber optic cable and overhead ground wire. For reliabilty, BPA Planning has asked that USACE not spilt the bus at the powerhouse with a 500 kV breaker because the of high flows from Little Goose; it is preferred that the generation is split between the two 500 kV lines when in normal operation.

OP_CABRptText1

Why is this investment needed?

This investment is intended to improve O&M flexibility for United States Army Corp of Engineer's (USACE's) Lower Monumental Powerhouse (LMPH) and the BPA owned Lower Monumental Powerhouse-Lower Monumental Substation No 1 500 kV line (LMPH-LOMO-1). It also offers a redundant connection between USACE's Lower Monumental Powerhouse and BPA's Transmission System. In addition, this project will mitigate the risk of a 25% annual loss of the Snake River returned Sockeye salmon run.

What assumptions are behind the investment need?

OP_CABRptText2

The assumption is that additional O&M flexibility is needed at USACE's LMPH and LMPH-LOMO-1 in order to avoid generation outages that have risk to fish with increased temperature and dissolved oxygen, and have risk of causing damage to the USACE generators, which are funded by BPA Power Services.

OP_CABRptText3

What actions would be taken if this investment were not made?

BPA-T would continue to maintain the existing BPA owned Lower Monumental Powerhouse – Lower Monumental Substation No. 1 500 kV line (LMPH-LOMO-1) and USACE would do the same work for their owned facilities at the Powerhouse. Future work that would require a generation outage (speed/no load operation) has a risk to fish with increased temperature and dissolved oxygen, and a risk of causing damage to the USACE generators which are funded by BPA Power Services. BPA-T also has a future need to replace the conductor on the existing line and when that project is under construction it would cause an extended outage, as there is no existing redundancy. In the past, at Lower Granite Dam which is a duplicate of this Dam, an extended outage on the transmission line for

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

One other alternative was considered was extension of the Lower Monumental Substation to the south. That would involve adding two breakers, five disconnect switches, and would involve significant site work. This alternative is not recommended due to the cost.

OP_CABRptText5

Who would benefit from this investment?

TEP, TPC, KEC, TSE, TES, USACE Walla Walla, PGF, TLM

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Oct-16	Sep-18	Sep-19	Sep-22	$11,360	$13,900	$19,005	$0	$0	$2,585	$6,894	$7,756	$0	$17,236	0%	40	50	70

What drives the investment costs to be low or high?

The biggest factors that drive costs low or high are the amount of site work needed, the environmental work needed, and which alternative is constructed.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$1	$1
Present value:	$0	$49	$49

Benefits of the Investment

Benefit name	Benefit description	% of Total
avoided line outage (unplanned)	Unplanned generation outage due to line failure. This project would add a second line to Powerhouse and add another level of redundancy that given an unplanned line outage, that generation would not be interrupted.	4%
avoided planned generation outages	avoided planned generation outages due to line reconductor and roof replacement in 2020	14%
Dolby testing	Avoided planned outages	24%
Unit 5 Asset Life	Unit 5 operates for approximately 1-week per year in station service mode for transformer doble testing. This operating condition causes cavitation damage, but cavitation damage also occurs during normal operations.	0.0%
Returning Salmon Benefit	Planned generation outages in July could result in the loss of up to 25% of the returning Sockeye salmon run (25% of 2000). The speed at which stocks are replenished to natural levels is inhibited unless a second line to powerhouse can be added.	58%
		0%
		0%

Lower Monumnetal Powerhouse 2nd 500 kV Generation Tie Line - L0368

OP_CABRptTable

Lower Valley Upgrade
Classification: Compliance
Sponsoring Asset Category: Transmission

What is the proposed investment?

The investment would be a new 138/115kV Hooper Springs Substation connecting to PacifiCorp's new Three Mile Knoll 345/13kV Substation. There would also be a new ~35-mile double circuit 115kV line from Hooper Springs to the Lower Valley System.

OP_CABRptText1

Why is this investment needed?

This project is needed to avoid the risk of a NERC violation and provide reliability for current and future load levels. It will provide a second source into the Lower Valley Area transmission system, which will support the southern portion of the system during the critical contingency, as well as other contingencies interrupting the transmission path from Goshen Substation.

What assumptions are behind the investment need?

OP_CABRptText2

BPA Transmission Planning has determined that the single contingency loss of the Palisades-Snake River 115kV line could cause low voltages and thermal overloads in the LVE/FREC load area if the outage occurred during heavy winter peak load conditions. This would be a violation of NERC/WECC Reliability Standard TPL-002-0b which stipulates that BPA must keep "both thermal and voltage limits within applicable rating."

OP_CABRptText3

What actions would be taken if this investment were not made?

Thermal overloads could occur on Lower Valley's Teton-Wilson 115kV line. Opening the line to protect it from the overload could cause load loss to the southern portion the Lower Valley System, leaving many constituents without power during winter temperatures as low as -50º F.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

A non-wires alternative to add gas generation near Jackson was considered and discarded due to uncertainty regarding whether it would be feasible to get the necessary permits for the project so close to sensitive areas such as Teton and Yellowstone National Parks as well as potential problems with getting fuel for the generation to the area during the critical winter months.

OP_CABRptText5

Who would benefit from this investment?

Lower Valley Energy, Idaho Falls Region

Lower Valley Upgrade

OP_CABRptText6

Timing and Costs of the Investment
(2017 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2017	2017	2018	2019	2020	Post 2020	Total	% of Investment that is expense	Low	Base	High
Jun-15	Dec-18	Mar-19	Jun-20	$60,327	$66,015	$91,025	$19,042	$22,001	$34,224	$6,519	$0	$0	$81,787	0%	50	60	70

What drives the investment costs to be low or high?

For Low: Assume Southern (shortest) route and all costs, particularly land rights, are managed to those currently predicted.

For High: Assume Northern (longest) route a number of land rights cost significantly more than currently predicted.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$216	$220	$5
Present value:	$9,523	$9,738	$215

Lower Valley Upgrade

Monroe 500kV Line Retermination
Classification: Compliance
Sponsoring Asset Category: Transmission

What is the proposed investment?

This project reterminates two 500 kV lines at Monroe substation. The Monroe-Chief Joe 500 kV line will be reterminated from Bay 4 into a new line terminal in Bay 5. The Monroe –Custer #2 line will be reterminated from Bay 3 into Bay 4. Add new spell out: LLL on the Monroe-Custer #2 line in Bay 4. Add new line protection relay to relay transfer trip on the Monroe-Custer #2 in Bay 4. Re-wire the existing differential relays in Bay 3 to pick up PCB 4526.

OP_CABRptText1

Why is this investment needed?

The Monroe line retermination project will eliminate a severe N-2 outage (Breaker Failure PCB4526) which results in loss of two 500kV lines at Monroe (Custer-Monroe#2 and Monroe-Echolake). This is the most severe thermal and voltage stability Main Grid outage for the PSANI area. By reterminating the Custer #2 and Chief Joe lines, there will no longer be a credible common mode failure that would result in loss of two lines at Monroe 500kV station. Eliminating BKF 4526 will increase Northern Intertie Total Transfer Capability by at least 50MW, and provide more reliable load service to the Puget Sound Area. The project will also provide increased operational flexibility when taking maintenance outages for the breakers at Monroe, Custer and Echo Lake substations.

What assumptions are behind the investment need?

OP_CABRptText2

Assumes this project will increase the capacity of the Northern Intertie by a minimum of 50 MW and that there is demand to fill this extra capacity. Other assumptions: no land needs to be acquired, no expansion of yard will be necessary, no relocation of structures will be needed, and expansion of control house will not be needed. These added assumptions have nothing to do with the "Investment Need".

OP_CABRptText3

What actions would be taken if this investment were not made?

Do nothing and live within existing system operating limits. This will reduce Operations and Maintenance flexibility in the Puget Sound and Northern Intertie area.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

Only the do nothing alternative was considered.

OP_CABRptText5

Who would benefit from this investment?

Technical Operations and Substation Maintenance would benefit from the increased reliability. The capacity of the Northern Intertie would be increased, which would benefit transmission customers and add to BPA transmission revenue.

Monroe 500kV Line Retermination

OP_CABRptText6

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete						Pre-					Post		% of Investment			
Start	Early	Base	Late	Low	Base	High	2016	2016	2017	2018	2019	2019	Total	that is expense	Low	Base	High
Apr-16	Sep-18	Feb-19	Sep-19	$5,213	$6,779	$7,288	$0	$84	$4,623	$3,278	$420	$0	$8,406	0%	30	40	50

What drives the investment costs to be low or high?

Costs will be low if Monroe and customer relays can be re-used, brush clearing costs are minimal, station service does not need to be updated, retermination costs are relatively low, a new trenway is not needed, and costs for landings to access are relatively low. In-house labor is used. Costs will be high if the relays require enhancements, significant brush clearing is required, station service needs to be updated, retermination costs are relatively high, a new trenway is required, and costs for landings to access are relatively high. May need a new trenway if existing trenway is full ($100k). Contractor is used to perform most of the work.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$45	$51	$7
Present value:	$1,045	$1,200	$154

Monroe 500kV Line Retermination

Northern Wasco Network Load Expansion 3 - L0380
Classification: Compliance
Sponsoring Asset Category: Transmission

What is the proposed investment?

In order to interconnect 300MW of load at Chenoweth substation, facility upgrades will be required including an upgrade of BPA's Big Eddy – Chenoweth #1 line from 115kV operation to 230kV operation, construction of a new 230kV substation yard at the point of interconnection, and either a new 230kV ring bus substation just North of Big Eddy Substation or extensive line rerouting at Big Eddy substation. The upgraded Big Eddy – Chenoweth #1 and Big Eddy – Chenoweth #2 lines will be looped into the new substation at L0380. It is assumed the Point of Interconnection will be a new 230kV bus owned and constructed by BPA, and that load service transformers and low-side switching equipment will be constructed and owned by N. Wasco.

OP_CABRptText1

Why is this investment needed?

Northern Wasco PUD (N. Wasco) has requested an additional 300 MW of load growth in the Dalles district and it was entered into the BPA Transmission Interconnection queue as request L0380. This new load will be served out of BPA's Chenoweth substation to support N. Wasco's customer's new data center complex. N. Wasco's customer already has an existing presence in the area with service from N. Wasco's Discovery substation, which is tapped off BPA's Chenoweth-The Dalles 115kV line. This will be a Project Funded In Advance (PFIA) by the customer and the customer will receive transmission credits in return.

What assumptions are behind the investment need?

OP_CABRptText2

Northern Wasco PUD (N. Wasco) has requested an additional 300 MW of load growth in the Dalles district and it was entered into the BPA Transmission Interconnection queue as request L0380. This new load will be served out of BPA's Chenoweth substation to support N. Wasco's customer's new data center complex. This investement is designated PFIA and will be funded up front by the customer.

OP_CABRptText3

What actions would be taken if this investment were not made?

Any additional load would be restricted by the existing transmission capacity from Big Eddy to Chenoweth substation. Without being able to realize the full potential of the data center expansion, the N. Wasco customer may decide to not pursue their proposed expansion.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

Do nothing option would require BPA to reject N. Wasco's request for a new Line Load Interconnection (L0380) and BPA would not be meeting its OATT obligation therefore the customer may take legal action against BPA. The capacity at Chenoweth would not be increased and the customer may elect to not pursue future growth in the area.

OP_CABRptText5

Who would benefit from this investment?

Internal Groups
TPP, TFD, TEC, TEL, TEP, TER, TES, TSE, PSS.

External Groups

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Oct-16	Aug-18	Sep-18	Sep-19	$16,600	$20,900	$24,300	$0	$0	$12,958	$12,958	$0	$0	$25,916	0%	40	50	70

What drives the investment costs to be low or high?

It is assumed the Point of Interconnection will be a new 230kV bus owned and constructed by BPA, and that load service transformers and low-side switching equipment will be constructed and owned by N. Wasco. Cost could be low if there is no need for new 230kV ring, replace with 230kV terminal at Big Eddy and reterminate Big Eddy_Chenoweth # 1. Cost could be high if there is additional cost to build Big Eddy-Chenoweth #3, LT115SCPAR, $3.16M

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$4	$4
Present value:	$0	$140	$140

Northern Wasco Network Load Expansion 3 - L0380

PGE’s Blue Lake – Troutdale #2 Line Interconnection - L0365
Classification: Compliance
Sponsoring Asset Category: Transmission

What is the proposed investment?

PGE would build a second 230 kV line from their Blue Lake Substation to BPA’s Troutdale Substation. This would require BPA to double circuit the North Bonneville – Troutdale #1 and #2 lines (about .5 miles) and move the North Bonneville – Troutdale #1 line over one bay to make room for the Blue Lake #2 line. BPA would install a new bay position, including breaker and disconnect switches for the line move. Interchange metering would be required on the Blue Lake #2 line. In order to ensure proper clearances when PGE’s new line is built there may be a need, due to all the line crossings, to configure up to three line structures differently (to be identified in the design phase).

OP_CABRptText1

Why is this investment needed?

PGE needs another source line into the Portland area in order to serve load growth. Their studies have indicated that they could have transmission constraints as soon as 2017 during peak summer loads if this line built isn't built.

What assumptions are behind the investment need?

OP_CABRptText2

The assumption is that PGE needs BPA in order to serve load growth, and that this is their preferred plan of service

OP_CABRptText3

What actions would be taken if this investment were not made?

This would be PGE’s responsibility; possibly including load-shedding schemes.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

PGE has other Transmission expansion options, but they are much more expensive and more significant build options.

OP_CABRptText5

Who would benefit from this investment?

TESD, TELD, TF, TEP, TOT

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Oct-16	Jun-18	Jun-18	Jun-19	$2,400	$2,500	$4,800	$0	$0	$713	$2,387	$0	$0	$3,100	0%	35	40	50

What drives the investment costs to be low or high?

The feasibility of getting the line into Troutdale substation affects the cost. Based on requirements for the acceptable distance between lines, custom structures may be required.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$0	$0
Present value:	$0	$0	$0

PGE's Blue Lake – Troutdale #2 Line Interconnection - L0365

FY15 - FY17 PMUs
Classification: Compliance
Sponsoring Asset Category: Transmission

What is the proposed investment?

This project installs 27 Phasor Measurement Units (PMU) at 13 sites in 3 phases over 4 years. Each phase is composed of 1 year of design and 1 year of construction. The equipment being installed includes control and data PMUs, routers and channel units. Some of the PMUs would be new installations for areas not yet monitored and others would replace old PMUs.

The Synchrophasor Project approved by the CAB has deployed most of the PMUs planned by the Western Interconnection Synchrophasor Project (WISP), but critical substations had to be bypassed due to scheduling and other issues. This project is a follow-up to the Synchrophasor Project to complete the installation of PMUs at those sites.

OP_CABRptText1

Why is this investment needed?

The PMU project provides wide area monitoring across the WECC system to provide better situational awareness and improve transmission operation and increase transmission utilization. Other benefits include the avoidance of large scale outages.

Transmission providers such as BPA are required to verify actual performance of generators connected to the system and validate simulation models to ensure adequate voltage performance is being

What assumptions are behind the investment need?

OP_CABRptText2

The costs are based on our past experience with installing PMUs. Most of the issues with installing the PMUs have been resolved. If there are still show stoppers at a substation, we will chose to do another substation in it place.

OP_CABRptText3

What actions would be taken if this investment were not made?

PMUs would stop being deployed upon completion of the Synchrophasor project was approved a couple of years ago by the CAB. Data would be reviewed to see if the existing PMUs provide an adequate information to comply with NERC standard PRC-002. If as expected they would not provide adequate information, a corrective action plan work need to be created and a new investment proposal submitted.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

Stop deploying PMUs after FY14 and review the data to see if the existing PMUs provide an adequate system picture to comply with PRC-002.

OP_CABRptText5

Who would benefit from this investment?

Transmission customers , through avoided outages and outage costs, increased BPAT revenue through fuller, more optimal system use, and avoided regulatory sanctions from noncompliance.

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Oct-15	Jul-18	Sep-18	Dec-18	$6,909	$6,909	$8,316	$0	$3,941	$4,626	$0	$0	$0	$8,567	0%	15	20	25

What drives the investment costs to be low or high?

If no extra cabling and no battery replacements are required, then costs will come in low. If extra cabling and battery replacements are required beyond expectations, then cost will be high. If there are multiple control houses involved , costs will also likely be higher than expected.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$18	$21	$3
Present value:	$250	$296	$45

FY15 - FY17 PMUs

Pisces Web Project
Classification: Compliance
Sponsoring Asset Category: IT

What is the proposed investment?

Replace the current Pisces desktop application (Click-once, .NET software) by consolidating it with BPA's fish and wildlife portfolio management system, Taurus, a robust, up-to-date technology that is accessible by a web browser. The combined system will improve usability and utility, reduce redundancy and support costs, and comply with governmental accessibility standards. The combined system will be platform agnostiic, thereby increasing external user adaptability and allowing a variety of access points such as smart phones and PC's with different web browsers. The combined system will be scalable, accounting for new functionality requirements to increase productivity as the F&W Program evolves.

OP_CABRptText1

Why is this investment needed?

Pisces is the critical system required by a National Environmental Policy Act Record of Decision under the Fish and Widlife Implementation Plan Environrmental Impact Statement (EIS). The system serves as the retainer of records to document environmental compliance for BPA-funded fish and widlife actions and to manage 900+ contracts annually. It facilitates collaboration with partners and provides reporting to communities of the Columbia River Basin. With the current technology, usability and process flows are poor due to design, architectural and technological constraints. The technology is no longer compatible with newer user platforms and this trend is expected to worsen. BPA's transition to myPC has caused even more incompatibility and system support challenges. If replacement does not occur, increased contract management costs, decreased efficiencies, reduced satisfaction of partners, and a long-term inability to support the evolving needs of the F&W program will result. Further, the ability to demonstrate compliance will be put at significant risk.

What assumptions are behind the investment need?

OP_CABRptText2

With the current technology, design, architectural and technological constraints will increasingly add to support and enhancement costs and user inefficiencies and dissatisfaction. The system needs of the Environment Fish & Wildlife (EF&W) program will continue to evolve. Integration with MyPC will be a continuing issue. Criticism among external users will grow. With the proposed project, Sitka will continue to provide the quality of expertise and responsive service that it provides for Taurus today.

OP_CABRptText3

What actions would we take if this investment were not made?

In the absence of a system overhaul, the EF&W organization will incur increasing contract management costs, decreased efficiencies, reduced satisfaction of partners, and a system that does not support the needs of an evolving Fish and Wildlife (F&W) Program. The F&W Program would take on the risk with that the system will become incompatible and obsolete to support core functionality. Piecemeal changes would continue to be made to the Pisces Desktop application. Additional staff would be hired to maintain the current application, and the application would need to be put on new hardware as the current hardware was purchased in 2007 and is at end of life.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

Status quo: rejected because costs to enhance and maintain the Pisces Desktop application will continue to increase while its accessibility and utility will continue to decrease. The application and its hardware are obsolete and insufficient to meet user and BPA program management needs, and there's a risk to compliance.

Build another stand-alone application to support the functions now supported by the Pisces Desktop application. Rejected because it would clearly be higher cost to develop, enhance and maintain over time; its usability and integration with Taurus would be a continuing challenge; and development risks would be greater than the preferred alternative.

OP_CABRptText5

Who would benefit from this investment?

BPA EF&W Project Managers / COTR's; BPA Environmental Compliance Reviewers; External Contractors; External EF&W entities such as NOAA, NW Power Council, etc.

Timing and Costs of the Investment

(2016 dollars in thousands)

(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Nov-13	Dec-16	Mar-17	Jun-17	$3,486	$4,357	$5,228	$1,660	$1,962	$1,077	$0	$0	$0	$4,699	7%	5	8	11

What drives the investment costs to be low or high?

Low: Lower labor hours and lower contract service cost for building and testing the new system. The existing Taurus infrastructure can be leveraged with fewer user interaction patterns and minimal new screens that require developer time.

High: Complexity of combining the Pisces and Taurus applications is unexpectedly high, leading to increased developer, project management, and business analyst hours and costs. Availability of resources, whether vendor or BPA, becomes an impediment to timely execution of the project, which adds to project costs.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$693	$220	-$473
Present value	$4,865	$1,544	-$3,320

Pisces Web Project

Reactor Program - FY16
Classification: Compliance
Sponsoring Asset Category: Transmission

What is the proposed investment?

Reactors, PCBs, arrestors, disconnect switches, relays, and SCADA additions at the following substations:

- Lane 180 Mvar @241.5 kV (Impacts Marion and Oregon coast)
- Fairview 40 Mvar @241.5 kV (Oregon coast)
- Fairmont 40 Mvar @241.5 kV (Olympic Peninsula)

Fairview will require a yard expansion.

OP_CABRptText1

Why is this investment needed?

This investment is needed to meet NERC requirements, more specifically, system voltages need to be reduced to established limits to keep generators from pulling out of synchronism and/or the effects of pulling out of synchronism. It also prevents emergency operations of more than 30 minutes in an unstudied state, as prohibited by NERC when operations attempts to reduce voltage by taking transmission lines out of service.

What assumptions are behind the investment need?

OP_CABRptText2

The assumption is that this will be the first of a multi-phase program, where 3-4 reactor additions will be identified to start each fiscal year.

OP_CABRptText3

What actions would be taken if this investment were not made?

If this investment were not made, BPA would need to increase the number and duration of lines taken out of service for voltage control and eventually tell NERC that there is no intention to be in compliance.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

An alternate set of locations (Shelton, Marion, Redmond, and Fairview 115kV) have been identified, but would cost more to have the same impact on the transmission system.
The status quo alternative is to not build, which would cause violations of NERC reliability standards.

OP_CABRptText5

Who would benefit from this investment?

Transmission Field Services (TF), Transmission Planning (TPP), System Operations (TOD, TOT)

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Jan-16	Sep-18	Mar-19	Jun-19	$6,575	$10,579	$16,521	$0	$495	$3,093	$6,540	$2,846	$0	$12,974	5%	43	72	80

What drives the investment costs to be low or high?
There are several factors that drive the variability of the cost. They include:
- Yard Expansion costs; this includes civil work, land acquisition, and security requirements
- Variability in construction labor and material costs
- Whether the work is done in-house by BPA or contracted
- Shipping costs due to federal shipping regulations

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$3	$3
Present value:	$0	$147	$147

Reactor Program - FY16

Anaconda-Dixon-Silver Bow Transformer Replacement and Area Improvements
Classification: Discretionary
Sponsoring Asset Category: Transmission

What is the proposed investment?

The project will retire the existing single-phase transformers at Anaconda Substation and replace them with the existing autotransformer from Dixon Substation. In addition the following upgrades will be made at Anaconda: install a 230 kV breaker on the 230 kV auxiliary bus, a new 69 kV breaker, including bypass disconnect switch, and associated relaying for the breakers and transformer. A new line sectionalizing disconnect switch will be installed inside the Silver Bow fence to provide a point of isolation between BPA's line and the Vigilante Electric (VEC) line. BPA will also replace rod gaps at Anaconda and Silver Bow with surge arrestors to provide adequate lightning protection for BPA's equipment.

OP_CABRptText1

Why is this investment needed?

The primary driver behind the investment is the local reliability of customers. This driven by two circumstances: at Anaconda, the existing transformers exceeds their expected life and are in poor condition (leaking); at Dixon the transformer, while in good condition, is not appropriately configured for its current use, and causes switching outages for the customer whenever BPA does maintenance. The Anaconda-Silver Bow No 1 line is currently operated at 115 kV, but will be operated at 69 kV in the future and will continue to serve VEC's at their 69 kV Silver Bow Point of Delivery (POD). This will negate the need for a majority of the existing equipment at Silver Bow, including 115 kV breaker (B-888) and 69 kV breaker (L-655).

OP_CABRptText2

What assumptions are behind the investment need?

The investment will improve service to customers in the Montana area and avoid the following: outages (possibly black outs), O&M costs and avoided recovery costs.

OP_CABRptText3

What actions would be taken if this investment were not made?

If this investment were not made, the oil leaking transformers would be maintained to keep them running until the end of their asset life and funding becomes available in the sustain program. This may necessitate the need to undertake environmental cleanup due to the PCB content of the leaking transformer oil.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

Two other alternatives were also considered:
1. Only replacing the transformer at Anaconda.
2. Focus on the system upgrades that would most impact the customers in the area (Mission Valley Power and Vigilante Electric), leaving the transformer work to be addressed at the end of their asset life by the sustain program.

OP_CABRptText5

Who would benefit from this investment?

The major benefitter of this investment would be BPA Transmission, as it would reduce transformer losses, reduce maintenance, and improve system reliability. The local customers would also benefit from the increased reliability and the reduction of switching outages.

Anaconda-Dixon-Silver Bow Transformer Replacement and Area Improvements

OP_CABRptText6

Timing and Costs of the Investment

(2016 dollars in thousands)

(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete													% of Investment			
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	that is expense	Low	Base	High
Oct-16	Mar-19	Jun-19	Dec-19	$5,100	$6,815	$7,700	$0	$0	$664	$4,977	$2,780	$0	$8,421	1%	63	75	85

What drives the investment costs to be low or high?

The main driver in the range of costs is the final design, labor, and market price of materials.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$12	$6	-$6
Present value:	$717	$397	-$320

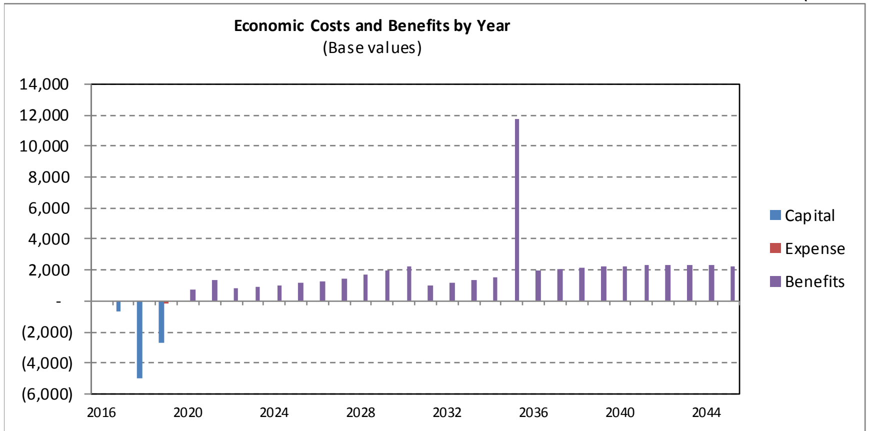
Benefits of the Investment

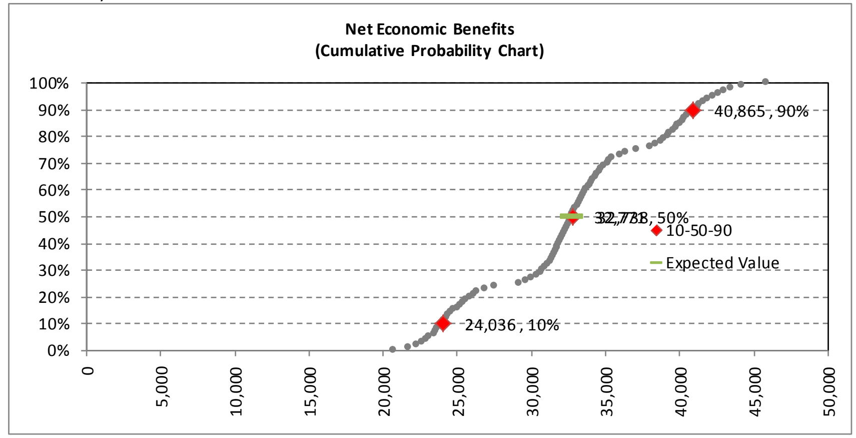
Benefit name	Benefit description	% of Total
Equipment Reliability	The existing Anaconda Transformer bank is leaking oil and has a high risk of terminal failure	66%
Avoided Planned transformer Replacement	If this transformer bank is not replaced within the next few years a planned replacement will be needed in the AC Subs replacement program to assure continued reliabile service	15%
Transformer & Line Losses	High transformer losses due to over-sized units at Anaconda. Silver Bow transformer has losses. Anaconda-Silver Bow line will operate at lower (69kV) voltage increasing losses.	10%
Planned Outage	Planned outages result in customers in the dark at Dixon with current system configuration	6.0%
Reduced Maintenance Costs	Fewer equipment to maintain and newer equipment which requires less maintenance and corrective work. Assess hours of annual maintenance	1%
Value of Retired Assets	Recently installed breakers at Silver Bow can be reused	1%
Unplanned Outage	Reduction in # of equipment will reduce the frequency of unplanned outages and also newer equipment will reduce likelihood of unplanned outage	1%

Anaconda-Dixon-Silver Bow Transformer Replacement and Area Improvements

OP_CABRptTable

Net Economic Benefits and Cash Flows
(2016 dollars in thousands)
(AFUDC not included)

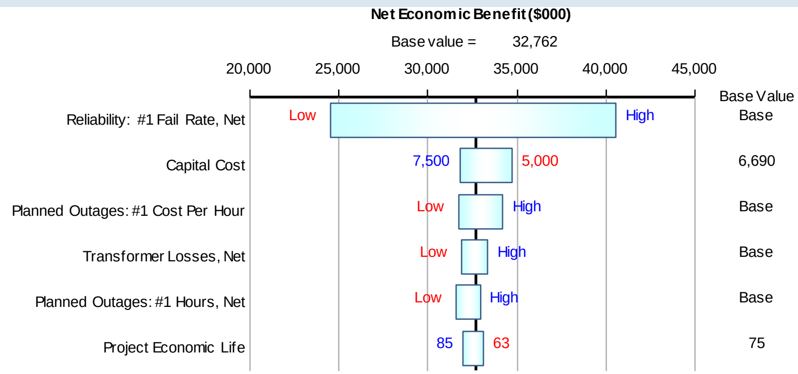


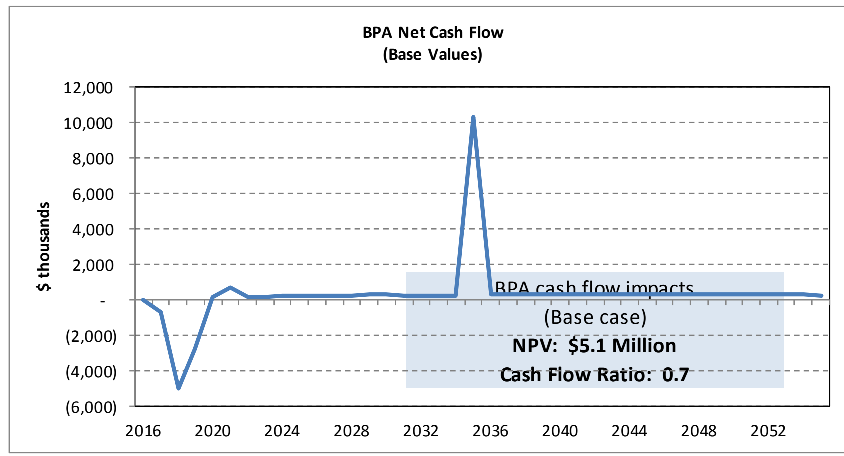


	10%	EV	90%
Investment Cost	5,918	7,632	8,820
Economic Benefits	31,861	40,370	48,661
Net Economic Benefits	24,036	32,738	40,844

Net Economic Benefit Ratio: 4.29

For every dollar invested, there is an net economic return of $4.29 (Expected value)





Additional considerations:

Anaconda-Dixon-Silver Bow Transformer Replacement and Area Improvements OP_CABRptText8

Billing Information System Replacement
Classification: Discretionary
Sponsoring Asset Category: IT

What is the proposed investment?
Acquire, install, and implement a billing information system to replace BPA's current billing information system for wholesale power sales and transmission sales contracts. Alternatively, develop such a system using in-house resources.

BPA generates over $3 Billion in revenue each year. At the heart of maintaining this revenue stream, Customer Support Services (KS organization) supports the agency by issuing 545 bills a month on average. Ensuring BPA has an up-to-date, reliable, and accurate Billing system is essential to producing accurate and timely bills, improving customer satisfaction, and supporting the agency's mission.

OP_CABRptText1

Why is this investment needed?
BPA's customer billing and contracts system (CBC) uses the Lodestar software system. In 2017, Oracle plans to release a new Java-based version of Lodestar. The version of Lodestar that BPA currently uses includes proprietary coding, and a new Lodestar release would require a complete re-write to accommodate the customizations BPA has required. For an additional cost, Oracle will continue to support the current version of Lodestar through 2020, however, Oracles support for the current version would stop then.

What assumptions are behind the investment need?

OP_CABRptText2

Oracle will release a new version of Lodestar that will not include the functionality BPA would need for billing under its wholesale power sales and transmission sales contracts. Oracle will discontinue offering support for the current version of Lodestar after 2020. NOTE: This model includes placeholder cost estimates and has not been fully assessed

OP_CABRptText3

What actions would be taken if this investment were not made?
We would contract with Oracle to provide support to the current version of Lodestar for as long as Oracle is willing.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?
Prior to implementing this project, an alternatives analysis will be conducted to examine the alternatives of status quo, COTS systems, Loadstar v2, or development of an in-house system.

OP_CABRptText5

Who would benefit from this investment?
BPA power sales and transmission sales customers. BPA staff involved with billing and contracts management functions

Billing Information System Replacement

OP_CABRptText6

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Oct-17	Sep-19	Sep-19	Sep-19	$8,002	$9,002	$12,002	$0	$0	$0	$3,601	$5,401	$0	$9,002	0%	3	5	10

What drives the investment costs to be low or high?

Labor hours to define requirements. If a third party solution is acquired, then software acquisition, integration, testing, training, and other implementation costs would drive costs lower or higher. If an in-house solution is decided, then labor hours and costs to design, program, integrate, test, train and otherwise implement the system would drive costs

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$0	$0
Present value:	$0	$0	$0

Billing Information System Replacement

Black Canyon Unit 3
Classification: Discretionary
Sponsoring Asset Category: Federal Hydro

What is the proposed investment?

The Black Canyon hydroelectric plant is owned by the Bureau of Reclamation and located northwest of Boise, Idaho. The dam's primary function is to divert Payette River stream flow for agricultural irrigation. Power generation serves a secondary function. The dam and powerhouse were placed in service in 1924-25. There are two existing generators with capacities of 5.1 MW each. The turbine runners are original equipment, and the electrical equipment was last updated in 1994 and 1995. The units operate reliably, and will continue doing so for the foreseeable future with appropriate maintenance and equipment replacements.
The addition of a new unit would entail a new powerhouse, intake, penstock, structure, and associated equipment. The new unit will provide 12.5 MW of additional generating capacity and is expected to be placed in service in FY 2019

OP_CABRptText1

Why is this investment needed?

BPA is a net importer of power into Idaho. This investment will increase generation at the facility by capturing spill and will also allow for more efficient use of water due to the modern design of the new unit.

What assumptions are behind the investment need?

OP_CABRptText2

Real levelized market price for power based on the most updated price forecast using the 3% real discount rate for expansion projects: $44.90/MWh (Expected Flat.) No capacity adder.
$7.1 million in design costs already expended is sunk, bringing the expected incremental cost of the project to $47.9 million.
Should a third party develop the third unit (a possible scenario if Reclamation does not,) it is assumed that the existing units, 1 & 2, would still be given access to priority water, despite the third unit being more efficient.

OP_CABRptText3

What actions would we take if this investment were not made?

Safety issues and compliance violations in the switchyard necessitated that project be undertaken and design work is underway. Costs of $2 million would be needed to separate out the portions of that project that were specific to the new third unit. $7.1 million in design costs for the new unit would also need to be expensed as there would be no physical asset to tie them to. There is also a possibility that a third party would file a permit to construct the third unit and Reclamation would be required to provide the design to them at no charge.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

The alternative is not to pursue generation at the facility and continue to import power into the region.

OP_CABRptText5

Who would benefit from this investment?

The Bureau of Reclamation; Bonneville Power Administration

Timing and Costs of the Investment

(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete													% of Investment that is expense			
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total		Low	Base	High
Jun-14	Oct-18	Sep-19	Sep-21	$50,000	$55,000	$75,000	$8,751	$6,600	$16,500	$14,900	$8,250	$0	$55,000	0%	40	50	60

What drives the investment costs to be low or high?

Cost overruns due to standard construction uncertainty.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$231	$231
Present value	$0	$6,419	$6,419

Benefits of the investment

Benefit name	Benefit description	% of Total
Power	Incremental generation around 36 GWh/year average.	80%
Carbon Reduction	Carbon Emissions Avoidance from 36GWh/annual	16%
Reduced Costs	$2 million in reduced costs from split-out of Switchyard work.	4%
		0%
		0%
		0%
		0%

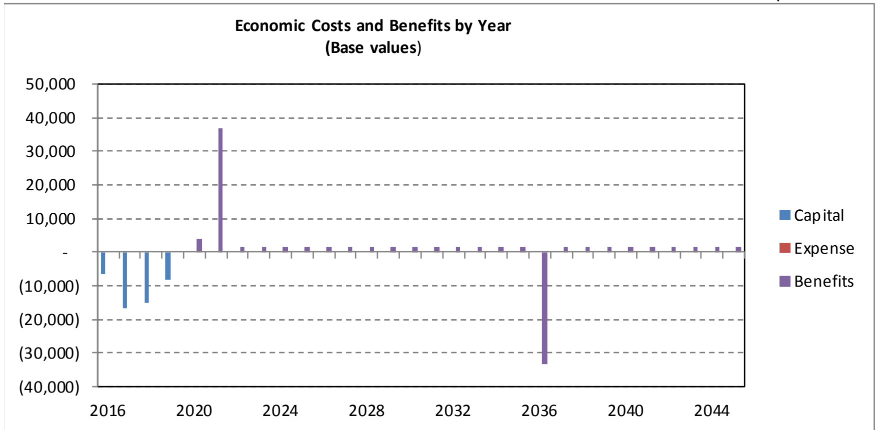
Black Canyon Unit 3

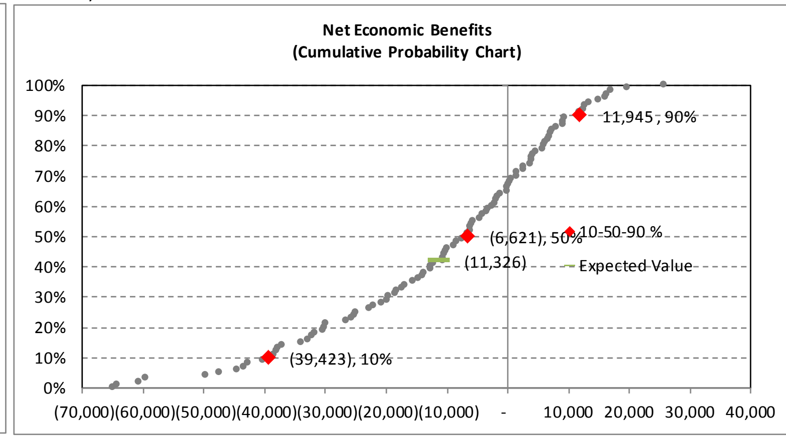
OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)

(AFUDC not included)

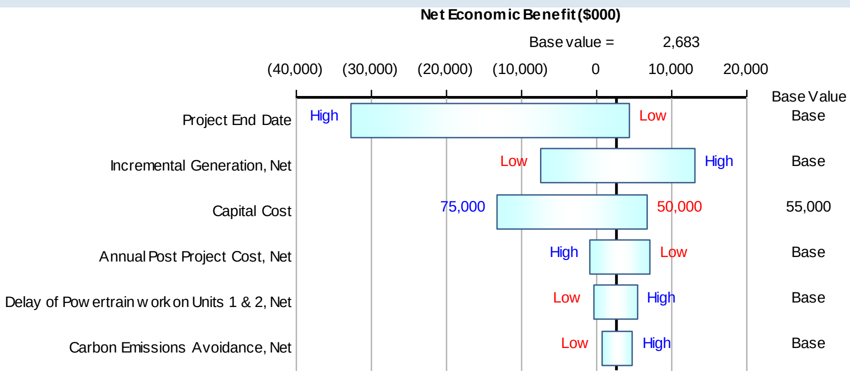


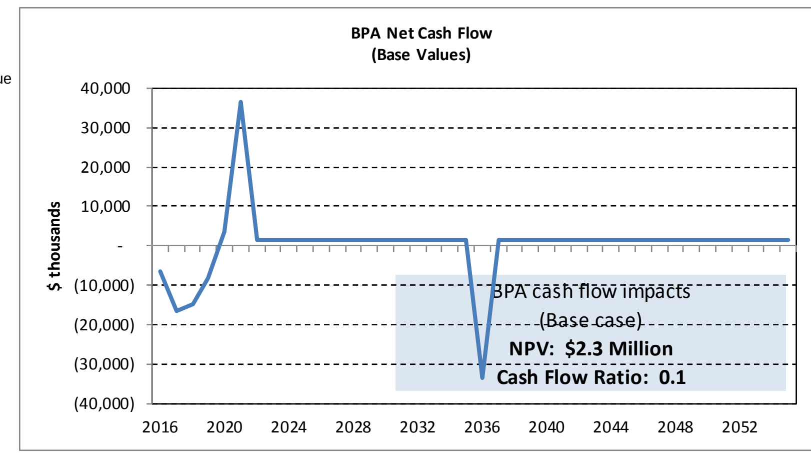


	10%	EV	90%
Investment Cost	40,194	47,868	60,291
Economic Benefits	5,089	36,543	55,842
Net Economic Benefits	(39,423)	(11,326)	11,628

Net Economic Benefit Ratio: -0.24

For every dollar invested there is an economic return of $-0.24 (Expected Value)





Additional considerations:

BPA is a net importer in Idaho; the new resource is non-carbon-emitting; if the project is not pursued, a third party may develop the unit; sunk costs of $7.1 million would be expensed if the project is not pursued and roughly $2 million will be needed to separate out the expansion portion of the switchyard project currently underway.

Black Canyon Unit 3

Carlton O&M Flex
Classification: Discretionary
Sponsoring Asset Category: Transmission

What is the proposed investment?

1. Add 115kV PCB At Carlton substation; breaking the old Forest Grove-McMinnville 115kV line into two separate lines: Carlton-McMinnville #2 and Forest Grove-Carlton
2. Move B- 403 Auto Sect Disc to the Filbert Tap and add SF6 Interrupters to B-403 that will enable loop breaking
3. Add Carlton 115kV Bus Tie PCB addition
4. Add two 230kV PCB’s replacing existing disconnects on the 230kV Bank High Side
5. There are sustain driven investments bundled with this project that are not part of the assessment (Control House Expansion, SPC/PSC)

OP_CABRptText1

Why is this investment needed?

This project is needed to reduce risk and improve reliability at Carlton Steel as well as most of the McMinnville area. The proposed solution will

1. Ensure that Transmission will not lose the entire line and all taps with a fault on this line section
2. Provide better opportunities to replace current manual processes with better relaying, thereby reducing outage time and providing greater operational availability.
3. Unplanned outages causes safety risk for steel worker and expensive clean up.

What assumptions are behind the investment need? OP_CABRptText2

The primary driver behind the proposed investment is the need to reduce risk and improve reliability at Carlton Steel as well as most of the McMinnville area.

OP_CABRptText3

What actions would be taken if this investment were not made?

Without the investment Transmission would be forced to consider either continuing on an "as is" basis.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

An interim solution of installing a bus tie breaker on the 115kV could be implemented as a phased approach at an estimated cost of $1,1M. This will improve the reliability somewhat but Cascade will continue to experience more outages than necessary.

OP_CABRptText5

Who would benefit from this investment?

Making this investment will improve the reliability of all customers served from the Carlton Substation, but Cascade Steel should see a substantial financial benefit based on reductions in both planned and unplanned outages. BPA would also benefit from having fewer unplanned outages and improved operational efficiencies and effectiveness.

Carlton O&M Flex OP_CABRptText6

Timing and Costs of the Investment

(2016 dollars in thousands)

(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Jan-17	Sep-18	Mar-19	Dec-19	$5,200	$6,372	$8,450	$0	$0	$2,370	$4,741	$790	$0	$7,901	0%	40	50	60

What drives the investment costs to be low or high?

Low cost assumes all work done in house and everything goes exactly to plan resulting in completion six months faster than the base case.

High cost assumes 100% of the work is contracted out, which has a higher rate than in-house and there are variations in site conditions that result in additional costs and takes a year longer to complete.

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$20	$29	$9
Present value:	$675	$959	$284

OP_CABRptText7

Benefits of the Investment

Benefit name	Benefit description	% of Total
System reliability	The investment will reduce the number of unplanned outages each year. This will provide significant cost savings to the major industrial user in the area and provide increased flexibility of operations with a small reduction in costs to BPA.	85%
Safety - Clean up	The investment will reduce the number of clean up efforts such as removing cooled metal(jackhammering) and rolling mill clean up during unplanned outages.	15%
		0%
		0.0%
		0%
		0%
		0%

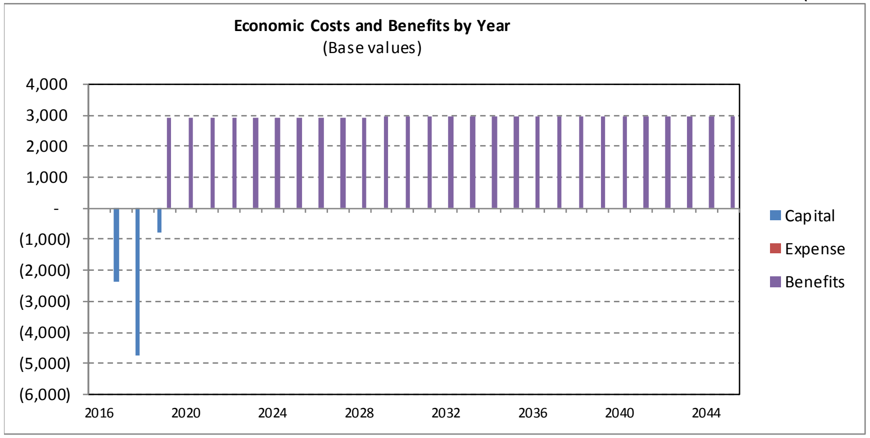
Carlton O&M Flex

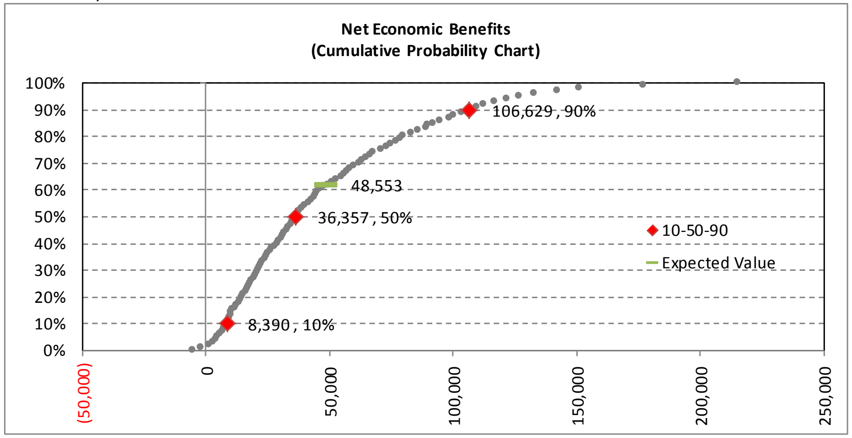
OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)

(AFUDC not included)

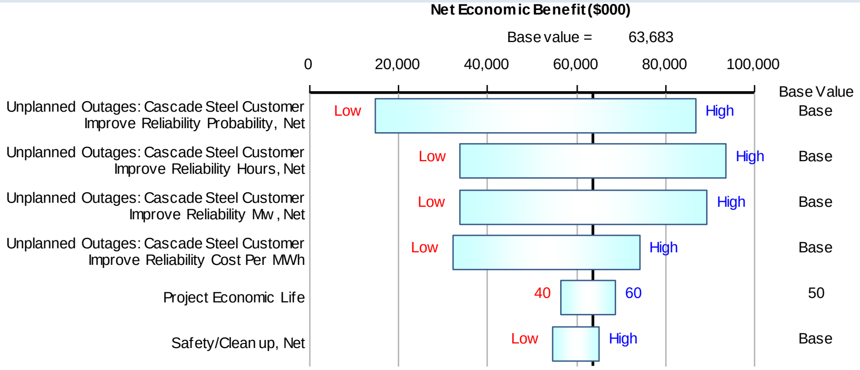


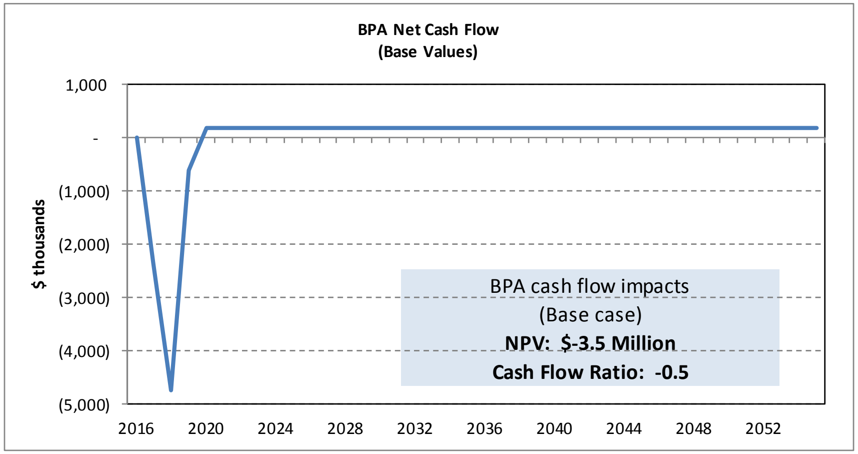


Net Economic Benefit Ratio: 6.29

For every dollar invested, there is an net economic return of $6.29 (Expected value)

	10%	EV	90%
Investment Cost	6,115	7,724	9,937
Economic Benefits	16,279	56,277	113,926
Net Economic Benefits	8,390	48,553	106,263





Additional considerations:

Conkelley Substation Retirement
Classification: Discretionary
Sponsoring Asset Category: Transmission

What is the proposed investment?

Conkelley Substation will be bypassed by joining Columbia Falls – Conkelley and Hungry Horse - Conkelley lines to form Columbia Falls – Hungry Horse #2 and by routing Libby – Conkelley through Flathead substation and tying the Conkelley end of the line into the new Columbia Falls – Hungry Horse #2 line.
This will allow for the retirement of all substation equipment at this location owned by BPA. TPC (Gordon Markley) is processing a sales agreement to sell some of our equipment and our land rights to CFAC.

OP_CABRptText1

Why is this investment needed?

BPA is spending money on operations and maintenance on Conkelley Substation, which no longer serves any load.

What assumptions are behind the investment need?

OP_CABRptText2

Conkelley Substation is located at the Columbia Falls Aluminum Company (CFAC) site in Columbia Falls Montana. The plant ceased operations in 2002 and is now being dismantled. There have been discussions for years about designating the site and the surrounding area as a “Superfund Site”. Those discussions continue today. The substation consists of an East Yard and a West Yard and a separate Capacitor yard near the adjacent tower line ROW. The east yard has a 230kV line to Libby and the west yard has a 230kV line to Hungry Horse and another to Columbia Falls Substation

OP_CABRptText3

What actions would be taken if this investment were not made?

The substation could be left in place, and continued to be operated. Operations and maintenance costs would continue, and equipment would have to be replaced due to its age.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

Status Quo: BPA continues costly operations and maintenance on equipment, and could be liable for potential Superfund cleanup costs. Sale only: BPA continues with sale of portion of substation to CFAC. O&M benefits are not realized, since remaining equipment would still need to be maintained. Phased retirement: The substation is sold/retired in phases. The cost is higher due to extended construction timelines.

OP_CABRptText5

Who would benefit from this investment?

BPA Transmission

Timing and Costs of the Investment

(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Jan-17	Sep-18	Oct-18	Oct-19	$5,080	$6,136	$7,450	$0	$0	$1,902	$5,326	$380	$0	$7,609	0%	51	56	61

What drives the investment costs to be low or high?

Investment costs are largely dependent on the final scope of the project, as well as contract construction costs.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$28	$7	-$21
Present value:	$1,167	$261	-$906

Benefits of the Investment

Benefit name	Benefit description	% of Total
Avoided Sustain Costs	Avoided replacement costs covered by the sustain program	85%
Maintenance Savings	Cost savings from elimination of maintenance costs	8%
Proceeds from Sale	Proceeds from sale of equipment/land to CFAC	6%
Salvage Value	Parts value and scrap value of equipment to be retired	1.0%
		0%
		0%
		0%

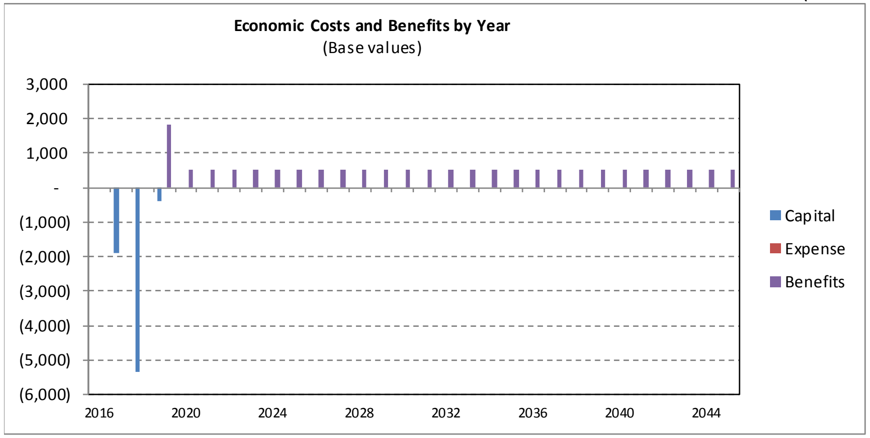
Conkelley Substation Retirement

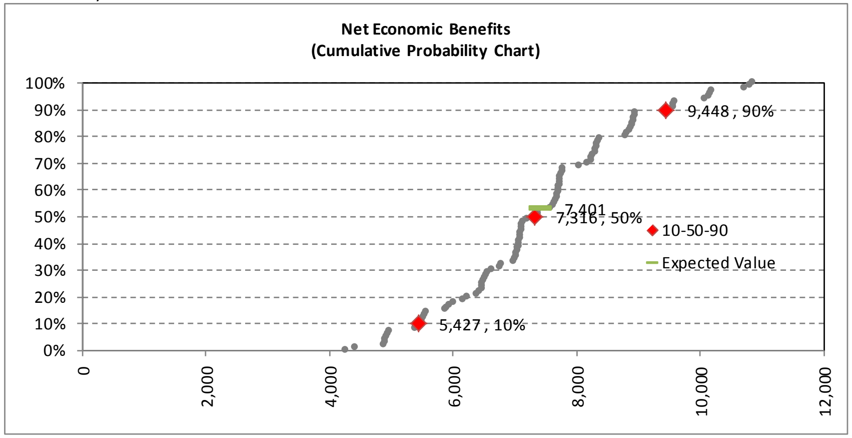
OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)

(AFUDC not included)

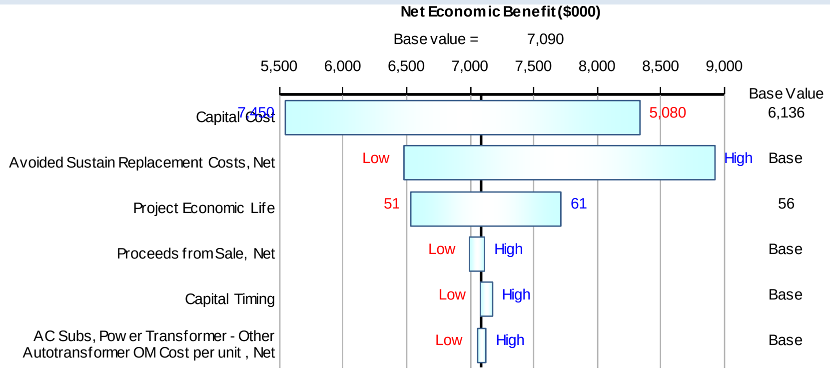


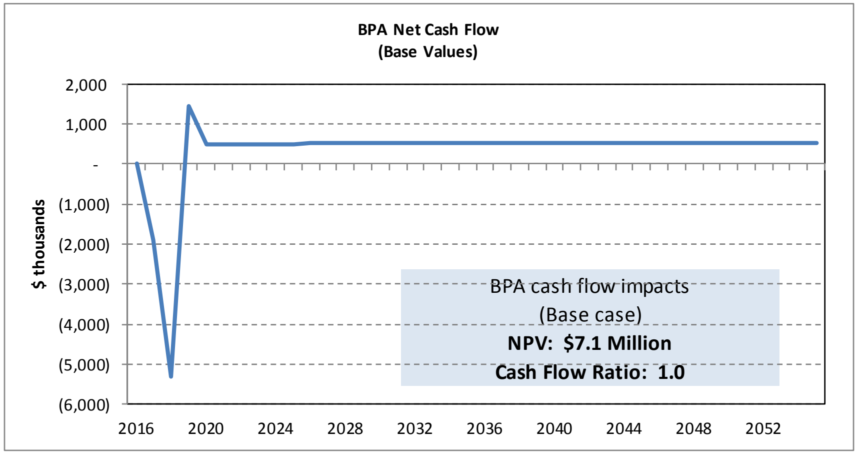


	10%	EV	90%
Investment Cost	5,973	7,272	8,760
Economic Benefits	13,620	14,649	16,155
Net Economic Benefits	5,427	7,401	9,448

Net Economic Benefit Ratio: 1.01

For every dollar invested, there is an net economic return of $1.01 (Expected value)





Additional considerations:

The Columbia Falls - Hungry Horse fiber project must be complete before Conkelley Substation can be retired. BPA can move forward with the equipment sale and begin retiring portions of the substation, but must remain onsite with equipment in order to maintain a communications link. The benefits for reducing BPA's CERCLA/SuperFund liability is unclear at this time, although it appears this investment will have little effect on the probability or magnitude of the liability.

Grand Coulee Units 19-21 Uprate
Classification: Discretionary
Sponsoring Asset Category: Federal Hydro

What is the proposed investment?

Replace turbines in Units 19-21 in the Third Powerhouse at Grand Coulee, taking advantage of upcoming outages and gaining 80 MW of capacity from each unit.

OP_CABRptText1

Why is this investment needed?

Reclamation plans to rewind the generators and perform other rehabilitation and replacement activities on units G19-G21 in the near future as part of the Third PowerPlant overhauls. These units have been in service since the 1970s and are nearing end-of-life. There is potential to uprate these units while the project is underway, and for a relatively minimal incremental investment. At present, the units operate at a maximum of 690MW, although nameplate capacity is only 600MW. Uprating would add 80MW of capacity to each of units G19-G21, for a total addition of 240MW at the plant. Deferring runner replacement now will result in having to take a second costly outage likely within a decade of the completion of the Third Powerhouse overhauls.

OP_CABRptText2

What assumptions are behind the investment need?

Increased generation from spill capture and efficiency gains are valued at BPA Mid-C energy price forecasts.

OP_CABRptText3

What actions would be taken if this investment were not made?

If no investment is made at all, it is possible that deterioration would eventually lead to the units being derated to the nameplate capacity of 600MW. At best, no action in the near term only pushes out the need for investment by a few years. Deferring the project will increase the likelihood of a forced outage in one of the big units at the plant.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

Status Quo: Do Nothing. Continue to operate the units as they have been operated and expect Reclamation to derate the units from 690MW to 600MW. Expect increased maintenance outages and costs, as well as the possibility of forced outages. Next Best Alternative: This entails a capital replacements of the stator windings, cores and frames, shafts, runners, wicket gates and stay vanes. This alternative maintains the current sustained capacity of the units of 690MW. Recommended Alterantive: Uprate to 770MW.

OP_CABRptText5

Who would benefit from this investment?

DOI – Bureau of Reclamation; DOE – Bonneville Power Administration Reclamation

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Oct-14	Apr-24	Apr-27	Oct-28	$122,023	$147,600	$199,540	$753	$915	$783	$1,902	$7,331	$135,916	$147,600	0%	30	50	75

What drives the investment costs to be low or high?
Higher investment costs would primarily result from schedule delays, unfavorable bids and finding equipment in poorer condition than expected. Lower investment costs would be driven by an expedited schedule and favorable bids.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$166	$0	-$166
Present value:	$5,250	$0	-$5,250

Benefits of the investment

Benefit name	Benefit description	% of Total
Increase in generation	Spill capture capability was derived from a historical analysis of spill data at Grand Coulee using data from 1993 through 2013. Uprating Units 19-21 from 690 MW to 770 MW allows for the capability to capture water that is currently spilled during capacity constrained times of the year. The uprates will result in an average of 81.57 GWh of spill capture per year, displacing the need to make an equivalent amount of spot market purchases.	9%
Increase in efficiency	Efficiency benefit was derived from a historical analysis of spill data at Grand Coulee using data from 1993 through 2013. This project will allow for more efficient deployment of units at the plant, resulting in using less water to produce the same amount of power and an incremental gain of 158 GWh/year.	19%
Avoided Future Outage Costs	In addition to the increases in generation and efficiency due to turbine replacement, future costly outages are avoided by taking advantage of the upcoming necessary outages for generator replacement. Benefits encompass avoided lost generation and the costs of unit disassembly and reassembly sometime in the next twenty years.	57%
Avoidance of RBO and BBO	Turbine replacement will improve the reliability of the units. By ensuring that components are replaced on a planned basis, the likelihood of considerably longer outages due to turbine component failure is reduced along with the likelihood of minor but more frequent forced outages.	2%
Avoided Carbon Emissions	Carbon Emissions benefits are tied to the incremental generation associated with completing this project. Incremental generation from increases in efficiency and spill capture will offset spot market energy purchases likely produced from a carbon emitting source.	7%
Renewable Energy Credits	Hydroelectricity attributable to efficiency upgrades is an eligible renewable resource under Oregon's Renewable Portfolio Standard. If an efficiency upgrade is made to a federal hydropower project, only that portion of the electricity generation attributable to "Oregon's Share" may be used to comply with the Oregon RPS. This value is passed along to customers.	6%
		0%

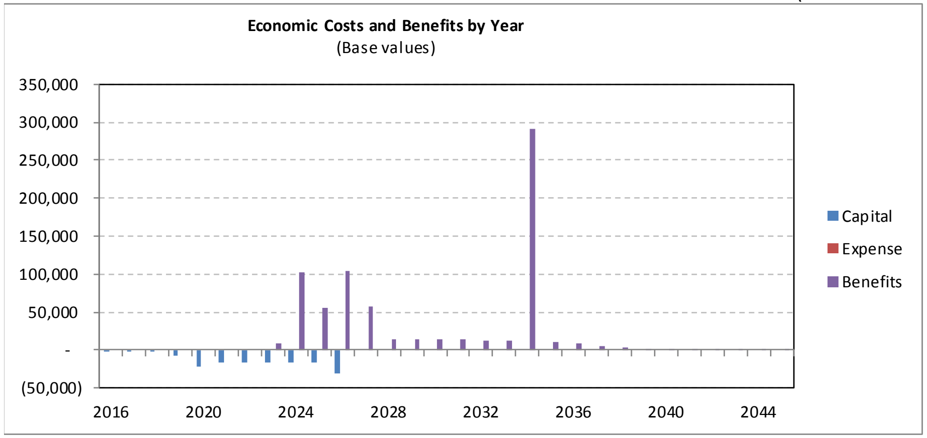
Grand Coulee Units 19-21 Uprate

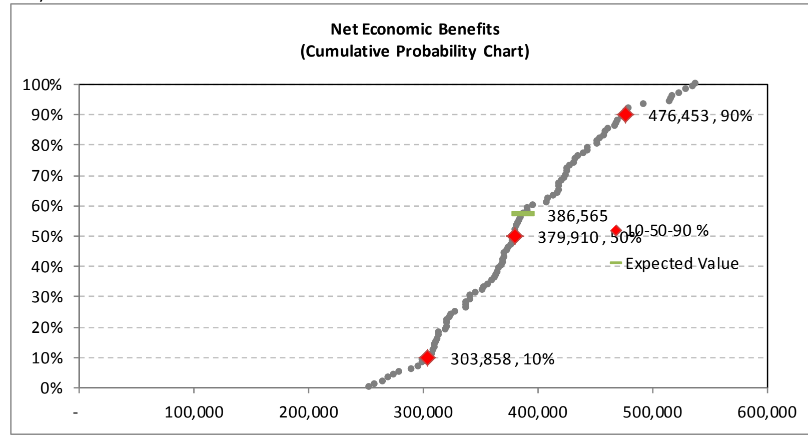
OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)

(AFUDC not included)

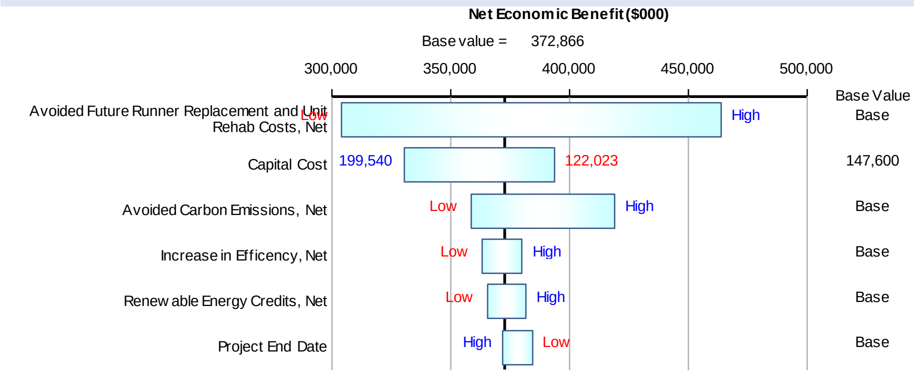


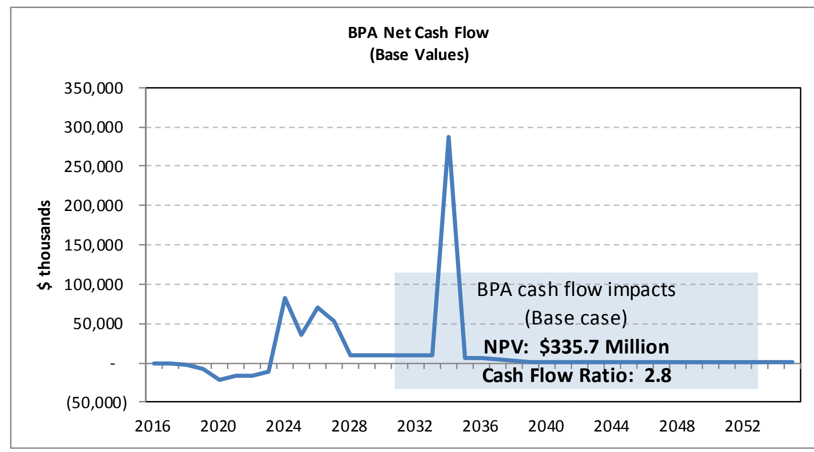


Net Economic Benefit Ratio: 3.06

For every dollar invested there is an net economic return of $3.06 (Expected value)

	10%	EV	90%
Investment Cost	99,434	126,445	163,292
Economic Benefits	423,220	513,010	594,245
Net Economic Benefits	303,858	386,565	473,823





Additional considerations:

Grand Coulee Units 19-21 Uprate

OP_CABRptText8

Grand Coulee LPH-RPH Penstock Stoplogs
Classification: Discretionary
Sponsoring Asset Category: Federal Hydro

What is the proposed investment?

Grand Coulee Dam is seeking to purchase an additional set of Main unit stop logs to support concurrent upgrade activities on multiple units and to reduce the risk of interrupted water management and power generation operations.

OP_CABRptText1

Why is this investment needed?

The spillway of Grand Coulee Dam was built during the original dam construction, which was completed in 1941. The Left and Right Powerplants of the main dam each contain 9 main generating units with 125MW capacity each. These main units are more than 70 years old and will be receiving various upgrades and refurbishments in the coming years. There are 15 of the generators that will be receiving replacement stator windings and associated rotor repairs, and all of the units will be modified with static excitation systems and digital style governor controls. Additional work to be performed during the main unit upgrade outages includes: recoating of the penstocks, replacement of penstock bypass valves, and various modifications to instrumentation and monitoring systems. Penstock stoplogs are required for many of these repairs. The estimated timeframe for the main unit upgrade work is between 7 and 11 years, during which time, there could be extended periods where the dam's single set of stoplogs are installed, leaving no immediate availability of a stoplog set should a need arise. If this

OP_CABRptText2

What assumptions are behind the investment need?

It is assumed that the previously approved Grand Coulee Left and Right Powerhouse work will proceed as planned. It is also assumed that if a second set of stoplogs is not purchased, those overhauls will be extended for an additional five years.

OP_CABRptText3

What actions would be taken if this investment were not made?

If this investment is not made, all G1-18 Modernization efforts will be extended an addition 5-yrs as only one unit at a time will be able to be modernized.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

Schedule extension of five years.

OP_CABRptText5

Who would benefit from this investment?

Bureau of Reclamation

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Dec-15	Jul-18	Oct-18	Feb-19	$7,500	$9,000	$12,000	$0	$450	$450	$6,300	$1,800	$0	$9,000	0%	30	45	60

What drives the investment costs to be low or high?
The bidding process.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	-$982	-$982
Present value:	$0	-$40,449	-$40,449

Benefits of the investment

Benefit name	Benefit description	% of Total
Schedule Delay Avoidance	The G1-G18 project schedule will be extended for an additional five years if only one set of stoplogs is available. Staff and contractors will need to remain on site and engaged in these various projects during that time. The present value incremental cost of keeping contractors around for that long is estimated to be $7.5 million.	15%
Unit reliability (risk reduction)	Extending the schedule by five years (the without investment scenario) actually pushes out work on five of the generating units by 10 years. That additional time increases lost generation risk by $44.2 million PV.	86%
		0%
		0%
		0%
		0%
		0%

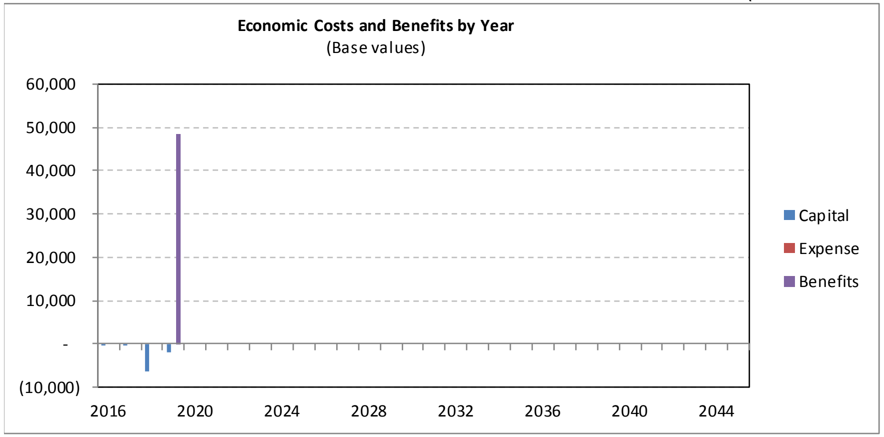
Grand Coulee LPH-RPH Penstock Stoplogs

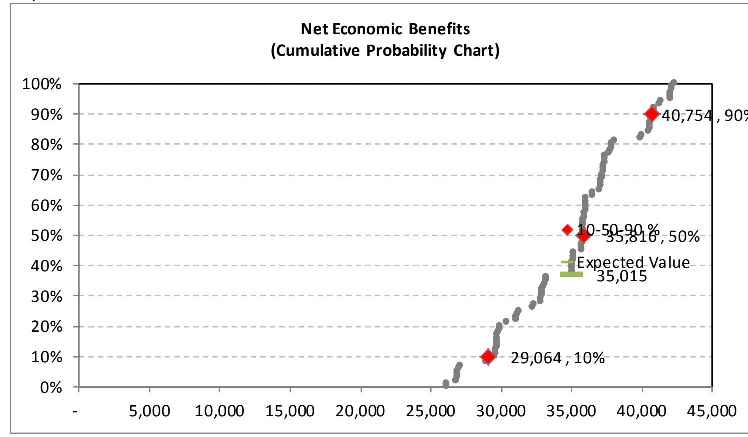
OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)

(AFUDC not included)

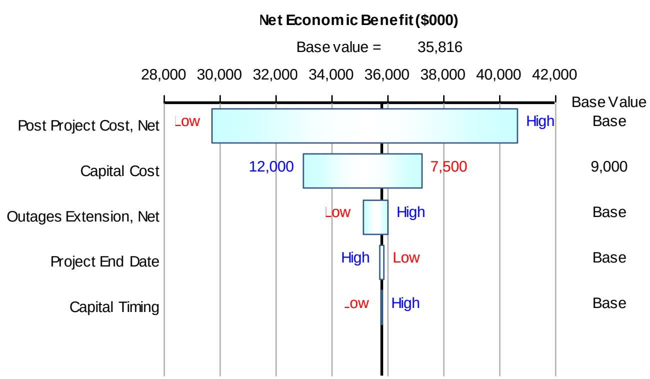


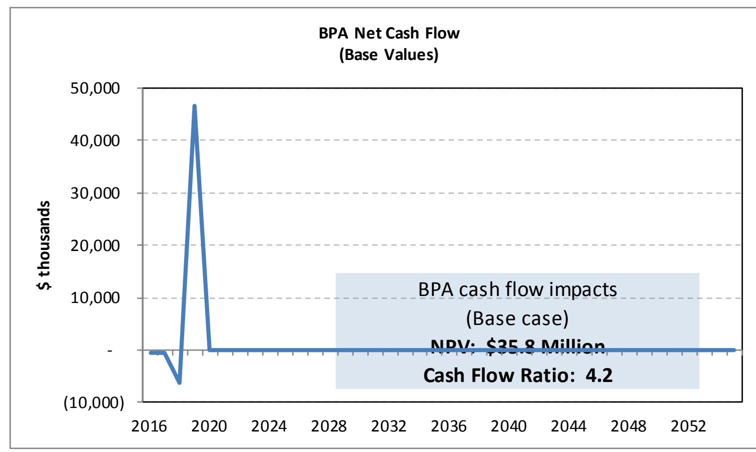


Net Economic Benefit Ratio: 3.96

For every dollar invested there is an net economic return of $3.96 (Expected value)

	10%	EV	90%
Investment Cost	7,060	8,835	11,297
Economic Benefits	38,195	43,850	49,129
Net Economic Benefits	29,064	35,015	40,754





Additional considerations:

Grand Coulee LPH-RPH Penstock Stoplogs

OP_CABRptText8

I-5 Corridor Reinforcement Project
Classification: Policy Commitment
Sponsoring Asset Category: Transmission

What is the proposed investment?
Construct two new 500kV Substations, Castle Rock and Sundial, and a new 79-mile 500kV transmission line to serve loads and accommodate transmission service requests along the I-5 corridor on the South of Paul and South of Allston Paths.

OP_CABRptText1

Why is this investment needed?
BPA needs to increase the electrical capacity and transfer capability of its 500-kV transmission system between the Castle Rock area in Washington and the Troutdale, Oregon area. This is in response to growing local demand for electricity and firm transmission requests that the BPA has received to move power across this portion of its system. A new 500-kV transmission line would increase the 500-kV transmission capacity in the southwest Washington/northwest Oregon area and allow BPA to provide for local load growth, maintain reliable power, and accommodate requests for long-term, firm transmission service. The new facilities would eliminate a transmission capacity constraint for this area, provide an additional electrical pathway, and increase system capacity. Continuing to use BPA's

What assumptions are behind the investment need?

OP_CABRptText2

· Key driver: Summer peak load conditions simultaneous with high transfers north-to-south along the main grid transmission system down the I-5 corridor.
· Combination of load service and accommodating 2008 Network Open Season requests determined original need date of 2016. The need date is currently determined to be 2021, which assumes that Pearl Bay Addition Upgrades (TFY100141) and Pearl 500 kV Upgrades (TS0140024) projects will be completed by 2016

OP_CABRptText3

What actions would be taken if this investment were not made?
With existing forecasts for load growth, BPA's analysis indicates that by Spring 2021 the existing transmission system's capacity on the SOA path will likely be reached and could require BPA to reduce power deliveries to the Portland area. Actions would include cutting schedules on the path (which results in curtailments of transfers on the path, starting with non-firm transfers). Generation re-dispatch is being considered as an interim solution if the project cannot be energized by the need date of Spring 2021.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?
Non-wires alternatives have been considered. Analysis has shown this is not a long term solution. At best it will push the need date of a new line out a several years.

OP_CABRptText5

Who would benefit from this investment?
Local loads in the southwest Washington/northwest Oregon area and requestors of long-term, firm transmission service

I-5 Corridor Reinforcement Project

OP_CABRptText6

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Oct-10	Jun-21	Jun-22	Jun-23	$652,513	$697,446	$755,092	$101,250	$18,575	$103,800	$171,301	$171,301	$294,526	$860,753	2%	50	60	70

What drives the investment costs to be low or high?

Investment cost totals above include not only forecasts for future years, but also FY09 through FY14 actuals. The costs are based on a 10% design.

Uncertainties regarding land acquisition for the preferred route (may be more difficult to acquire than expected), potential legal challenges resulting in project delays and increased costs, fluctuations in cost of materials (such as tower steel), possible mitigation for wetlands impact greater than anticipated (there are wetlands throughout the project area and it is possible that mitigation will be more extensive than expected, leading to increased costs).

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$235	$235
Present value:	$0	$9,934	$9,934

Benefits of the Investment

Benefit name	Benefit description	% of Total
Increased network wheeling revenues (PTP)	Adding transmission capacity in the South of Allston path enables incremental sale of firm, non-firm and network transmission capacity for new generation interconnections as accommodate future load growth	84%
Energy Delivered Cost	Adding transmission capacity in the South of Allston path impacts the cost of energy delivered throughout the region. Loads may e served with lower cost resources as a result of this addition.	5%
Outage and other costs	Transmission capacity expansion in the south of Allston path improves system reliability with regard to forced and planned transmission outages.	2%
Non-wires expense	As a contingency, BPA plans to implement non-wires program as stop-gap measure. The estimated annual cost is $2-5M per year to develop and implement up to 70MW capability by 2018.	N/A
Real Power Line Loss Savings	Higher transmission system line loadings results increases resistance and line energy losses. Adding transmission reduces resistive losses resulting in increase in energy delivered to serve load.	6%
Impact on other reliability investments	Assuming the I-5 Reinforcement project is energized by 2021, what impact will this have on other proposed reliability investments either delay or accelerate (both BPA and foreign).	4%
		0%

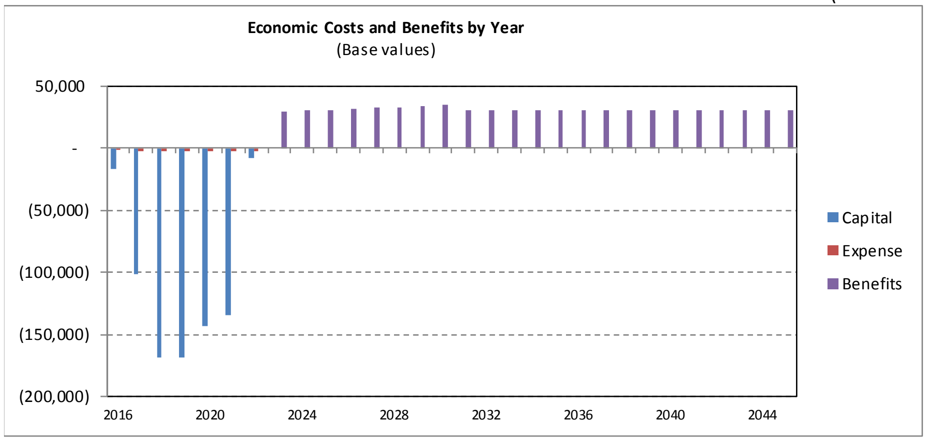
I-5 Corridor Reinforcement Project

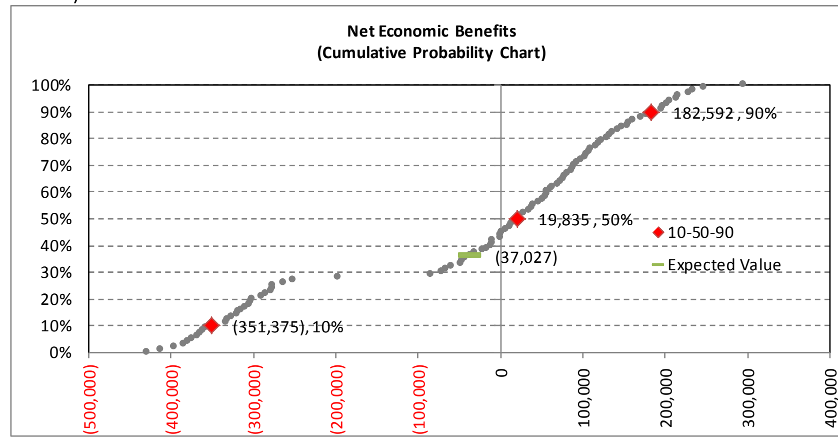
OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)

(AFUDC not included)

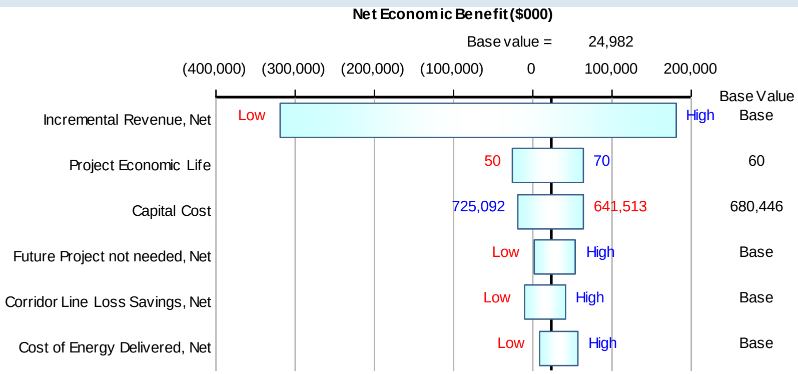


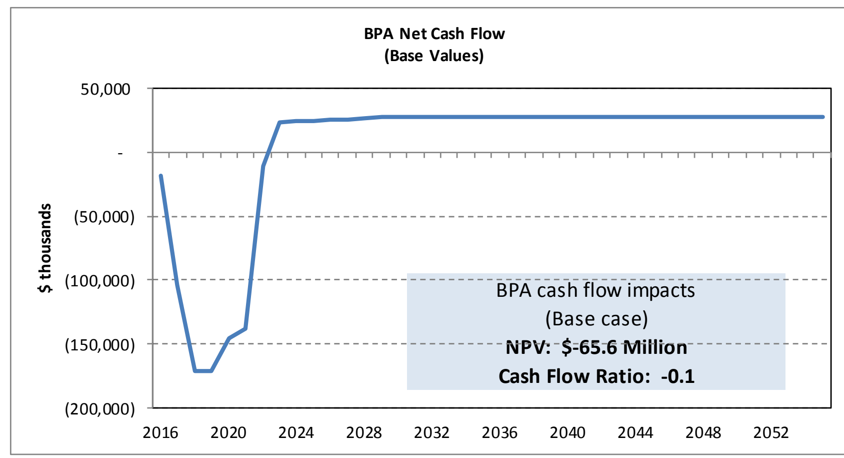


	10%	EV	90%
Investment Cost	656,260	701,700	745,215
Economic Benefits	364,924	664,673	890,265
Net Economic Benefits	(351,375)	(37,027)	180,472

Net Economic Benefit Ratio: -0.05

For every dollar invested, there is an net economic return of $-0.05 (Expected value)





Additional considerations:

South Idaho Load Service (SILS)
Classification: Discretionary
Sponsoring Asset Category: Transmission

What is the proposed investment?

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.

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 (or planned) by

OP_CABRptText1

Why is this investment needed?

PacifiCorp (PAC) has terminated the South Idaho Exchange and the General Transfer Agreement (GTA) with BPA. BPA must identify another means to deliver power to the BPA preference customers currently served by these two contracts. On October 2, 2012, BPA announced that it had completed an initial prioritization of potential service arrangements to serve BPA's southeast Idaho loads (SILS). BPA has identified the option of "Boardman-to-Hemingway (B2H) with Transmission Asset Swap" as the best option for SILS and concluded that it should be advanced by the agency in the near term as the top priority among the options.

What assumptions are behind the investment need?

OP_CABRptText2

OP_CABRptText3

What actions would be taken if this investment were not made?

BPA has contractual and statutory obligations to serve loads in SE Idaho. In the absence of additional transmission facilities, in order to serve the SE Idaho Loads BPA need to acquire energy within or near PacifiCorp's eastern system (PACE) and deliver it via Network Integration Transmission Service across PacifiCorp's transmission system to SE Idaho loads. Under most, if not all purchase scenarios, BPA will need to secure transmission capacity from Idaho Power to move purchased power to Goshen, in light of the system ownership arrangements that currently exist between PacifiCorp and Idaho Power in southern Idaho. In addition, depending on the location of specific power purchase or purchases, BPA may also need to secure transmission rights from transmission providers

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

OP_CABRptText5

Who would benefit from this investment?

Power and Transmission business lines

South Idaho Load Service (SILS)

OP_CABRptText6

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Jun-19	Jun-23	Jun-26	Jun-27	$239,249	$282,331	$367,436	$0	$0	$0	$0	$14,004	$336,086	$350,090	0%	45	50	70

What drives the investment costs to be low or high?

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$7	$7
Present value:	$0	$218	$218

South Idaho Load Service (SILS)

Kalispell to Kerr to Hot Springs Fiber Cable Installation
Classification: Discretionary
Sponsoring Asset Category: Transmission

What is the proposed investment?

The investment would comprise two components:
- Install fiber optic cable in the Overhead Ground Wire (OHGW) between the Kalispell and Kerr Substations
- Install 22 miles of All-dielectric Self-supporting (ADSS) fiber between the Elmo and Hot Springs Substations.

The investment would be coordinated with the transmission line rebuild (part of sustain) from Kalispell Sub to Kerr Sub (41.4 miles), which includes OHGW.

OP_CABRptText1

Why is this investment needed?

Currently Transmission does not have communication capability into Kerr Substation. With the addition of the fiber cable RAS can be installed at Kerr Sub. The addition of RAS, will enable Hungry Horse Dam to increase its output by 50 to 75 MW per year. The increase would help mitigate both fish and water quality issues for the Bureau of Reclamation (USBR).

What assumptions are behind the investment need?

OP_CABRptText2

The Kalispell - Kerr line rebuild continues as planned within the wood-pole sustain program.

OP_CABRptText3

What actions would be taken if this investment were not made?

The fiber cable installation would be delayed until at least 2023, after completion of the Kalispell to Kerr line rebuild. This would potentially extend the NEPA process, cause Bureau of Land (BL) and tribal issues, because of the repeated access to their lands; which would increase costs significantly, possibly upwards of $2M.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

The fiber cable installation would be delayed until 2023. This would place the USBR at risk for high nitrogen levels in the water and failure to meet the Bull Trout biological opinion.

OP_CABRptText5

Who would benefit from this investment?

BPA Power and the USBR will be the primary ones beneficiaries. Also, BPA the investment will increase Transmission's bandwidth on the Montana communications system, supporting future separate projects, such as OMET.

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Oct-14	Jun-18	Sep-18	Jun-19	$6,040	$6,300	$9,032	$78	$0	$3,925	$3,798	$0	$0	$7,800	1%	20	25	30

What drives the investment costs to be low or high?

Weather and environmental concerns could affect the project costs.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$13	$16	$3
Present value:	$189	$252	$62

Benefits of the Investment

Benefit name	Benefit description	% of Total
Communication Capacity Value	Currently this area of Montana has limited capacity to accommodate increasing demands for communications traffic. Addition of this fiber will serve a variety of communications needs over its expected life.	63%
Avoided costs of delaying fiber addition	Kalispell to Hot Springs 230 kV Line is scheduled to be rebuilt in 2018. This fiber will need to be added within next 10 years to accommodate growth. If delayed, it will require a planned line outage and higher cost to add the fiber optic line.	37%
Dark fiber	Limitted opportunity to lease dark fiber	1%
Equipment maintenance and reliability	Increased ongoing costs of operation, maintenance and repair for new Fiber, offset to benefits of the system addition	-1.0%
		0%
		0%
		0%

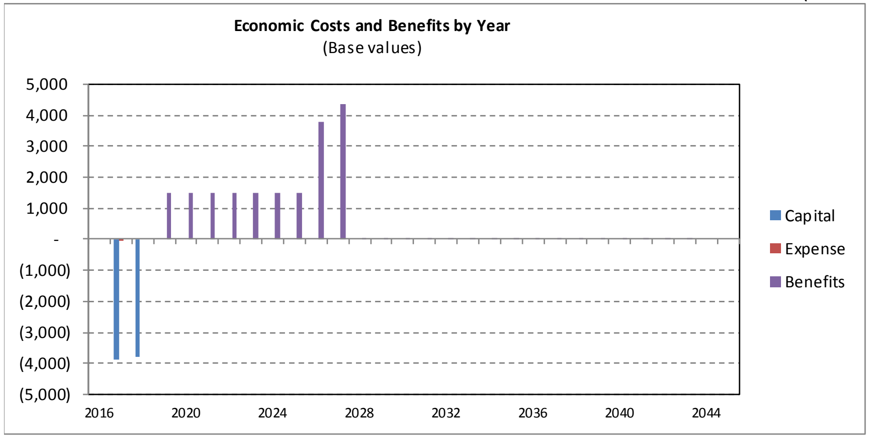
Kalispell to Kerr to Hot Springs Fiber Cable Installation

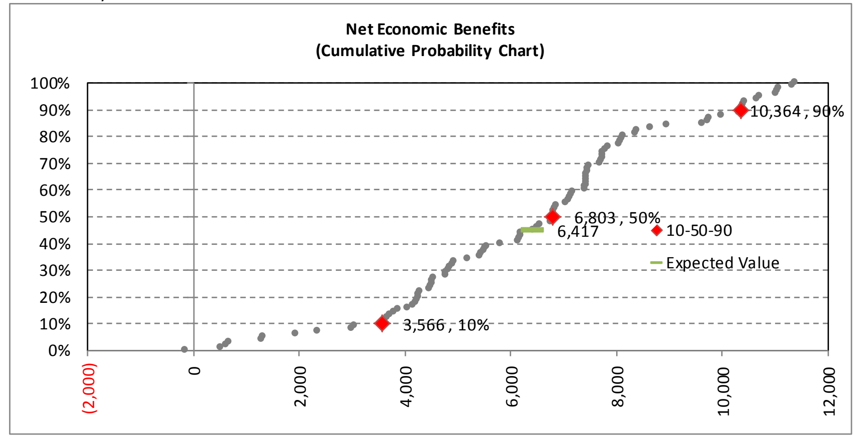
OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)

(AFUDC not included)

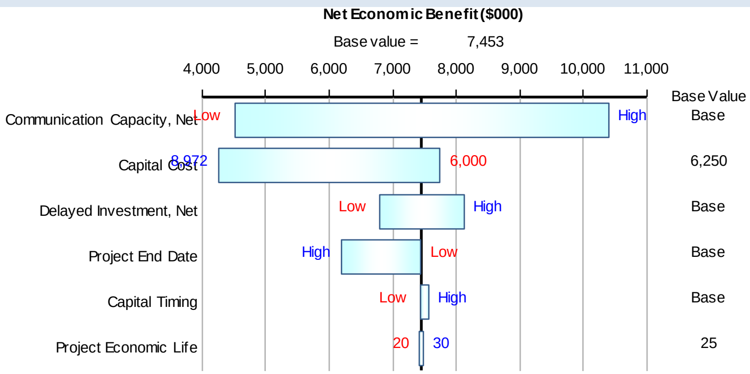


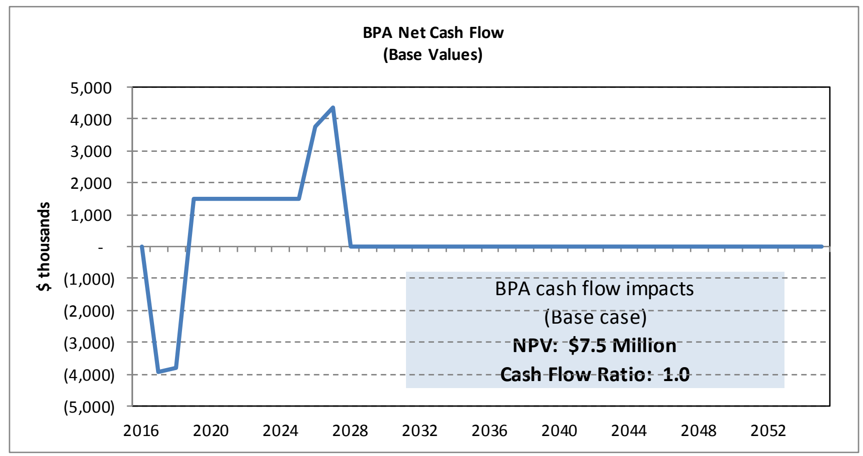


	10%	EV	90%
Investment Cost	7,097	8,090	10,588
Economic Benefits	11,659	14,507	17,780
Net Economic Benefits	3,566	6,417	10,362

Net Economic Benefit Ratio: 0.79

For every dollar invested, there is an net economic return of $0.79 (Expected value)





Additional considerations:

McNary Project Storage Building
Classification: Discretionary
Sponsoring Asset Category: Federal Hydro

What is the proposed investment?

A new, permanent 15,000 square foot storage building, sized 156 ft by 100 ft and two concrete building aprons (each 6000 square feet), located at the McNary project site. The investment will provide much needed floor space to inventory parts received and securely store the equipment until thier installation occurs.

OP_CABRptText1

Why is this investment needed?

Upcoming rehabilitation and replacement projects at McNary Dam will require storage for large pieces of equipment and a myriad of smaller parts. For example, new turbine runners are scheduled to be installed on all 14 main generating units. The runner procurements will result in the need of additional storage space for equipment and parts until the installation work can be staged and implemented. Limited storage space and, for that matter, space in general within the McNary Powerhouse is not possible to sustain runner replacements. Therefore, a 15,000 square foot storage building, sized 156 ft by 100 ft and two concrete building aprons (each 6000 square feet), will provide much needed floor space to inventory the parts received, and to securely store the equipment until the installation can be properly scheduled. Large scale capital equipment investments scheduled for the next 10+years will require additional space to safely store the materials and allow for efficient and timely execution of the runners installation phases of work.

OP_CABRptText2

What assumptions are behind the investment need?

R

OP_CABRptText3

What actions would be taken if this investment were not made?

Mechanics will continue to take additional precautions to ensure their own safety and maintain a high standard of quality control for end users. Loss of productivity will continue to be manifest in frequent overtime hours and reliance on outside vendors. Because corrective facility improvements will require greater than 60% rebuild of structural and building systems, expansion/remodeling of an existing facility was rejected as cost prohibitive.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

Expansion/remodel of existing facility at McNary: This alternative would be in lieu of a new building. It was rejected because corrective facility improvements would require greater than 60% rebuild of structural and building systems, which would be significantly higher in cost than new construction.
Acquire leased storage space in Walla Walla: This alternative would lease storage space in lieu of building a new facility on-site. The costs of leasing were evaluated, and found to be similar to the preferred alternative. In addition, this alternative would entail travel, fuel and other transportation costs, and lead to a six month delay in the McNary Turbine Runner

OP_CABRptText5

Who would benefit from this investment?

Army Corps of Engineers, Bonneville Power Administration

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Oct-13	Mar-18	Sep-18	Oct-19	$4,000	$4,389	$5,500	$483	$44	$2,282	$1,580	$0	$0	$4,389	0%	30	45	60

What drives the investment costs to be low or high?
New construction costs for warehouse structures don't have the variability of other hydro investments. Bid uncertainty on the project drives the low and high estimates.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$9	$9
Present value:	$0	$237	$237

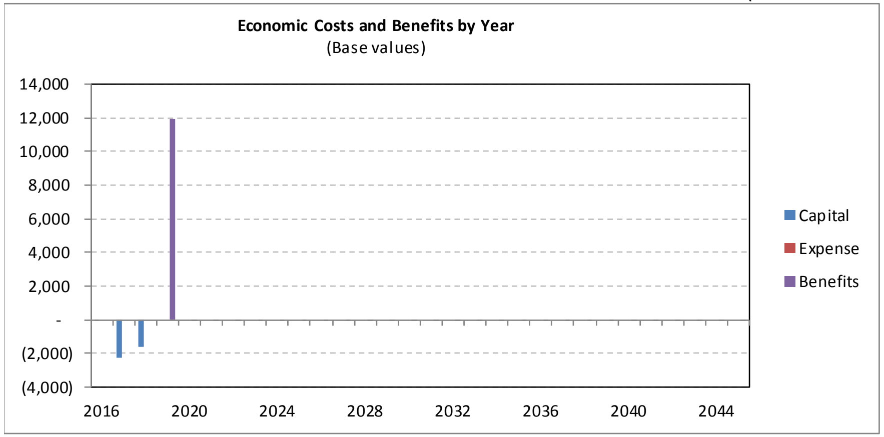
Benefits of the investment

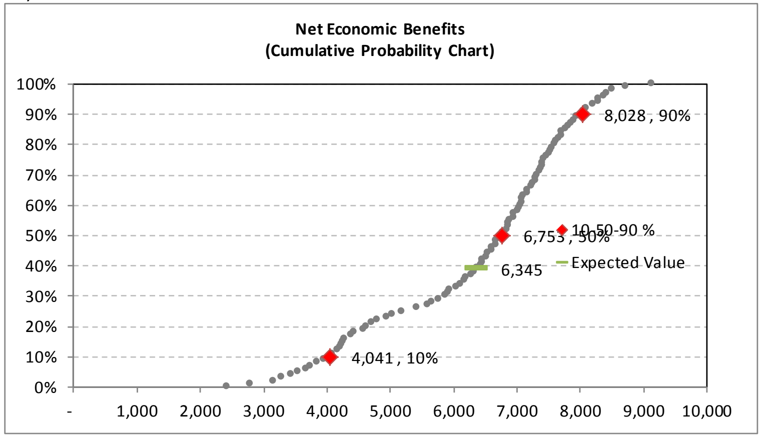
Benefit name	Benefit description	% of Total
Risk Reduction Benefit	Absent this project, there would be a delay in the McNary Turbine Runner Replacement of one year while the contractor constructed a temporary storage building. That one year delay pushes out the benefits of the runner project by one year. LGR and DCR reductions foregone total $5.907 million.	49%
Spill Capture Benefit and Efficiency Benefit	Foregone spill capture and efficiency improvements for that one year total $1.51 million.	13%
Avoided temporary construction costs	$4.546 million in temporary facility construction costs will be avoided if a permanent structure is built.	38%
		0%
		0%
		0%
		0%

McNary Project Storage Building

OP_CABRptTable

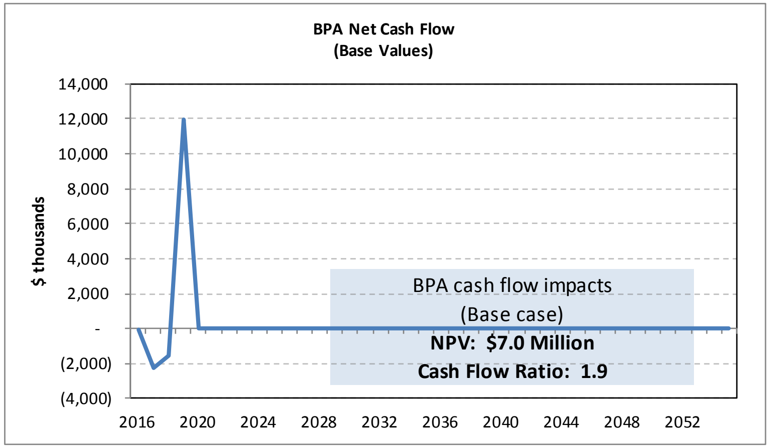
Net Economic Benefits and Cash Flows
(2016 dollars in thousands)
(AFUDC not included)





Net Economic Benefit Ratio: 1.63
For every dollar invested there is an net economic return of $1.63 (Expected value)

	10%	EV	90%
Investment Cost	3,417	3,899	4,698
Economic Benefits	7,913	10,244	11,761
Net Economic Benefits	4,041	6,345	7,976



Additional considerations:

McNary Project Storage Building

OP_CABRptText8

Midway - Ashe 230kV New Double Circuit Line
Classification: Discretionary
Sponsoring Asset Category: Transmission

What is the proposed investment?

The investment is to construct a double circuit 230kV line; one circuit will be between BPA Midway and Ashe substations, the other replacing the DOE R Midway-HEW # 2 line. DOE Richland will pay a share of the overall costs that equates to the costs they would have borne had they rebuilt the Midway-HEW # 2 line.

OP_CABRptText1

Why is this investment needed?

The proposed investment would give BPA ownership and control of the accredited pathway to Columbia Generating Station (CSG) Nuclear Power Plant and reduced expense payments of more than $1M annually.

What assumptions are behind the investment need?

OP_CABRptText2

The current accredited path for offsite power safe shut-down of the CGS Nuclear Power Plant is the Midway - (HEW) # 1 line owned by DOE Richland (DOE R). The line is part of the DOE R double circuit 230kV line between Midway and HEW, connecting into the BPA Ashe substation via two BPA owned taps. Due of it's # 1 line being the aforementioned accredited pathway, DOE R is the registered Transmission Operator (TO). Because of BPA's reliance on the accredited pathway, it has entered an arrangement with DOE R where it reimburses them for all costs associated with being

OP_CABRptText3

What actions would be taken if this investment were not made?

DOE R would continue as the TO and would rebuild its # 2 line. BPA would pay DOE R annual wheeling fees of approximately $300,000 and an estimated reimbursement of annual costs of being the TO of $400,000. In addition DOE R has agreed to install fiber and terminal equipment to provide BPA dispatch visibility and control of the line. The costs of the latter are estimeated to be $2.4M in capital plus $280,000 annually in lease and maintenance charges.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

If BPA decides to not move forward, DOE Richland would rebuild the existing 230kV line for only their purposes and BPA would pay DOE Richland approximately $2.4M in 2016 for new Fiber communication and $1M annually thereafter for wheeling, TO reimbursement and fiber lease and maintenance charges.

OP_CABRptText5

Who would benefit from this investment?

DOE R benefits by disconnecting from BPA’s Ashe Substation and de-registering from WECC as a TO.
CGS benefits by BPA becoming the owner and operator of their accredited path for safe shut down of the nuclear plant and no longer being vulnerable to outages causes by a foreign utility.
BPA Tri Cities District benefits by not being exposed to foreign utility activities causing outages on the Midway to Ashe transmission path.
BPA Operations benefits from improved system flexibility.

Timing and Costs of the Investment

(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Mar-16	Mar-18	Dec-18	Sep-19	$17,360	$19,660	$26,209	$0	$244	$8,532	$10,970	$4,632	$0	$24,378	0%	40	50	70

What drives the investment costs to be low or high?

The high range assumes that DOE Richland does not pay for the portion of the work currently assumed to be their responsibility. The low range assumes that they do pay for their portion of the work.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$38	$38
Present value:	$0	$1,233	$1,233

Benefits of the Investment

Benefit name	Benefit description	% of Total
One-time Avoided Cost	One-time avoided capital cost of $2.4 million for Communications equipment that won't be needed once this project is completed.	4%
Avoided TO Costs	Avoided transmission wheeling reimbursement and transmission operator costs of $1 million per year.	45%
BBO	Reduced risk of BBO at CGS Nuclear station	14%
Loss Generation Risk Reduction	Line outages great than 72 hours NRC requires nuclear plant to shut down	33%
Line Outage reduced risk	Midway - Ashe 230 kV line currently has frequent unplanned outages. Once project is complete, signficant reduction in Line outages.	3%
Compliance Benefit	Everytime Midway to Ashe Line is disrupted NRC requires Energy Northwest to report. Costs of reporting will be mitigated by this project.	1%
		0%

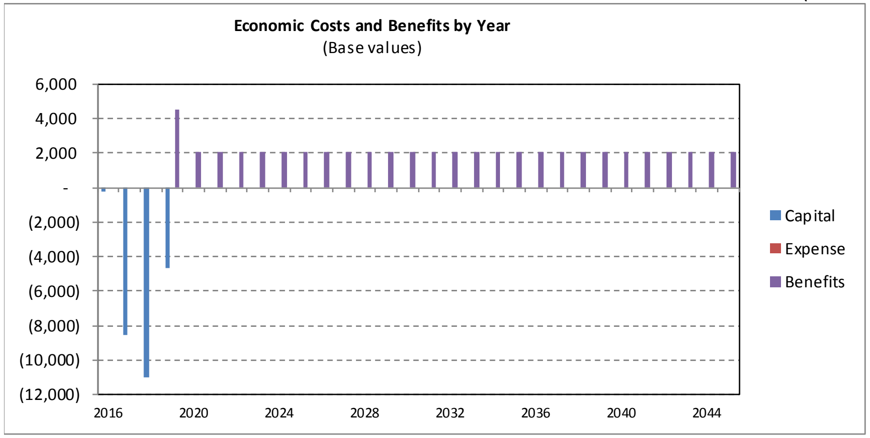
Midway - Ashe 230kV New Double Circuit Line

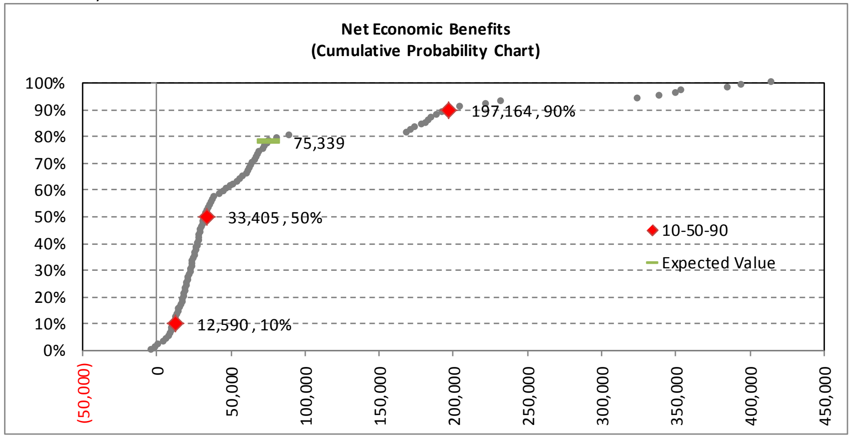
OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)

(AFUDC not included)

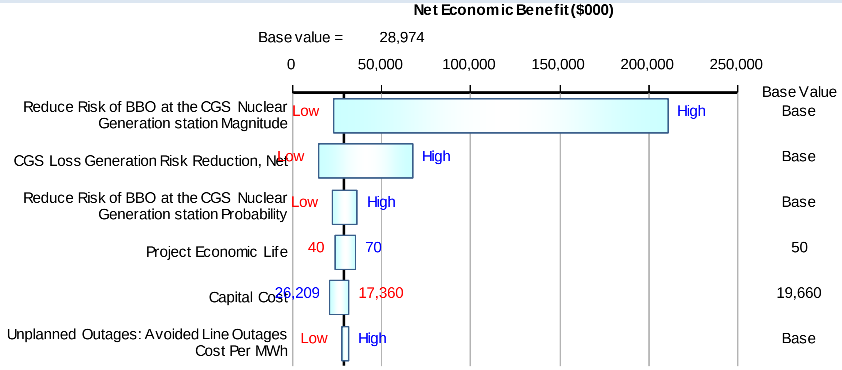


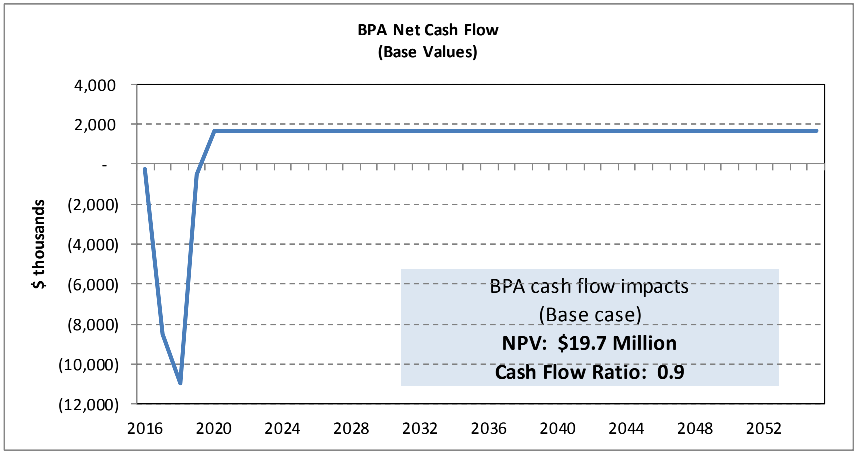


Net Economic Benefit Ratio: 3.09

For every dollar invested, there is an net economic return of $3.09 (Expected value)

	10%	EV	90%
Investment Cost	20,404	24,368	30,804
Economic Benefits	36,558	99,641	219,737
Net Economic Benefits	12,590	75,339	196,647





Additional considerations:

Midway - Ashe 230kV New Double Circuit Line OP_CABRptText8

L0389 UEC Industrial Load Expansion
Classification: Policy Commitment
Sponsoring Asset Category: Transmission

What is the proposed investment?

The proposed investment is to significantly expand the existing BPA owned Morrow Flat Substation at the Port of Morrow and tap an existing line from McNary Substation to accommodate an additional 450MW of load.

OP_CABRptText1

Why is this investment needed?

A large industrial database customer has demonstrated a pattern of steady growth since 2012 and is looking at several sites in UEC's service territory for expansion.
With BPA's existing transmission infrastructure we cannot fulfill the customers requested load service. The service would be radial feed out of each substation with partial to full capacity available through the new Umatilla electric transmission system.

What assumptions are behind the investment need?

OP_CABRptText2

Umatilla Electric Cooperative (UEC) is a Network (NT) Integration Transmission Service customer, through Pacific Northwest Generating Cooperative (PNGC). UEC has a large industrial database customer located in the Hermiston, Oregon area who is looking to expand up to 450MW of additional load that would be served out of the Hermiston area. The large industrial database customer has demonstrated a pattern of steady growth since 2012 and is looking at several sites in UEC's service territory for expansion.

OP_CABRptText3

What actions would be taken if this investment were not made?

Any additional load would be restricted to the existing capacity available at Morrow Flat, Boardman and McNary Substations. Without having certainty of needed ampacity for future load growth the large industrial customer would most likely search other service areas. Taping the existing ampacity at each location would make McNary service region less robust and put other utilities in the area at risk for decreased service reliability and greater potential for power outages.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

"Do nothing Option" - BPA would not fulfill its obligations under the OATTand would result in UEC's large industrial customer searching other alternative locations outside of BPA's service territory.
Option 2 - Combine this project with the future Stanfield Substation, which will likely be built to serve additional wind generation in the area. This would not meet the customer time lines.
Option 3 - Expand at different BPA owned substations to meet the additional 450MW of load, adding another 500/230kV transformer at the BPA McNary substation along with purchasing land and expanding the 230kV bus at Boardman. This alternative would be more expensive.

OP_CABRptText5

Who would benefit from this investment?

BPA Transmission, Umatilla Electric COOP, Pacific Northwest Generation COOP, UEC's large industrial customer (VA DATA)

L0389 UEC Industrial Load Expansion

OP_CABRptText6

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Dec-16	Sep-18	Sep-19	Sep-20	$7,500	$8,800	$12,000	$0	$0	$2,728	$6,547	$1,637	$0	$10,912	0%	40	50	60

What drives the investment costs to be low or high?

The main drivers in cost are dependent on the final scope of the project. UEC and BPA must agree on a plan of service that meets the load needs, which may involve service at a different voltage than expected. Project scoping will help better define the project.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$10	$10
Present value:	$0	$313	$313

L0389 UEC Industrial Load Expansion

Ross Central Circulation Development
Classification: Discretionary
Sponsoring Asset Category: Facilities

What is the proposed investment?

A new 52’ wide road section which replaces the circuitous 26’ road configuration. The new road will include stormwater management, and integrate pedestrian and bike circulation.

OP_CABRptText1

Why is this investment needed?

The investment seeks to enhance workflow and safety at the Ross Complex by solving poorly planned road infrastructure and outdoor workflow spaces where east side and west side circulation meet. The area connects the two main roads on the complex, North Road and Ross Canyon Road and houses four main industrial functions: The Ross Warehouse, PSB General Shops, HAZMAT operations and the Investment Recovery Center. Under the existing arrangement, east-west traffic must pass through a dogleg turn which is sufficiently narrow that extended vehicles must cross into the oncoming traffic lane to navigate. Further, the road bisects a Logistics work zone that does not have clear boundaries making it a confusing area to navigate for visitors not familiar to this part of the Complex. The proposed investment will provide new ingress and egress points to each function which optimizes their work flow and separates traffic from internal work zones. The investment will also provide distinct lanes for multiple modes of circulation with a new 54’ road section that accommodates motorized vehicles, bicycles and pedestrians. The new road section integrates onsite stormwater management which ultimately reduces BPA’s stormwater flows to the area watershed and reduces the City of Vancouver’s stormwater fee.

OP_CABRptText2

What assumptions are behind the investment need?

The Ross Complex has several important uses: general office, control center operations, lab testing and logistics. As the Ross Complex has developed over time, the circulation has grown organically to serve new uses and mitigate topography changes. The lack of planning however has resulted in a circulation scheme that does not provide optimal access points to work zones, does not safely handle non-motorized circulation and does not support future facility investments under the Ross Strategic Famework Plan which further optimize Ross Complex land use. Most

OP_CABRptText3

What actions would be taken if this investment were not made?

The alternative to this investment is the status quo. BPA will continue to accept the liability of traffic conflicts between extended vehicles and other circulation. Stormwater management and potential savings from reduced City of Vancouver stormwater fees will be deferred to future investment initiatives. Non-automotive travel through the middle portion of the Ross Complex will continue to be obstructed by a lack of circulation options.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

The only identified alternative to new road construction is the status quo.

OP_CABRptText5

Who would benefit from this investment?

Fleet (NSF), Logisitics (NSL), General Craft Services (TFHG), general office travel between Dittmer and CSB buildings.

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Feb-17	Jan-19	Apr-19	Jul-19	$2,408	$2,890	$4,335	$0	$0	$538	$1,434	$1,613	$0	$3,584	0%	40	60	70

What drives the investment costs to be low or high?
The primary cost driver is the amount of regrading required. There may be multiple design options, each with different degrees of site work. It is possible that a lower cost design alternatives will be idenfitied which meets all the project objectives. However, because the project has not progressed through design and engineering, a high baseline cost has been assumed.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$8	$12	$4
Present value:	$340	$490	$149

Ross Central Circulation Development

Ross Cold Creek Connection
Classification: Discretionary
Sponsoring Asset Category: Facilities

What is the proposed investment?

A two-way, single span overfilled precast concrete arch bridge crossing on spread footings that will span over the Cold Creek railway linking the Cold Creek Yard and Ross Complex. This will begin at the Ross Complex along 15th avenue extending north across the railroad crossing into the laydown yard where the new MHQ building is being constructed.

OP_CABRptText1

Why is this investment needed?

The Cold Creek Yard is an isolated lay-down storage parcel utilized by the Ross Warehouse north of the Ross Complex. It is separated by the from the Ross Complex secure perimeter by the Cold Creek canyon and the Portland Vancouver Junction Railroad (PVJR). There is no direct connection between these properties. The Ross Warehouse currently transports materials to and from Cold Creek with a caravan of forklifts utilizing safety escorts over Minnehaha Street and through the Ross Complex. This practice is time consuming and carries inherent safety risks as vehicles must travel slowly with a payload while sharing the road with faster moving traffic. The process of securing materials which are transferred back and forth over public roadways is significantly more time consuming than transferring materials on BPA property. Additionally, the Ross MHQ facility will be commissioned on the Ross Complex no later than early 2018. A direct connection to the Ross Complex will support faster MHQ access to the Ross Control House and support services for Transmission Field Operations. The investment objective is to increase employee safely by providing a direct connection between Cold Creek and the Ross Complex, significantly reducing trip distance and completely eliminating unsafe traffic conflicts on public roadways.

OP_CABRptText2

What assumptions are behind the investment need?

The Cold Creek Crossing was originally secured as a pathway for conductors which tie into the Ross Substation. Over the past 30 years, it has gradually been populated with BPA Logistics, MHQ and Fleet functions due to lack of space within the Ross Complex secure perimeter. This project assumes the Cold Creek yard will continue to be used the forseeable future.

OP_CABRptText3

What actions would be taken if this investment were not made?

Warehouse operations will account for safety concerns through advanced planning of materials transport over public roadways and more additional materials tie down procedures both at a cost of increased man-hours. Ross MHQ groups will also continue to travel 2 miles over Minnehaha Street to re-enter BPA property.

To address safety concerns, multiple fork lifts will need to be purchased as well as a new pole barn to house the equipment at Cold Creek to allow adequate safe response to emergencies and

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

An alternate study was performed for a grade crossing was considered. This included a conceptual sketch, identifying max working grade (15%). Design grade crossing averages (3% and 7% for a 160-ft stretch on the north side of the proposed road. This alternative was not selected due higher cost and lower value. Factors in this decision included: significant amount of earthwork, storm water management, increased maintenance costs, railroad owner crossing preferences, and increased travel time.

OP_CABRptText5

Who would benefit from this investment?

BPA Logistics (NSL), Ross District Transmission Field Operations (TFV), Fleet Services (NSF), Ross Facilities (NWMR)

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Jan-18	Mar-18	Oct-19	May-20	$2,891	$3,180	$3,816	$0	$0	$0	$1,577	$2,366	$0	$3,943	0%	40	75	100

What drives the investment costs to be low or high?

Primary drivers of cost from low to high include: site development, earthwork grading of ancillary areas supporting the bridge, and storm water considerations.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$25	$21	-$4
Present value:	$1,428	$1,256	-$172

Benefits of the investment

Benefit name	Benefit description	% of Total
Productivity	Operational Productivity Improvements derived from a reduced travel time to the Cold Creek Yard.	95%
Energy reduction	Reduced energy needs due to travel time being reduced. This will result in less fuel and energy being expended driving to and from the Cold Creek Yard.	5%
		0%
		0%
		0%
		0%
		0%

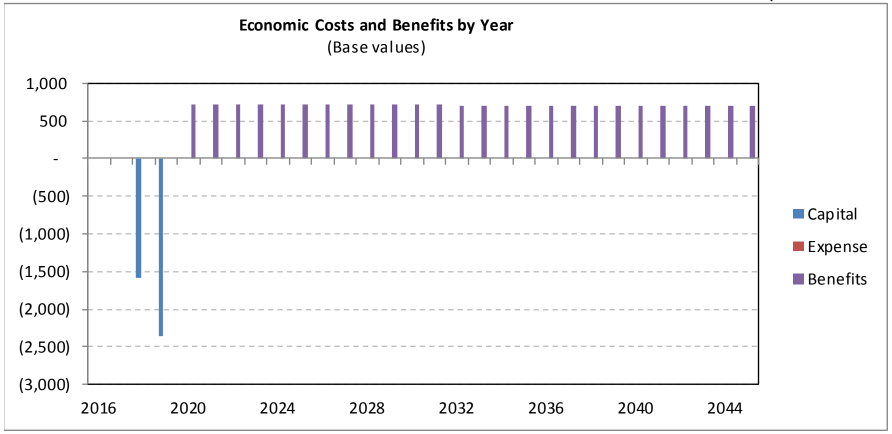
Ross Cold Creek Connection

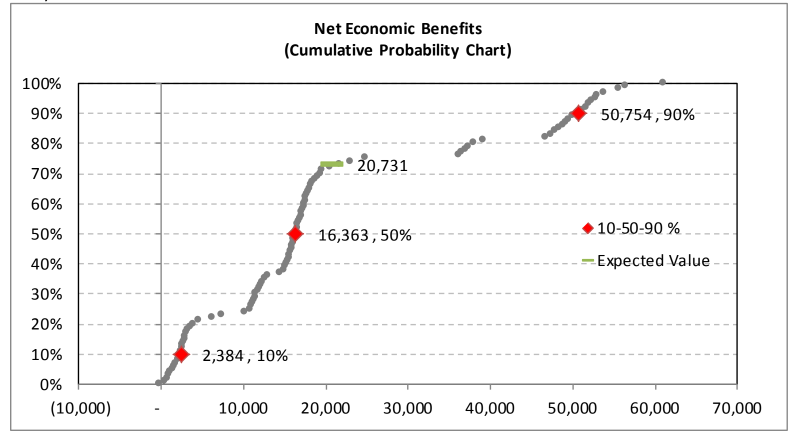
OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)

(AFUDC not included)

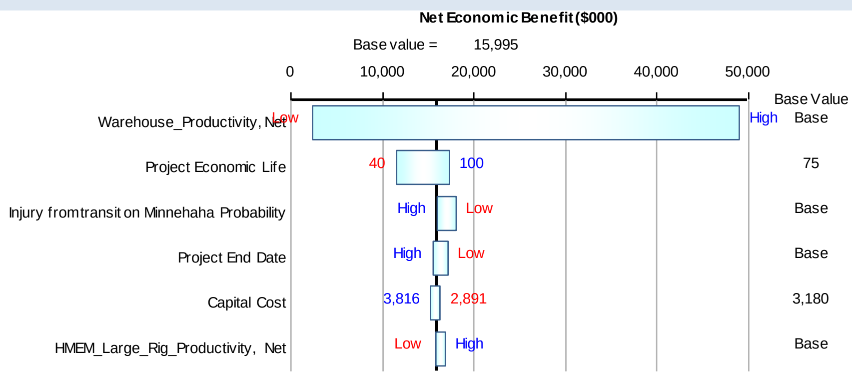


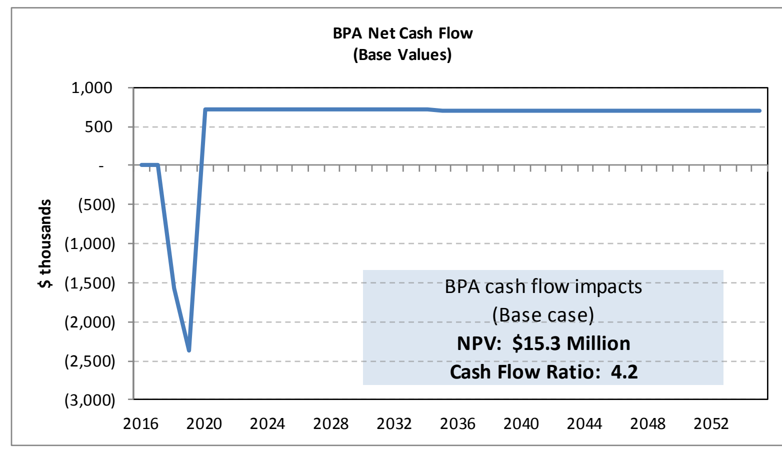


Net Economic Benefit Ratio: 5.53

For every dollar invested there is an net economic return of $5.53 (Expected value)

	10%	EV	90%
Investment Cost	3,320	3,750	4,382
Economic Benefits	5,796	24,429	54,602
Net Economic Benefits	2,384	20,731	50,754





Additional considerations:

This investment is part of Facilities programmed spending. It is not an additional request beyond the approved CIR funding.

Ross Cold Creek Connection

OP_CABRptText8

Ross HMEM Garage Replacement
Classification: Discretionary
Sponsoring Asset Category: Facilities

What is the proposed investment?

A new, right sized HMEM Garage and Fleet administrative headquarters to consolidate vehicles at regional facilities and reduce contracted maintenance. The new HMEM garage is to include site development for consolidation of loan pool vehicles and administrative office space for 15 Fleet staff.

OP_CABRptText1

Why is this investment needed?

The existing Ross HMEM Garage is inefficient and has a number of facility related safety concerns. This investment will enable the Fleet administrators and shop mechanics to achieve greater QC of critical HMEM maintenance activities in a more efficient manner and with less staff. It will address numerous facility related safety concerns that slow garage operations and present an undue risk to mechanics. It will enable sensitive work involving heavy equipment (boom lift removal and heavy equipment service, e.g.) currently performed outside to be moved indoors into a controlled environment. It is anticipated that productivity will improve substantially with the addition of proper fall protection, bridge cranes, dedicated work bays, and improved lighting and ventilation afforded by taller ceiling heights and appropriate building systems. Campus safety is also expected to be enhanced through reduced circulation conflicts between personal vehicles and heavy machinery entering and leaving the South Ampere building.

OP_CABRptText2

What assumptions are behind the investment need?

Fleet services will continue to be an enduring and necessary function to the BPA Transmission system.

OP_CABRptText3

What actions would be taken if this investment were not made?

Mechanics will continue to take additional precautions to ensure their own safety and maintain a high standard of quality control for end users. Loss of productivity will continue to be manifest in frequent overtime hours and reliance on outside vendors. Because corrective facility improvements will require greater than 60% rebuild of structural and building systems, facility reinvestment is deemed a poor investment option.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

(1) Mulit-Vendor Outsourcing: A vendor model has been evaluated and deemed more expensive than in-house service. Additionally, the diverse skillset is increasingly lacking at available vendor services, quality control is lower and timely support for emergency field repair will be limited. This alternative does not satisfy criteria of cost, quality of workmanship or service reliability. (2) Facility upgrades: There is only 30% of the required space for a right-sized HMEM facility at South Ampere. Further, comprehensive safety upgrades will require substantial replacement of a 1942 building. Facility upgrades will be expensive yet will not comprehensively address safety and efficiency issues making this a poor investment option. (3) Downsize Ross Garage Operations / Addition to Field Sites: This alternative proposes a two bay addition to the Pasco facility and a corresponding reduction of two shop mechanics at Ross (from 7 to 5). The Ross Garage does not undergo any major capital investments under this scenario. To address immediate safety concerns surrounding the facility, the 15th Street Gate will be relocated and office functions directly adjacent to the Garage are moved to lease facilities. While this scenario improves safety conditions, it does not comprehensively address facility safety at Ross (lack of bridge crane) or substantial improvements to productivity (undersized bays and total number of bays). Each HMEM facility operates with a work backlog and there are no operational economies to be gained by redistributing work to different sites. This alternative will shift the burden of service backlogs and mechanic's overtime (or vendor costs) but better value over the preferred alternative because the unit costs of construction are not lower. Integration with existing structure, slower construction schedule (to maintain continuity of operations) and lower economies of scale are all contributors to a higher cost of construction. Including construction costs, vendor costs, office relocation and vehicle transfer costs, this option is projected to cost $34.2M over 30 years (capital + expense, 2016 dollars). This alternative is not recommended as it does not comprehensively address safety issues, productivity or long term facility asset management at the South Ampere Garage. (4) Smaller scale Ross HMEM Garage: Under this alternative the number of bays is reduced by (4) bays - a 20% reduction. Direct facility construction costs are estimated to go down from $24.2M to $21.3. This option will also result in the relocation of one mechanic and an approximate 10% loss in productivity from the preferred alternative. Safety concerns and 2/3rds of mechanic's performance are addressed however, this option does not completely eliminate the garage work backlog. Vendor costs, rental fees and overtime are anticipated to cost approximately $260k/year more than the preferred alternative resulting in a 30 year cost of $31.4M (direct capital, FY16$). (5) Full Garage Alternative (Consultant Recommended): This alternative was proposed in Cycle 4 Prioritization and included covered parking for loan pool vehicles, larger site development area (~7 acres) and (19) bays instead of the (15) bays proposed under the preferred alternative. Project cost is projected to be $29.1M in direct capital. This alternative provides the space flexibility for future increases to workflow. However, it is not essential to the project goals of relocating and right-sizing operations for improved safety and productivity optimization. This alternative is not recommended due to cost considerations.

OP_CABRptText5

Who would benefit from this investment?

NWM, NS, NSF, NSFS, S, NW, J, NWS, NN, NWFR, NF

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Feb-17	Jun-19	Dec-19	Jun-20	$22,980	$25,534	$28,087	$0	$0	$4,749	$1,900	$25,743	$1,355	$33,747	6%	50	60	70

What drives the investment costs to be low or high?

The project costs are based on a detailed 2012 feasiblity study for process improvement and facility replacement. However site design, facility engineering & specifications and contractor pricing are typically capitalized costs and not undertaken until there is an approved project. This stage of development carries cost uncertainty to scope, constructibility and contractor pricing which are reflected in the high and low range of investment costs.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$200	$131	-$69
Present value:	$8,459	$5,544	-$2,915

Benefits of the investment

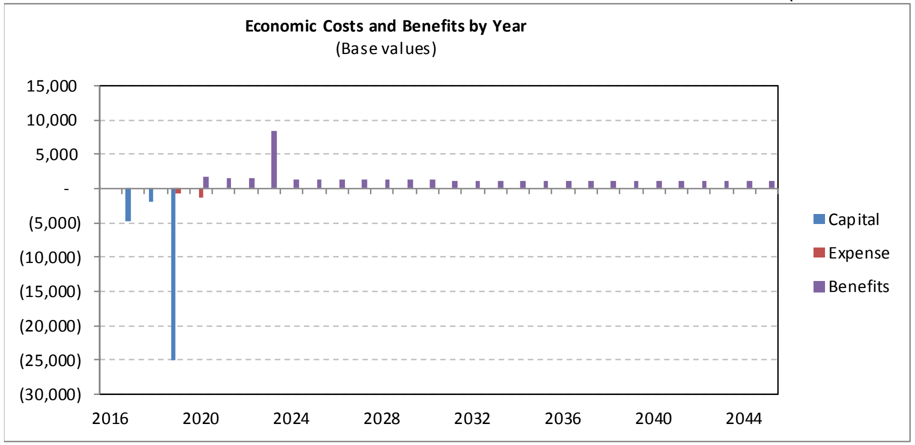
Benefit name	Benefit description	% of Total
Greater Shop Efficiency	Better facility support increases productivity, reduces employee count, reduces vendor costs and reduces overtime.	57%
Greater Admin Efficiency	Co-location reduces the number of all staff meetings, enables better team coordination and reduces time spent in transit.	9%
Avoided Office Lease Costs	Provision of additional office space will allow BPA to avoid a cooresponding amount of lease space in the Vancouver area.	10%
Avoided Facility Upgrade Costs	Without investment BPA will need to make facility upgrades to address safety deficiencies and obsolecense	23%
Operations and Maintenance	Avoided O&M Costs (base-new) for total ongoing costs	<1%
		0%
		0%

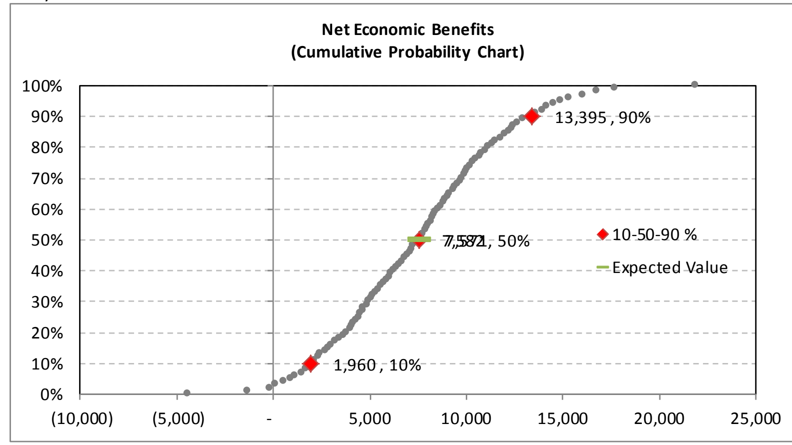
Ross HMEM Garage Replacement

OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)
(AFUDC not included)

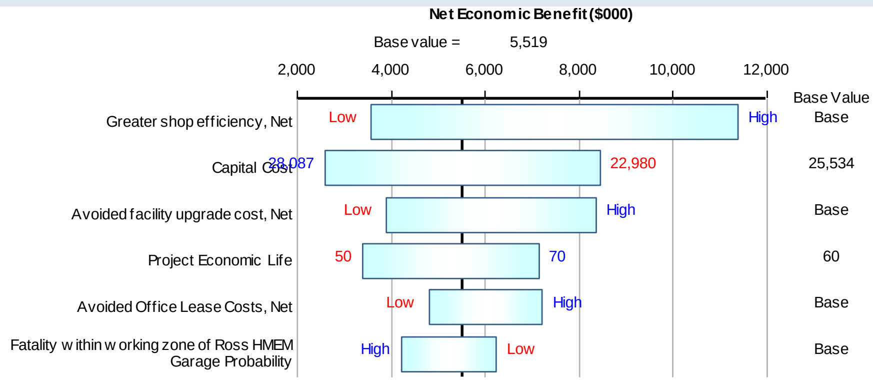


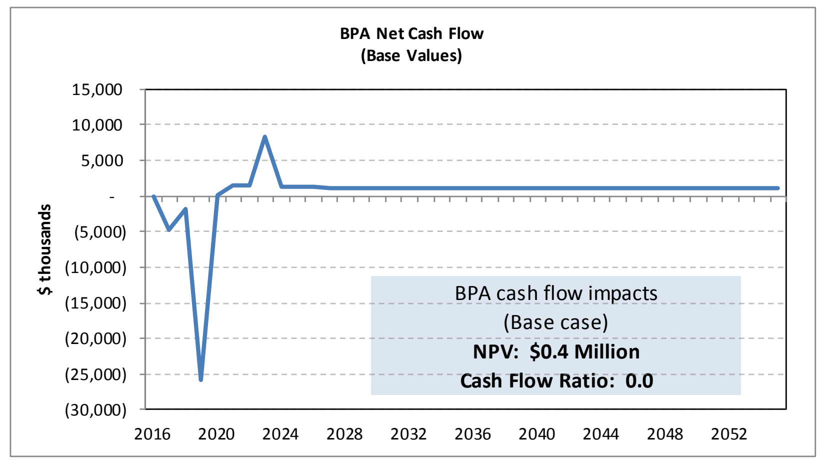


Net Economic Benefit Ratio: 0.25

For every dollar invested there is an net economic return of $0.25 (Expected value)

	10%	EV	90%
Investment Cost	26,530	30,197	34,093
Economic Benefits	33,304	37,768	43,153
Net Economic Benefits	1,960	7,571	13,395





Additional considerations:

The BBOs quantify the impact of safety incidents by assessing the monetary cost of litigation. However, there are many areas for safety improvements and the true risk and impact are difficult to capture. Further, this assessment does not ask the question of whether monetary costs are the most appropriate tool for capturing this level of risk. Additionally, the assessment does not factor in the impact of inflationary pressures on wages and vendor costs. When a general inflation factor is applied to the benefits over the 60 year life of the facility, the resultant NEBR is substantially higher.

Ross HMEM Garage Replacement

Spare Transformers at Wind Sites - Central Ferry Substation
Classification: Discretionary
Sponsoring Asset Category: Transmission

What is the proposed investment?

The proposed investment is to install a fourth 500 kV single phase transformer at Central Ferry substation (one of four to be installed) The investment improves reliability for wind generation customers served by this bank and brings the substation up to conformance with Transmission policy of installing a spare transformer at these wind substation sites. In 2005, wind generation availabiliy was not considered an issue for grid operations. Loss of wind generation due to transformer failure could be offset with other generation within the BPA BAA. Accordingly, a radial connection with the transformer as a single point of failure was deemed unacceptable. Generation customers integrated at these four substations were made aware of a potential 30 day outage due to transformer failure.

OP_CABRptText1

Why is this investment needed?

Transmission Services management has determined that the addition of a spare transformer at all 500/230kV BPA facilities for integrating wind projects is now BPA policy. A policy for future wind generation projects has been approved and will go into effect in the fall of 2013. There remains an outstanding issue of how to address needed spare transformer additions to 4 existing substations that only have 3 single phase transformers in place (Slatt, John Day, Rock Creek and Central Ferry).

What assumptions are behind the investment need?

OP_CABRptText2

Installation of these transformers would enable BPA to rotate each one of the 4 transformers out of service on a 10-year cycle, thereby extending their service lives, reducing long-term replacement costs, and lowering O&M costs.

OP_CABRptText3

What actions would be taken if this investment were not made?

The cost of lost generation may well be unacceptable to the wind project owners.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

The only technical alternative is to do nothing which adds considerable risk to the producer as well as to BPA.

OP_CABRptText5

Who would benefit from this investment?

Wind Generation owners

Timing and Costs of the Investment

(2016 dollars in thousands)

(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete													% of Investment			
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	that is expense	Low	Base	High
Oct-14	Sep-18	Jan-19	Mar-19	$4,000	$5,000	$6,400	$62	$186	$62	$5,890	$0	$0	$6,200	0%	30	45	70

What drives the investment costs to be low or high?

Low investment cost: on time delivery, use BPA labor; High investment cost: late delivery, use CMO labor

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$20	$25	$6
Present value:	$555	$716	$162

Benefits of the Investment

Benefit name	Benefit description	% of Total
		0%
		0%
		0%
		0.0%
		0%
		0%
		0%

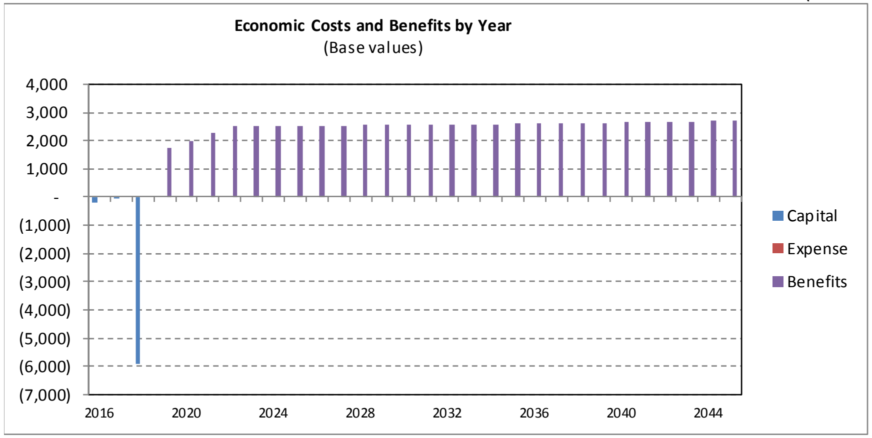
Spare Transformers at Wind Sites - Central Ferry Substation

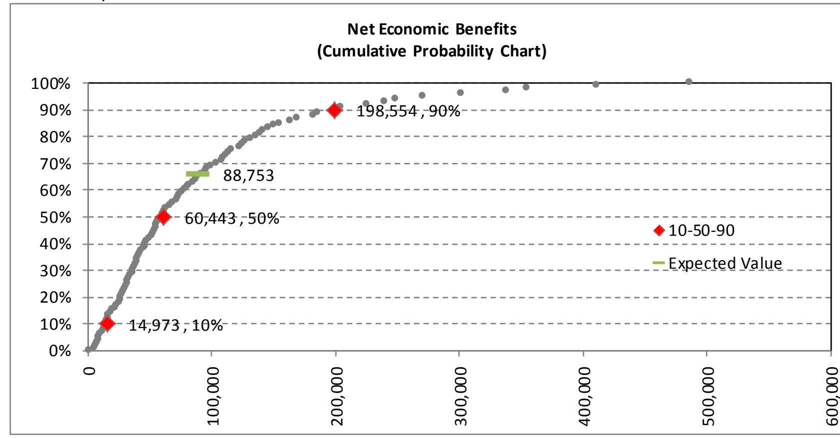
OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)

(AFUDC not included)

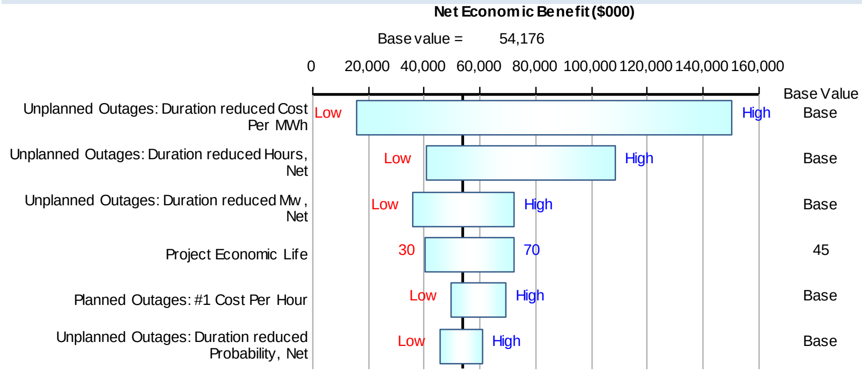


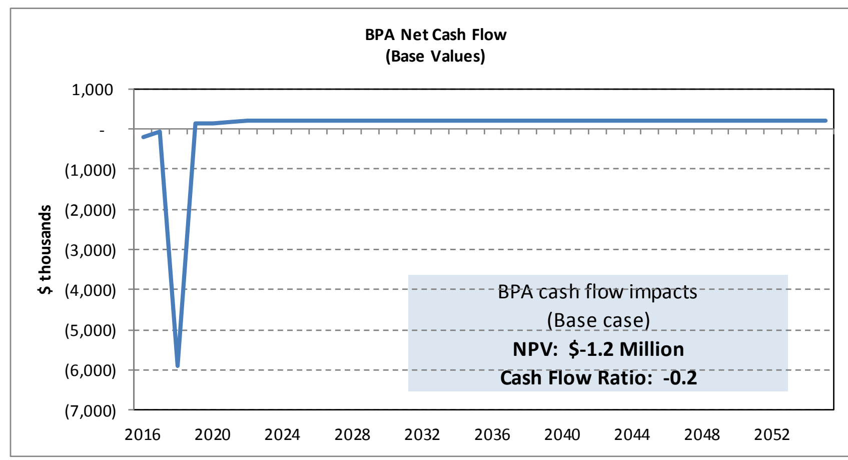


	10%	EV	90%
Investment Cost	4,638	5,896	7,422
Economic Benefits	21,135	94,649	203,444
Net Economic Benefits	14,973	88,753	197,720

Net Economic Benefit Ratio: 15.05

For every dollar invested, there is an net economic return of $15.05 (Expected value)





Additional considerations:

Spare Transformers at Wind Sites - John Day Substation
Classification: Discretionary
Sponsoring Asset Category: Transmission

What is the proposed investment?

The proposed investment is to install a fourth 500 kV single phase transformer at John Day substation (one of four to be installed) The investment improves reliability for wind generation customers served by this bank and brings the substation up to conformance with Transmission policy of installing a spare transformer at these wind substation sites. In 2005, wind generation availabiliy was not considered an issue for grid operations. Loss of wind generation due to transformer failure could be offset with other generation within the BPA BAA. Accordingly, a radial connection with the transformer as a single point of failure was deemed unacceptable. Generation customers integrated at these four substations were made aware of a potential 30 day outage due to transformer failure.

OP_CABRptText1

Why is this investment needed?

Transmission Services management has determined that the addition of a spare transformer at all 500/230kV BPA facilities for integrating wind projects is now BPA policy. A policy for future wind generation projects has been approved and will go into effect in the fall of 2013. There remains an outstanding issue of how to address needed spare transformer additions to 4 existing substations that only have 3 single phase transformers in place (Slatt, John Day, Rock Creek and Central Ferry).

What assumptions are behind the investment need?

OP_CABRptText2

Installation of these transformers would enable BPA to rotate each one of the 4 transformers out of service on a 10-year cycle, thereby extending their service lives, reducing long-term replacement costs, and lowering O&M costs.

OP_CABRptText3

What actions would be taken if this investment were not made?

The cost of lost generation may well be unacceptable to the wind project owners.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

The only technical alternative is to do nothing which adds considerable risk to the producer as well as to BPA.

OP_CABRptText5

Who would benefit from this investment?

Wind Generation owners

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete													% of Investment			
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	that is expense	Low	Base	High
Oct-14	Sep-17	Oct-17	Dec-17	$4,600	$4,700	$5,200	$175	$4,488	$1,107	$58	$0	$0	$5,828	0%	30	45	70

What drives the investment costs to be low or high?
Low investment cost: on time delivery, use BPA labor; High investment cost: late delivery, use CMO labor

OP_CABRptText7

How will asset O&M costs change with this investment?	Before Invest	After Invest	Change
Average annual	$20	$26	$6
Present value:	$571	$738	$167

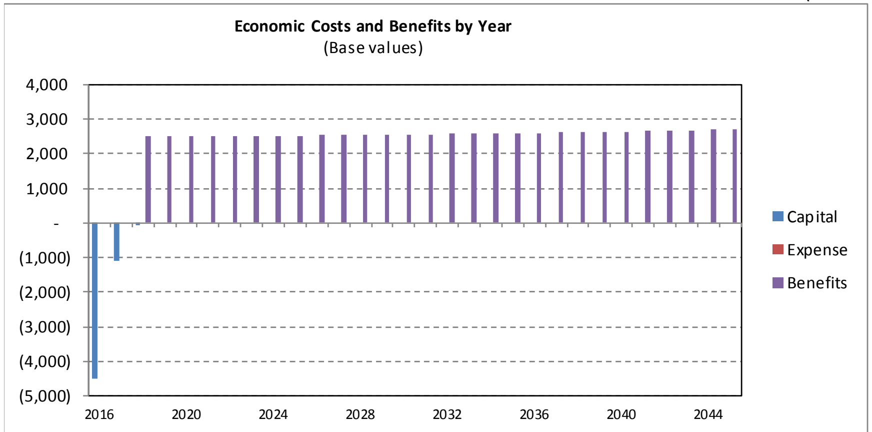
Benefits of the Investment

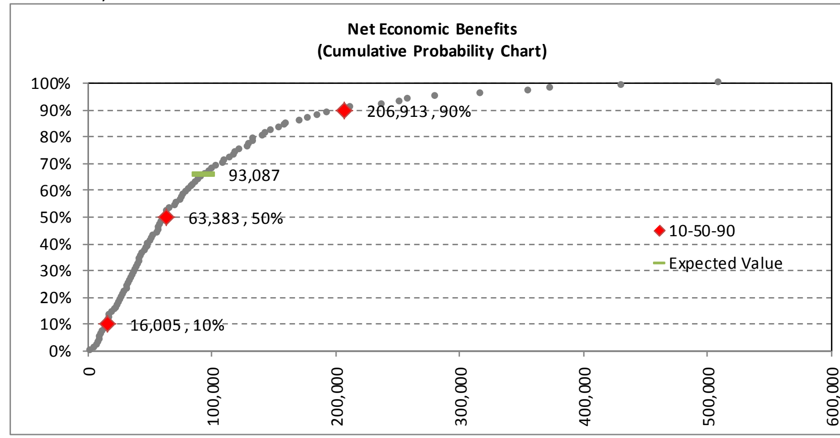
Benefit name	Benefit description	% of Total
System Reliability	Avoided cost of planned and unplanned outages including replacement power and emissions	97%
Ongoing Costs	Reduced O&M Costs	1%
Transformer Life	Increased life of transformer bank with 4th transformer	1%
Service Restoration Cost	Cost to restore service if a transformer were to fail	1.0%
		0%
		0%
		0%

Spare Transformers at Wind Sites - John Day Substation

OP_CABRptTable

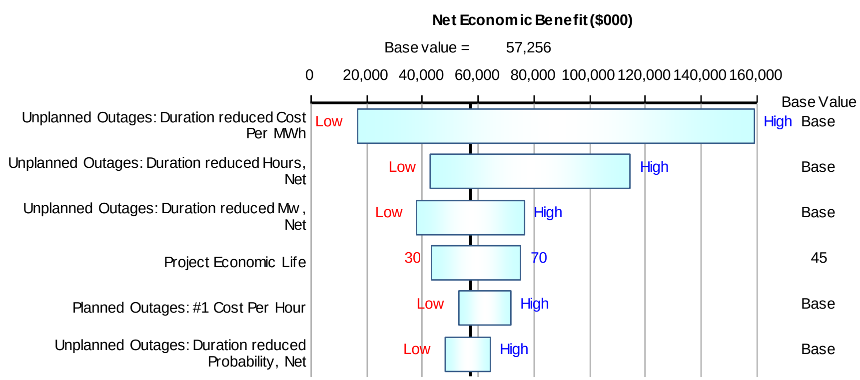
Net Economic Benefits and Cash Flows
(2016 dollars in thousands)
(AFUDC not included)

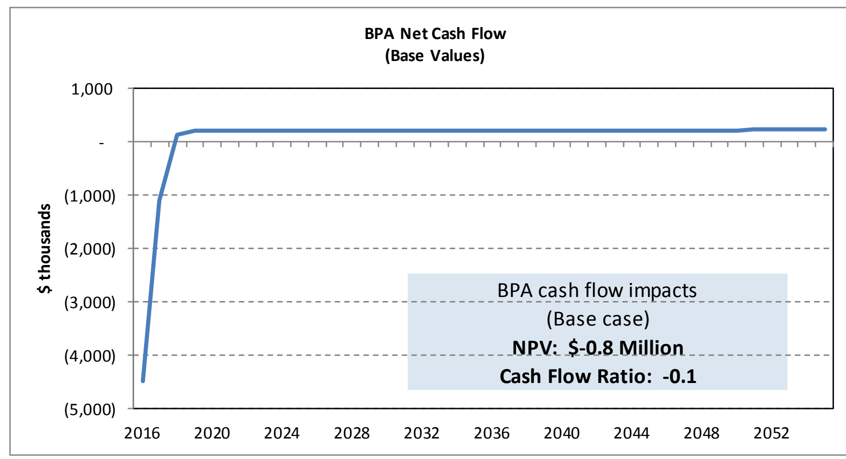




Net Economic Benefit Ratio: 16.23
For every dollar invested, there is an net economic return of $16.23 (Expected value)

	10%	EV	90%
Investment Cost	5,498	5,734	6,215
Economic Benefits	21,926	98,821	212,137
Net Economic Benefits	16,005	93,087	206,654





Additional considerations:

Spare Transformers at Wind Sites - Rock Creek Substation
Classification: Discretionary
Sponsoring Asset Category: Transmission

What is the proposed investment?

The proposed investment is to install a fourth 500 kV single phase transformer at Rock Creek substation (one of four to be installed) The investment improves reliability for wind generation customers served by this bank and brings the substation up to conformance with Transmission policy of installing a spare transformer at these wind substation sites. In 2005, wind generation availabiliy was not considered an issue for grid operations. Loss of wind generation due to transformer failure could be offset with other generation within the BPA BAA. Accordingly, a radial connection with the transformer as a single point of failure was deemed unacceptable. Generation customers integrated at these four substations were made aware of a potential 30 day outage due to transformer failure.

OP_CABRptText1

Why is this investment needed?

Transmission Services management has determined that the addition of a spare transformer at all 500/230kV BPA facilities for integrating wind projects is now BPA policy. A policy for future wind generation projects has been approved and will go into effect in the fall of 2013. There remains an outstanding issue of how to address needed spare transformer additions to 4 existing substations that only have 3 single phase transformers in place (Slatt, John Day, Rock Creek and Central Ferry).

What assumptions are behind the investment need?

OP_CABRptText2

Installation of these transformers would enable BPA to rotate each one of the 4 transformers out of service on a 10-year cycle, thereby extending their service lives, reducing long-term replacement costs, and lowering O&M costs.

OP_CABRptText3

What actions would be taken if this investment were not made?

The cost of lost generation may well be unacceptable to the wind project owners.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

The only technical alternative is to do nothing which adds considerable risk to the producer as well as to BPA.

OP_CABRptText5

Who would benefit from this investment?

Wind Generation owners

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete													% of Investment			
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	that is expense	Low	Base	High
Oct-14	Sep-17	Jan-18	Apr-18	$4,600	$4,668	$5,500	$174	$4,225	$116	$1,273	$0	$0	$5,788	0%	30	45	70

What drives the investment costs to be low or high?
Low investment cost: on time delivery, use BPA labor; High investment cost: late delivery, use CMO labor

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$20	$26	$6
Present value:	$571	$738	$167

Benefits of the Investment

Benefit name	Benefit description	% of Total
System Reliability	Avoided cost of planned and unplanned outages including replacement power and emissions	97%
Ongoing Costs	Reduced O&M Costs	1%
Transformer Life	Increased life of transformer bank with 4th transformer	1%
Service Restoration Cost	Cost to restore service if a transformer were to fail	1.0%
		0%
		0%
		0%

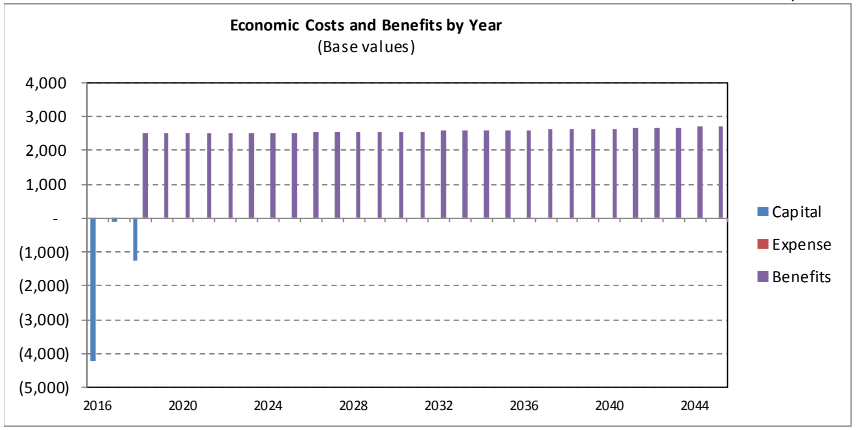
Spare Transformers at Wind Sites - Rock Creek Substation

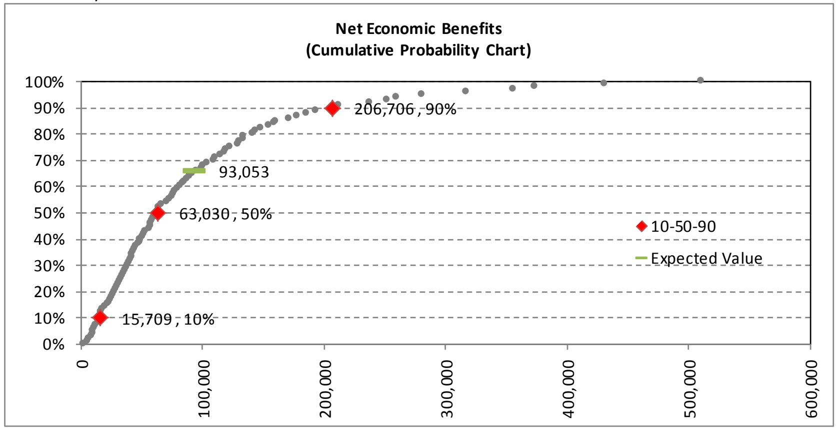
OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)

(AFUDC not included)

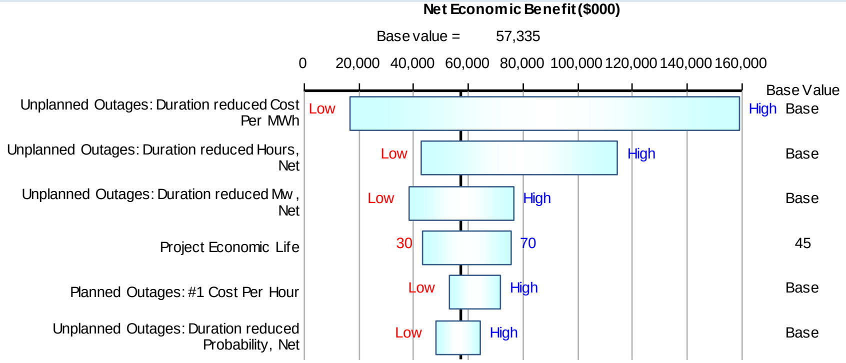


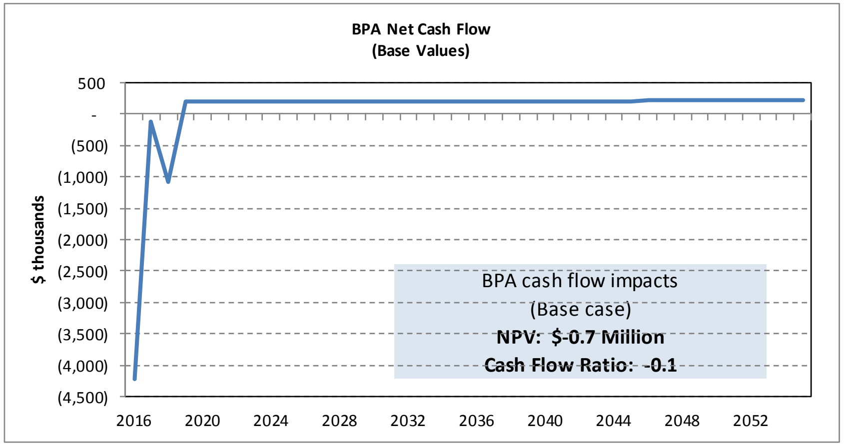


Net Economic Benefit Ratio: 16.13

For every dollar invested, there is an net economic return of $16.13 (Expected value)

	10%	EV	90%
Investment Cost	5,458	5,770	6,525
Economic Benefits	21,926	98,823	212,146
Net Economic Benefits	15,709	93,053	206,603





Additional considerations:

Spare Transformers at Wind Sites - Rock Creek Substation OP_CABRptText8

Spare Transformers at Wind Sites - Slatt Substation
Classification: Discretionary
Sponsoring Asset Category: Transmission

What is the proposed investment?

The proposed investment is to install a fourth 500 kV single phase transformer at Slatt substation (one of four to be installed) The investment improves reliability for wind generation customers served by this bank and brings the substation up to conformance with Transmission policy of installing a spare transformer at these wind substation sites. In 2005, wind generation availabiliy was not considered an issue for grid operations. Loss of wind generation due to transformer failure could be offset with other generation within the BPA BAA. Accordingly, a radial connection with the transformer as a single point of failure was deemed unacceptable. Generation customers integrated at these four substations were made aware of a potential 30 day outage due to transformer failure.

OP_CABRptText1

Why is this investment needed?

Transmission Services management has determined that the addition of a spare transformer at all 500/230kV BPA facilities for integrating wind projects is now BPA policy. A policy for future wind generation projects has been approved and will go into effect in the fall of 2013. There remains an outstanding issue of how to address needed spare transformer additions to 4 existing substations that only have 3 single phase transformers in place (Slatt, John Day, Rock Creek and Central Ferry).

What assumptions are behind the investment need?

OP_CABRptText2

Installation of these transformers would enable BPA to rotate each one of the 4 transformers out of service on a 10-year cycle, thereby extending their service lives, reducing long-term replacement costs, and lowering O&M costs.

OP_CABRptText3

What actions would be taken if this investment were not made?

The cost of lost generation may well be unacceptable to the wind project owners.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

The only technical alternative is to do nothing which adds considerable risk to the producer as well as to BPA.

OP_CABRptText5

Who would benefit from this investment?

Wind Generation owners

Spare Transformers at Wind Sites - Slatt Substation OP_CABRptText6

Timing and Costs of the Investment

(2016 dollars in thousands)

(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Oct-14	Jul-18	Oct-18	Mar-19	$5,000	$5,675	$6,400	$70	$0	$352	$6,615	$0	$0	$7,037	0%	30	45	70

What drives the investment costs to be low or high?

Low investment cost: on time delivery, use BPA labor; High investment cost: late delivery, use CMO labor

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$20	$25	$6
Present value:	$555	$716	$162

Benefits of the Investment

Benefit name	Benefit description	% of Total
System Reliability	Avoided cost of planned and unplanned outages including replacement power and emissions	97%
Ongoing Costs	Reduced O&M Costs	1%
Transformer Life	Increased life of transformer bank with 4th transformer	1%
Service Restoration Cost	Cost to restore service if a transformer were to fail	1.0%
		0%
		0%
		0%

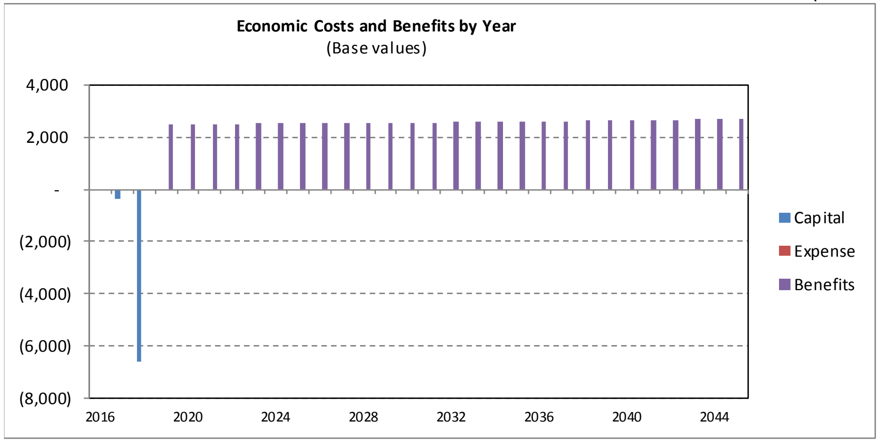
Spare Transformers at Wind Sites - Slatt Substation

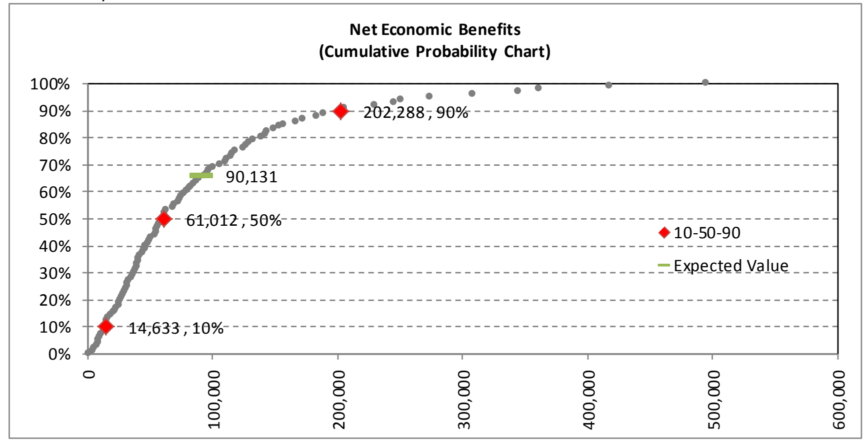
OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)

(AFUDC not included)

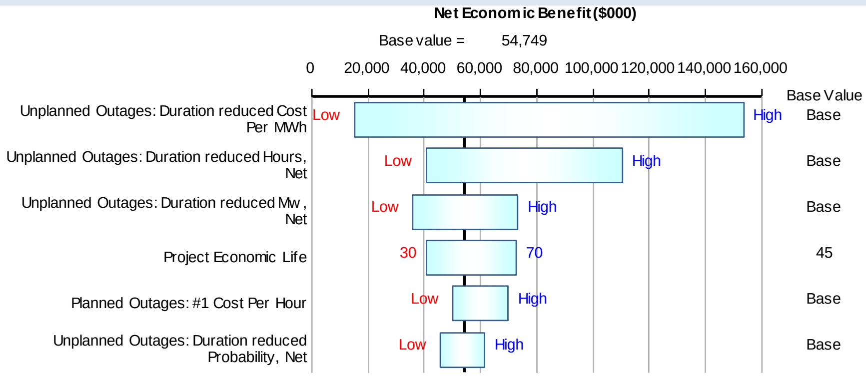


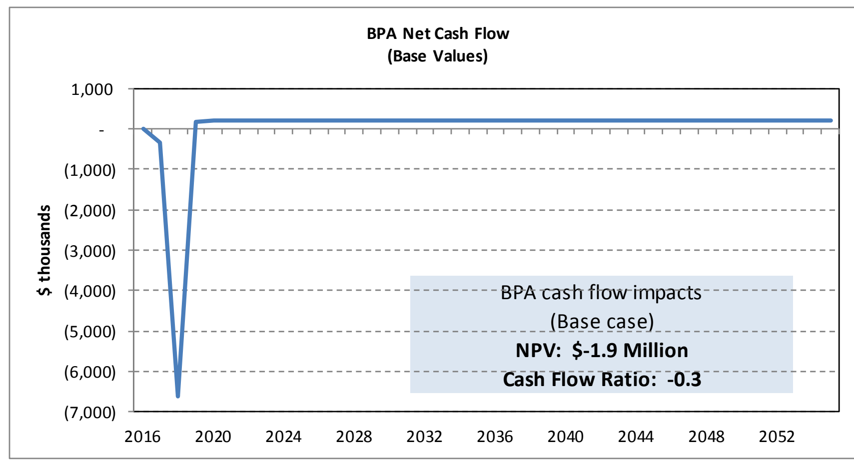


	10%	EV	90%
Investment Cost	5,794	6,570	7,417
Economic Benefits	21,530	96,701	206,917
Net Economic Benefits	14,633	90,131	199,546

Net Economic Benefit Ratio: 13.72

For every dollar invested, there is an net economic return of $13.72 (Expected value)





Additional considerations:

Sun Dial Land Acquisition
Classification: Discretionary
Sponsoring Asset Category: Transmission

What is the proposed investment?
Purchase lots 11 and 12 from Port of Portland. No improvements will be made to the bare land at this time, but would be held for future uses.

OP_CABRptText1

Why is this investment needed?
At Troutdale there is currently inadequate surrounding land owned by BPA to accommodate future expansion needs. Future expansion will eventually be needed due to local growth as well as bring energy from the North and East through this area. Should I-5 Reinforcement project be built it would need land near Troutdale substation to accommodate a 500 kV substation.

What assumptions are behind the investment need?

OP_CABRptText2

BPA has been in discussions with the Port of Portland over the past 2 years regarding the sale/acquisition of lots 11 and 12 in the area near Troutdale substation. Part of the sites could be used to expand substation facilities in the area as needed. The Port of Portland is reclaiming one of the lots as a wetland and this lot would be part of the combined deal for it should go through.

OP_CABRptText3

What actions would be taken if this investment were not made?
Future expansion at Troutdale would require a land acquisition in surrounding area.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

OP_CABRptText5

Who would benefit from this investment?

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete																
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	% of Investment that is expense	Low	Base	High
Jun-16	Sep-16	Jan-17	Sep-17	$6,000	$9,000	$15,000	$0	$90	$8,910	$0	$0	$0	$9,000	0%	50	50	50

What drives the investment costs to be low or high?

Uncertainty of the appraised value of the land.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$0	$0
Present value:	$0	$0	$0

Sun Dial Land Acquisition

Vegetation Management System (VMS)
Classification: Discretionary
Sponsoring Asset Category: IT

What is the proposed investment?

The investment will implement a purpose-built vegetation management software package selected from one of the many available in the marketplace. Key components that are available in many of these product lines include: geospatial work scheduling and tracking, support for multiple business process workflows, mobile support for use in the field, paperless invoicing, and out-of-the-box reporting. The solution will be deployed as a BPA-hosted commercial off-the-shelf system. The system will be externally facing to permit utilization by BPA's contracted maintenance and inspection vendors.

OP_CABRptText1

Why is this investment needed?

The Vegetation Management Program uses a combination of Excel spreadsheets, SharePoint lists, a "home grown" Vegetation Corrective Maintenance System (VCMS), eGIS, BES/Asset Suite and manual processes to:
- Monitor corridor health (identify, manage and track transmission corridor/rights-of-way profile information)
- Manage contracts (create SOWs, selected vendors and oversee/inspect their work)
- Plan and execute work (Plan, schedule, execute and track scheduled and corrective maintenance)
- Produce reports (capture and integrate data, perform cost and other analyses, and prepare, validate, and distribute compliance and other reports.

These processes are inadequate, unintegrated and inefficient, and they result in unnecessarily high labor and other costs, sub-optimal prioritization of work, and avoidable outage and regulatory sanction risks.

What assumptions are behind the investment need? OP_CABRptText2

BPA Transmission will implement process reforms consistent with the leading practice IVM (Integrated Vegetation Management) system, as called for in the Transmission Lines/ROW Asset Strategy. Under the IVM, managers set objectives, identify compatible and incompatible vegetation, consider action thresholds, and evaluate, select and implement the most appropriate control method or methods to achieve set objectives. The choice of control method or methods should be based on the environmental impact and anticipated effectiveness along with site characteristics, security, economics, current land use and other factors. Purpose-built applications are available in the market place which require minimal integration with BPA's environment to implement.

OP_CABRptText3

What actions would we take if this investment were not made?

VCMS would continue to be used to capture a portion of the observed hazards (from annual ground and aerial patrols) with potential future options to extend this custom-built interim solution. The existing method of utilizing Excel spread sheets to build and track work plans would continue with an option to extend the TAS suite to capture field activities. eGIS Livemap and supporting ESRI products would be used to display observations by Danger Tree crew and LiDAR data in a map visualization. Third party vendor inspections could be manually imported by GIS Analysts to the eGIS system for vendors that have GIS software packages. New reports and eGIS database structures could be developed to provide tabular tracking of scheduled vegetation maintenance and inspection activities (with overlaps to the spread sheet approach). Risky, labor-intensive processes would largely continue, potentially exposing BPA to reliability issues and regulatory sanctions.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

The status quo path, rejected because it is inadequate, unintegrated and inefficient, and it would result in unnecessarily high labor and other costs, sub-optimal prioritization of work, and avoidable outage and regulatory sanction risks.

OP_CABRptText5

Who would benefit from this investment?

Vegetation Management Program - TFVB, Real Property Services - TER, Asset Management and Engineering Applications Support - JST. Land owners and regulatory bodies, including WECC, EPA, and USFWS, may be secondary beneficiaries of the investment. Transmission customers may also benefit from reduced transmission derates and outages.

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete													% of Investment			
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	that is expense	Low	Base	High
Mar-14	Dec-16	Mar-17	Jun-17	$2,711	$2,911	$3,319	$1,593	$1,981	$726	$0	$0	$1,593	$4,300	32%	3	7	10

What drives the investment costs to be low or high?

The low cost scenario assumes that the software that is selected is relatively simple and straightforward to implement to support the vegetation management function. This scenario includes adoption of product-provided workflows, shared cloud environments, and a cut-over to the business function within an annual cycle. The high cost scenario is the inverse, namely ,the product requires more vendor-provided customization and the timelines run on the high end of estimates due to cut-over or implementation needs.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$69	$159	$90
Present value	$430	$991	$561

Benefits of the investment

Benefit name	Benefit description	% of Total
Avoided labor costs -- VM program and planning functions	The VMS will automate processes and make them more effective and efficient. This will reduce labor hours and costs to perform key vegetation management functions: Monitor corridor health, manage contracts, plan and execute work, and produce reports	22%
Avoided transportation/travel costs	The VMS will help reduce the number of trips in the field to inspect/monitor the health of corridors and oversee contractor performance. This is because (1) inspections will be better targeted and bundled with redundancies reduced and (2) work requirements for contractors will be more specific, better targeted, and consistent. Further, heavier reliance will be placed on aerial inspections, which are lower cost. By reducing the number of trips, fuel costs and other vehicular costs will be reduced. (Staff travel time will also be reduced, but these labor savings are captured in the benefit row above.)	1%
Reduced pricing – vendor contracts	Higher quality data and Improved access will enable BPA to prepare clearer, more specific statements of work with fewer change orders. This will reduce uncertainty from a vendor's perspective, and should lead to a reduction in risk premiums that vendors add to their contract bids . It will also enhance BPA's ability to evaluate the cost effectiveness of contract bids and oversee contractor performance, thereby improving "bang for the buck."	41%
Avoided regulatory sanctions	Violations of standards issued by WECC, EPA, USFWS, and other regulatory bodies can lead to mandates for corrective action. For example, in 2008, violations led to high cost, multi-year requirements imposed by WECC. As the quality and accessibility of data improves and as planning, prioritization, and execution of work improves, compliance risks will be reduced along with the risk of sanction-able violations	13%
Public relations	Efficiency in communications and transparency with the public (landowners, the press etc.) will reduce labor time to address public relations issues and repair reputational damage	0%
On-going Costs	Operations and Maintenance cost to operate new VMS system. This benefit is negative because there are no such costs today because no software system exists, and the VMS will require on-oing maintenance and support.	-8%
Avoided unplanned outages	The likelihood and consequence of unplanned outages will go down as the quality and accessibility of vegetation management data improves and as planning, prioritization, and execution of monitoring and clearing work improves. This in turn leads to reduced risk of unplanned outages and associated BPA costs, such as pricing premiums for emergency labor time and equipment orders.	30%

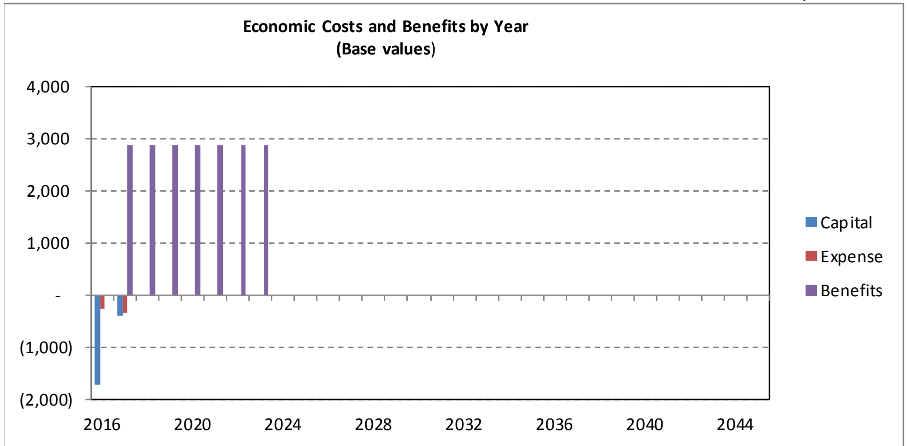
Vegetation Management System (VMS)

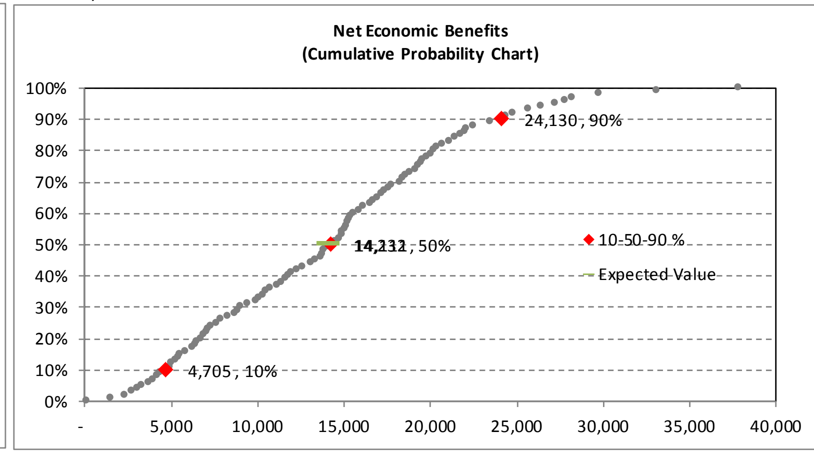
OP_CABRptTable

Net Economic Benefits and Cash Flows

(2016 dollars in thousands)

(AFUDC not included)

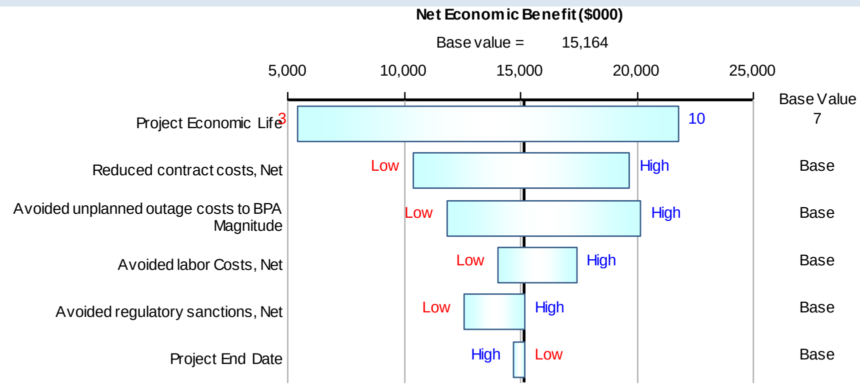


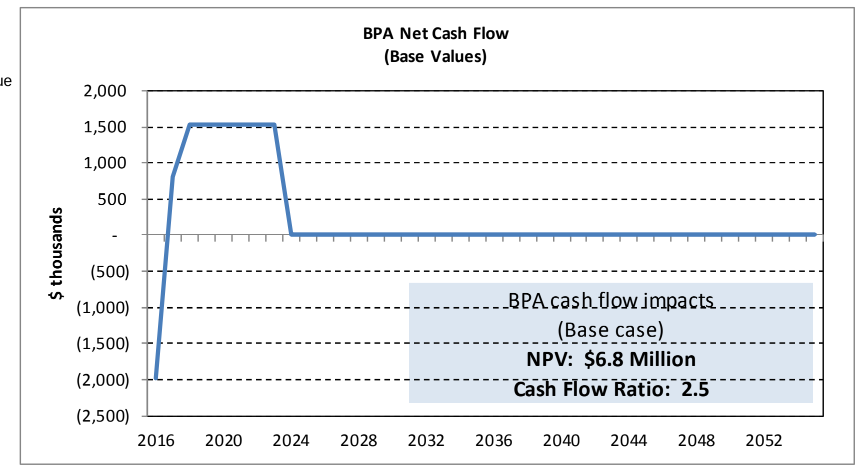


Net Economic Benefit Ratio: 5.19

For every dollar invested there is an economic return of $5.19 (Expected Value)

	10%	EV	90%
Investment Cost	2,529	2,719	2,978
Economic Benefits	7,472	16,830	26,814
Net Economic Benefits	4,705	14,111	24,062





Additional considerations:

Vegetation Management System (VMS)

OP_CABRptText8

Treaty/Non-Treaty Application
Classification: Policy Commitment
Sponsoring Asset Category: IT

What is the proposed investment?

Sytec developed the current TNT application for BC Hydro. This gives them unique knowledge of the functionality required by BPA, which other software developers would not possess. To confirm this, as part of the System Planning phase of the project, BPA and Sytec collaborated on an eight week detailed design and planning exercise. This resulted in the completion of a System Design Specification, a System Development Plan, a Quality Assurance Plan and an Implementation Plan for a system that delivers the goals stated above. In addition, Sytec's quality of service and product has been excellent without commensurate additional costs to the Government. There have been no contractor delays and Sytec has delivered contract requirements based on the agreed upon time schedule to date.

OP_CABRptText1

Why is this investment needed?

Bonneville Power Administration determines megawatt and financial payments under the new (April 2012) Non-Treaty Storage Agreement (NTSA). In the first year (FY12) of the contract BPA made a payment to BC Hydro of $41.7 million for the BC Hydro share of benefits under the agreement. This payment represented the full federal payment, a portion of which was paid by Slice customers though the Slice true-up. Annual payments to either party in subsequent years have ranged from $19 million to $4 million. Payments are determined using a complex set of rules, data, and calculations. Related information, both treaty and non-treaty, and payment determinations are agreed with BC Hydro on a regular basis throughout the agreement year, resulting in a payment to either party at the end of the agreement year.

Recently-signed Treaty agreements are structured similarly with expected financial payments from one entity to the other in the $3 to $20 million dollar range annually. In addition, as part of forecasting BPA makes a "Treaty" request each week for water at the US/Canadian border, based on a variety of factors, and this request has implications on project operations and trading.

What assumptions are behind the investment need?

OP_CABRptText2

In April 2012, BPA and BC Hydro executed a long-term contract for coordinated use of up to 5 MAF of additional reservoir storage in Canada through September 15, 2024 (2012 NTSA). In the first year of the contract BPA made a payment to BC Hydro of $41.7 million for the BC Hydro share of benefits under the agreement. This payment represented the full federal payment, a portion of which will be paid by Slice customers though the Slice true-up. Accounting for this contract affects both Slice and non-Slice customers as well as Pacific Northwest Coordination Agreement (PNCA) Parties. To date under the 2012 NTSA, BPA has paid BC Hydro $65.0 million and BC Hydro has paid BPA $14.8 million.

OP_CABRptText3

What actions would we take if this investment were not made?

The business is currently using spreadsheets to track and manage the Treaty and Non-Treaty accounting and forecasting as well as the usable h/k calculation. The business is currently not using multi-trace forecasting in the weekly treaty negotiations and NTS decision framework process. Without the application described above there will still be business costs to build missing functionality in the spreadsheets as well as the cost of continued manual processes.

The current spreadsheets have numerous drawbacks:

- Existing Excel spreadsheets would continue to be used which is inconsistent with management objectives in spreadsheet management.
- Additional staff time would be required to include spreadsheet implementation of portions of the NTSA and PNCA contracts that have not been used to date.

OP_CABRptText4

What investment alternatives were considered and why are they not recommended?

The status quo of continuing the manual state of managing and accessing agency information assets - including, in some cases, the lack of ability to produce data artifacts - was considered. It is not recommended because it: 1) does not provide compliance; and 2) exposes BPA to litigation, audit, and sanctions risk, and (3) requires excessive labor hours to implement. Software as a Service (SaaS) and Commercial Off the Shelf (COTS) solutions were considered. SaaS was rejected due to data constraints. COTS was selected as the best alternative for BPA.

OP_CABRptText5

Who would benefit from this investment?

Timing and Costs of the Investment
(2016 dollars in thousands)
(AFUDC not included in capital costs)

Timing of Investment				Range of Investment Costs (Direct Capital Costs)			Fiscal Year Flow of Investment Expenditures (Base) (Direct Capital Cost plus Indirects/Overheads and Expense)							Cap/Exp Split	Economic Life of Assets		
	Complete													% of Investment			
Start	Early	Base	Late	Low	Base	High	Pre-2016	2016	2017	2018	2019	Post 2019	Total	that is expense	Low	Base	High
Oct-13	May-18	May-18	Oct-18	$3,440	$3,600	$3,920	$766	$1,011	$972	$1,029	$0	$0	$3,779	5%	8	10	20

What drives the investment costs to be low or high?

Phase 2 UDM project cost would be reduced if implementation is less complex than expected, resulting in reduced BPA labor hours and costs. Phase 3 SDM project cost would be reduced if a module from the UDM vendor is acceptable to manage structured data.

Phase 2 UDM project cost would increase if implementation is more complex than expected, resulting in increased BPA labor hours and costs. Phase 3 SDM project cost would increase if a separate solution is required to manage structured data.

OP_CABRptText7

How will asset O&M costs change with this investment?

	Before Invest	After Invest	Change
Average annual	$0	$74	$74
Present value	$0	$595	$595

Treaty/Non-Treaty Application