BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-17________

EXH. SJK-4

SCOTT J. KINNEY

REPRESENTING AVISTA CORPORATION

Generation / Production Capital Projects - Index of Business Case Justification Narratives

* The transfers to plant associated with this business case represent investment of four thousand dollars ($4,000) associated with trailing charges following the completion of the project, which is not unusual for this type of major project. Given that the project is complete, with the exception of these trailing charges, a business case justification narrative in the new format was not completed for this project.

Automation Replacement

1 GENERAL INFORMATION

Requested Spend Amount	$650,000.00
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Kristina Newhouse
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Customer Service Quality & Reliability

1.1 Steering Committee or Advisory Group Information

The controls engineering team identified the need to address the risk of aging and failing control equipment. The Distributed Control Systems (DCS) and Programmable Logic Controllers (PLC) are aging and are introducing an increase in hardware and software failures. Discussions with the Director of GPSS, the Manager of Operations Analytics, the Electrical Engineering Manager, and the Protection Control Meter Technician Foreman concluded that a planned replacement program was needed.

The controls engineering manager will provide ongoing oversight and monthly tracking of the ongoing work within the program. The advisory group for ongoing vetting includes the Director of GPSS, the Controls Engineering Manager, the Protection Control Meter Technician Foreman, the Manager of Hydro Operations and Maintenance, and the Manager of Thermal Operations and Maintenance.

2 BUSINESS PROBLEM

The major driver for the Automation Replacement business case is Reliability. This program aligns with Avista's Safe & Reliable Infrastructure strategy. Upgrading our control systems within our generating facilities allows us to provide reliable energy. The Distributed Controls Systems (DCS) and Programmable Logic Controllers (PLC) are used to control and monitor Avista's generating units as well as each generating facility. For many facilities the operation of the generating units is performed remotely with the use of the DCSs and the PLCs. These aging devices use unsupported operating systems and modules that are no longer available. Failing software and hardware introduces risk and limits Avista's ability to operate generating facilities reliably.

The DCS and PLC work is needed now to reduce the higher risk of failure due to the aging equipment. The DCSs are no longer supported and spare modules are limited. The modules in service have a high risk of failure as they are over 20 years old. The computer drivers that are needed to communicate to the DCSs will not fit in new computers with Windows 10 operating systems. This creates a Cyber Security issue.

The software needed to view and modify the logic programs only runs on Windows 95. Avista has a very limited supply of Windows 95 laptops and they also continue to fail.

Replacing aging DCSs and PLCs will reduce unexpected plant outages that require emergency repair with like equipment. A planned approach will allow engineers and technicians to update logic programs more effectively and replace hardware with current standards.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Option 1 - Upgrade DCS and PLCs	$6.5M	1/2017	12/2025
Option 2 - Spare Parts Refurbishment / Do nothing	$100k/year	1/2017	NA
Option 3 - Software Upgrade	$2.5M	1/2017	12/2025

Option 1 is to replace all aging DCSs and PLCs proactively on a schedule that takes into account resources and outage availability. This option addresses aging hardware and software concerns as well as the cyber security vulnerabilities. Additional resources are required in order to maintain a schedule and consistently meet the objectives. Engineering will require a designer to develop new logic programs and designs for installations. The Protection Control Meter Shop will need a resource to install and commission the PLC programs.

Option 2 is to maintain existing Bailey DCSs and Modicon PLCs as we currently do today. This includes replacing modules as they fail with old spare parts or refurbish third party parts. Maintaining spare parts allows us to continue using existing infrastructure and logic programs but it does not resolve the long term issue which is aging equipment that will eventually no longer be available. The risk of outages at undesirable times to replace failed parts becomes more likely the longer the aging hardware is in service. This alternative also does not resolve the issue with computers that have unsupported operating systems and are considered a cyber-security risk.

Option 3 is to upgrade software on the DCSs and PLCs. This would include replacing each system's software that runs on Windows 95 and Windows XP with a separate software for each platform that runs on Windows 7. This will mitigate the software and cyber security issue but not the aging hardware issue. Outages would be required and the new logic programs would need to be rewritten and fully commissioned. Upgrading the Bailey software and the Modicon software do not align with our standard PLC platform that our engineers and technicians are trained on. This would introduce two new software applications. Efficiency to troubleshoot and resolve issues in a timely manner could be impacted.

Option 1 is the proposed option because it addresses the issues with aging hardware and software and it resolves the cyber security vulnerabilities. This option addresses the identified issues in a more controlled and planned manner where designs can be well thought out and plant outages for construction can be scheduled and ideally limited. The requested spend amount is based on Option 1 and takes into account resources needed to perform designs and installations. Is also takes into consideration feasibility of plant outages as projects are spread out over time.

See attached timeline titled *Timeline Estimate - Automation Replacement Business Case.pdf*

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Automation Replacement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Kristina Newhouse Date: 4/17/2017
Print Name: Kristina Newhouse
Title: Controls Engineering Manager
Role: Business Case Owner

Signature: Date: 4/19/2017
Print Name: Andrew Vickers
Title: Director GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Kristina Newhouse	04/05/2017	Andy Vickers	04/11/2017	Initial version

Template Version: 03/07/2017

Cabinet Gorge Automation

1 GENERAL INFORMATION

Requested Spend Amount	$2,941,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsors	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Investment Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

As generating plants are managed by the Generation, Production, and Substation support group, they provide energy and other services used by Power Supply. The steering committee for this project includes members from both groups: Director Power Supply; Director GPSS; Manager Hydro Ops and Manager Project Delivery. This team receives monthly project status updates but meets only in the event that a decision is needed.

The project/stakeholder team meets on a more regular basis (at least monthly) to work on the project's scope and planning. The project/stakeholder team is comprised of representatives from the various engineering groups (electrical, controls, mechanical) and plant operations.

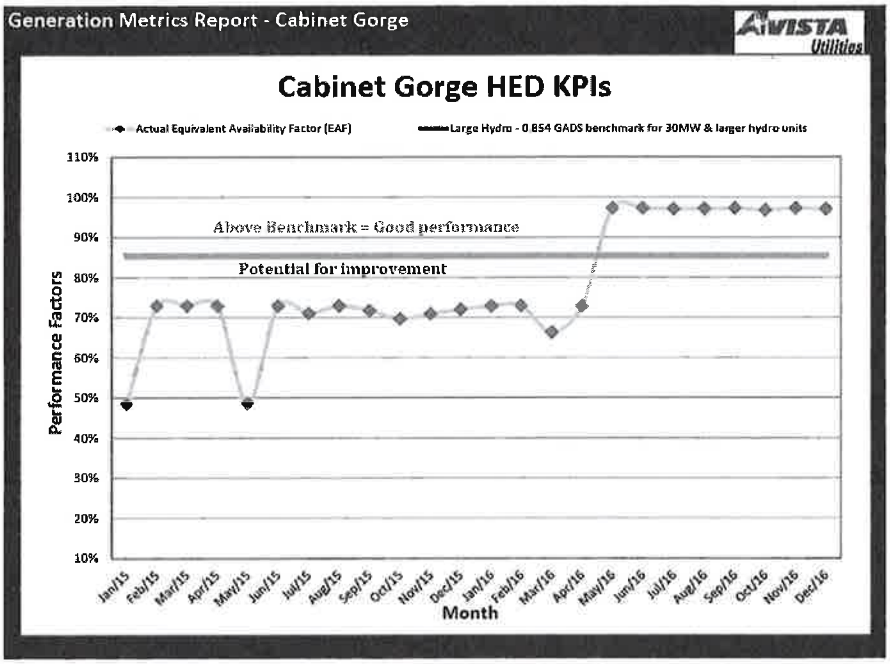
2 BUSINESS PROBLEM

This plant was designed for base load operation. Today, Cabinet Gorge is called on to not only provide load, but to quickly change output in response to the variability of wind generation, to adjust to changing customer loads, and other regulating services needed to balance the system load requirements and assure transmission reliability. The controls necessary to respond to these new demands include speed controllers (governors), voltage controls (automatic voltage regulator a.k.a. AVR), primary unit control system (i.e. PLC), and the protective relay system. In addition to reducing unplanned outages, these systems will provide the ability for Avista to maximize these services from within the pool of its own assets on behalf of its customers rather than having to procure them from other providers.

As part of the designated “Regulating Hydro” class of assets. The key metric for these plants is their Equivalent Availability Factor or EAF.

Equivalent Availability Factor (EAF) measures the amount of time that the Unit is able to produce electricity in a certain period, divided by the amount of time in that period. In this case, Cabinet Gorge has averaged below 85% EAF for the twelve month rolling period ending September 2016. The internal company target for this measure is 85%

Chart 1 – Equivalent Availability Factor



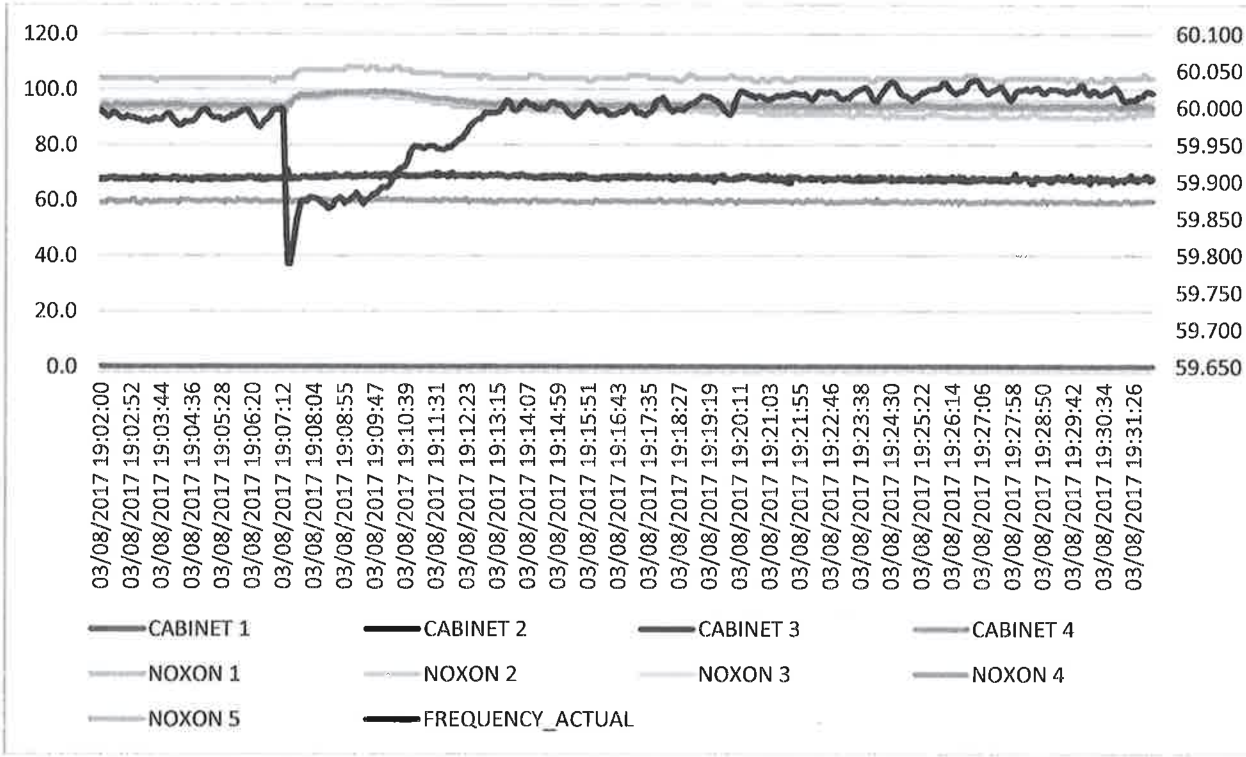
Some of the outages that cause the EAF to fall below the target include forced and maintenance outages associated with the control and protection systems described. Some recent events captured are attached to this document for reference[1].

An additional problem with the existing speed controls (governors) is the lack of response in a system frequency event. The graph below shows a significant frequency “excursion” (the dark blue line) and the response of the machines at Noxon Rapids HED to this excursion. Those are the lines that move upward on the top of the chart. The response of the Cabinet Units is shown in the lines in the

[1] See “18 Maximo Work Orders related to CG Controls.”

middle of the chart should have bumped up like the Noxon, but instead were non-responsive.

Chart 2 – Lack of Frequency Response



A similar chart showing voltage control issues at Cabinet Gorge can be found in Appendix A.

There are several NERC Reliability standards against which the existing equipment performs at a sub-standard level. One of these standards involves frequency response as describe above. The related NERC standards are attached to this document along with some technical explanation if more information is needed.

Last, there have been several unit outages that were specifically taken to address problems associated with the existing control and protection equipment. This equipment is at the end of its intended life and there is an increased likelihood of forced outages and subsequent loss of revenue and reliability. More details of these events are can be found in the attached "18 Maximo Work Orders related to CG Controls" document.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing / Continue to Repair	$0	ongoing	ongoing
Replace Unit Control, Monitoring, and Protection Systems	$2,136,194	12/2015	12/2018
Mechanical, Controls, Electrical upgrades and Stator Re-wedging	$2,936,194	12/2015	12/2018

Avista's Safe & Reliable Infrastructure strategic initiative seeks to leverage technology and innovative products and services offered to existing and new customers. The work proposed for Cabinet Gorge will include equipment and component replacement geared at increasing reliability and unit control/monitoring. Customers benefit in that it will allow Avista to economically optimize an existing asset to provide energy and other energy related products.

To accomplish project objectives to improve unit response, operating flexibility, and reliability, the following components will be considered: governor and governor controls, generator excitation system and AVR, protective relays, and unit controls. The extended outage will provide an opportunity to address other issues including, insulating the generator housing roof, cooling water upgrade, unit flow meter and other items to improve overall reliability. The objective is to ensure system compatibility with current standards and improve system reliability.

Do Nothing / Continue to Repair: While the generator is capable of producing energy with existing systems, the present equipment does not provide the system support abilities needed to meet today's requirements (see graph above). This solution requires maintenance of old systems that are no longer supported by the original manufacturer and there is some question on parts availability. Additionally, trained personnel available to work on these older systems are becoming scarce and formal training is no longer available. For reasons of obsolescence, inadequate system performance, and increasing maintenance demands, this option is not the preferred option.

Replace Unit Control, Monitoring, and Protection Systems: In addition to addressing issues of obsolescence and increased likelihood of unplanned outages, replacement of these key systems addresses the performance needs to work with the new dynamics of the systems today. This includes integration of intermittent resources, reserves, frequency and voltage response, and the ability to adapt these controls and protection devices as the larger grid continues to evolve.

Installation of new controls and protection will also provide increased visibility into the systems allowing better remote monitoring and troubleshooting. New systems are also configured so compliance with NERC standards is much easier to achieve. As this option addresses the primary issues, this is considered the minimal preferred option.

Mechanical, Controls, Electrical upgrades and Stator Re-wedging: This option is the same as the *Replace Unit Controls, Monitoring, and Protection Systems* described above except this also includes addressing additional items related to the reliability of the generating unit. This may include replacing the insulation system on the generator rotor, re-wedging the generator stator, replacing and updating auxiliary system motor controls, and other items identified as necessary to both extend the life of the asset and improve the reliability. This option would allow for work that would be necessary in the near future to be performed now therefore avoiding future outages and improving the near and long term reliability of the units. While this is the preferred option, it cannot be selected at this time due to the gantry crane's limitations[2].

Program Cash Flows

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ -	$ -	$ -	$ -
2013	$ -	$ -	$ -	$ -
2014		$ -	$ -	$ -
2015	$ 13,025	$ -	$ -	$ 30,000
2016	$ 316,000	$ -	$ -	$ 316,000
2017	$ 1,561,000	$ -	$ -	$ 1,561,000
2018	$ 532,000			$ 532,000
Total	$ 2,422,025	$ -	$ -	$ 2,439,000

[2] The gantry crane is needed to pick the rotor in order to perform the re-wedging work. The gantry crane is in a state of disrepair which is being addressed by a separate business case.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Cabinet Gorge Automation Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 20170417
Print Name: JACOB REIDT
Title: MGR CONTRACTS & PM
Role: Business Case Owner

Signature: Date: 4/19/2017
Print Name: Andrew Vickers
Title: Director GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Terri Echegoyen	04/14/17	Steve Wenke	04/14/17	Initial version

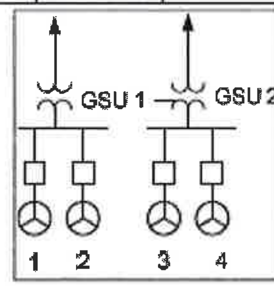
Template Version: 03/07/2017

APPENDIX A

AVISTA Utilities

Page 1 of 1

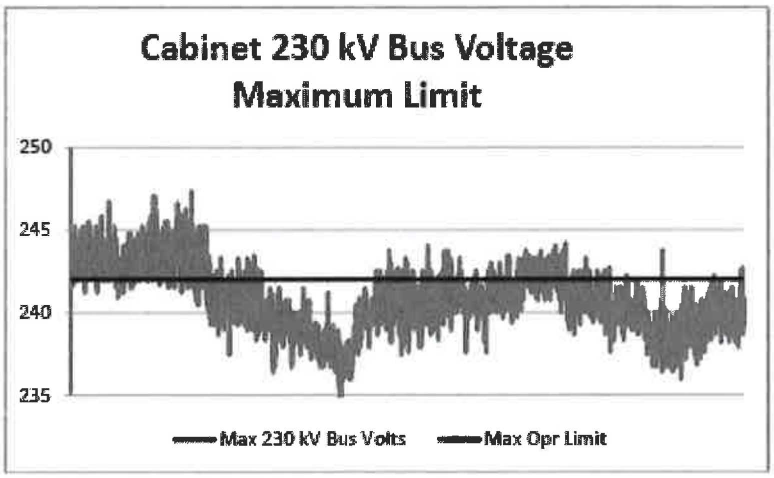
Project:	Cabinet Gorge HED - 230 kV Bus			Date:	03/29/17
Subject:	Bus Operating Voltage Analysis			By:	SEW
				Rev:	1
Proj No.:	09801545	Task:	535000	Ck'd:	

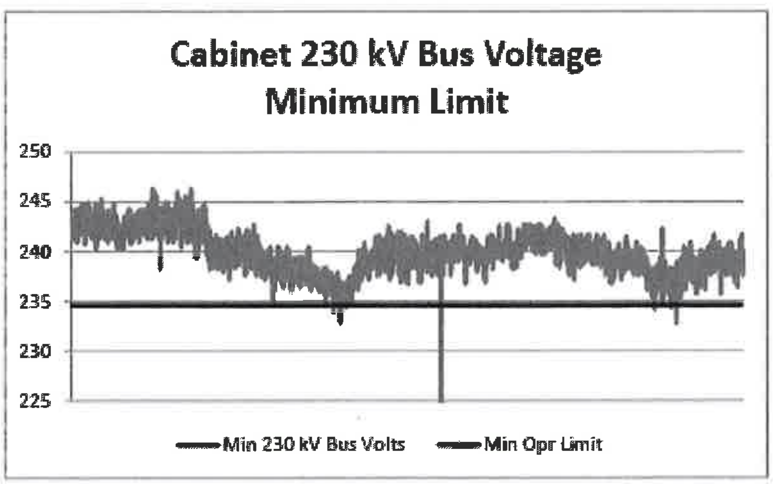


Generating Units Connected
Units 3 and 4

	from:	to:
Period Covered:	1/1/2016	12/31/2016

Number of Hours Voltage Exceeded Max Limits:	2275	hrs
Number of Hours Voltage Exceeded Min Limits:	32	hrs





Printed: 3/29/2017
Q:\G&P Files\Budget\Capital Budget\2017 Capital Budget\Cabinet Automation\Cabinet Voltage Schedule Report.xlsx

Cabinet Gorge Station Service

1 GENERAL INFORMATION

Requested Spend Amount	$4,275,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsors	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Investment Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The advisory group for this project consists of members from the Generation Production and Substation support department including: Director – GPSS, Manager Hydro Operations & Maintenance and Manager Electrical Engineering. Steering committee members receive monthly project status update reports but are convened only in the event of a decision point.

The project/stakeholder team meets on a more regular basis (at least monthly) to work on the project's scope and planning. The project/stakeholder team is comprised of representatives from the various engineering groups (electrical, controls, mechanical) and operations.

2 BUSINESS PROBLEM

All generation facilities require Station Service to provide electric power to the plant. Station Service components include Transformers, Power Centers, Motor Control Centers, Load Centers, Emergency Load Centers and various breakers. Station Service is an elaborate system with multiple built-in redundancies designed to protect the plant's electrical operation.

The Cabinet Gorge Station Service equipment is original from 1951. The station service is a typical redundant Main-Tie-Main Service with some components added over time to accommodate changes to the Units and Balance of Plant needs. The Main-Tie-Main has multiple power sources which provides various switching alternative to bypass systems so that power is never lost. Station Service transformers no longer have the capacity to provide the needed load and could be subject to overload. The current Motor Control Centers (MCC) lack monitoring and indication. Replacement of these MCCs would create operational efficiencies by providing visibility into how station service is performing. The cables require evaluation due to age of insulation and the wet conditions they have been subject to over the years. The weight due to the number of cables in the tray cause concern for potential failure (see photo below). Due to control and other additions that have occurred over time, the existing 26 year old Emergency Generator no longer meets the load critical requirements for the plant. The only components of Station Service that have been recently replaced are the Intake Motor Control Center in 2010 and the single high voltage circuit breaker serving the plant in 2015.

If no action is taken, there is a risk of individual component failure that could force load shedding under certain operational scenarios. Should a catastrophic failure occur with switchgear and/or power cables, it could result in generator unit and/or plant wide forced outages potentially lasting as long as eight months. This is due to the long manufacturing lead time for some types of specialized equipment.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Alternative #1 - Replace identified components	$4,275,000	02/2017	02/2020
Alternate #2 - New external source	$4,765,381	02/2017	02/2020

Do Nothing: doing nothing is an option. However, if components do fail, due their age, replacements are not available. Addressing such failures in an emergency/ad hoc situation would increase the cost and extend the outage time. This option does not provide any capacity for future loads.

Alternative #1 would replace the following components:

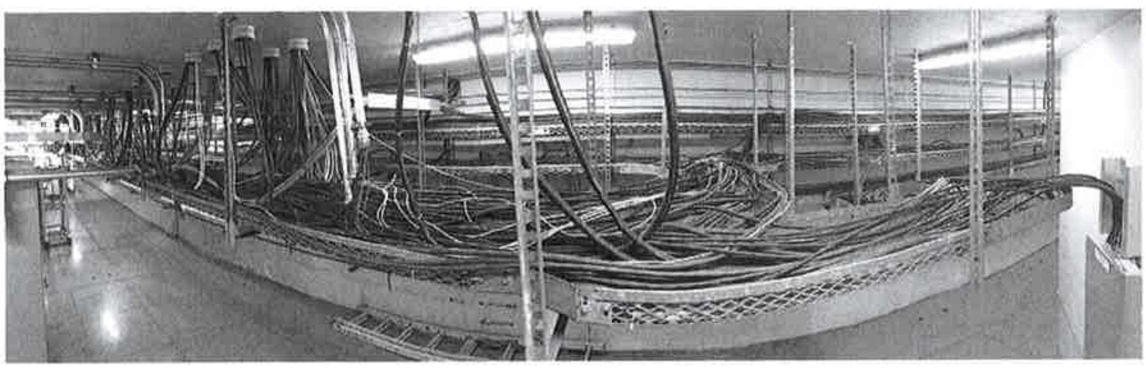
- Station Service Transformers 1 & 2
- Power Center A & B.
- Load Center 1, 2 & 4 would be replaced with Motor Control Centers with provisions for future capacity.
- Power cables
- Emergency Generator and controls to accommodate additional emergency load.
- Address arc flash rating and improve load flow analysis and coordination.
- Add metering to each Station Service Power Center and Emergency Generator.

Alternative #2: Add a second emergency generator with appropriate transformation to add capacity in the event of a failed Station Service transformer. This alternative would require the addition of another Power Center that when tied in with the others would significantly increase the complexity of the system. The additional environmental risk in the form of containment and risk of release of the Emergency Generator fuel would need to be addressed. This alternative does not address the risks associated with the overloaded cable trays and Motor Control Centers. When the costs of procuring a new generator, power center and associated cables are factored in, alternative #2 exceeds the cost of alternative #1 by $490k.

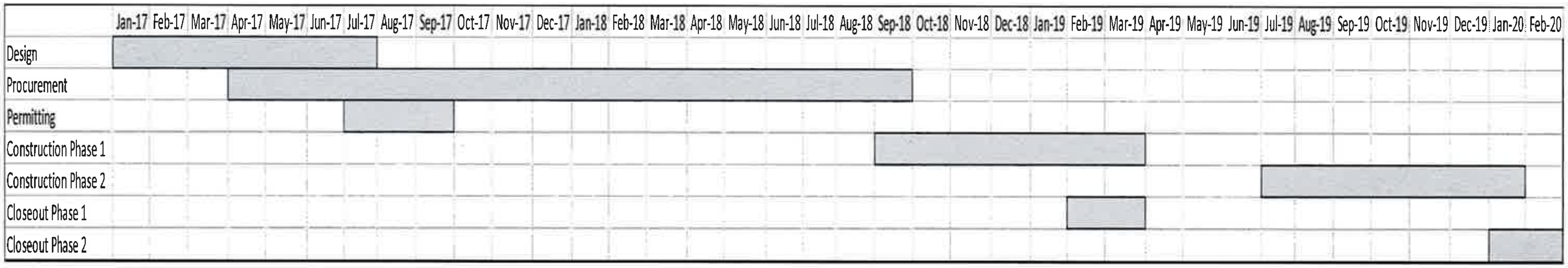
The recommended approach is alternative #1. This project aligns with both Avista's Safe and Reliable Infrastructure goal through investment to achieve optimum life-cycle performance and operational safety and Reliable Resources goal to control a portfolio of resources that responsibly meet our long term energy needs. Additionally, alternative #1 provides an avenue for prudent procurement of capital components by engaging in the competitive bid process.

This project impacts our external customers by ensuring they have predictable, affordable power. When units go offline unscheduled, we are forced to purchase power on the open market and/or produce power with our less cost effective generating facilities. These alternatives come at the risk of higher and/or unpredictable power costs per MWH for both our customers and shareholders. Finally, unscheduled outages force hydro plants to spill water which represents a FERC license violation.

Overloaded Cable Trays



Cabinet Gorge Station Service



Alternative #1 Program Cost Flows

	Year (xxxx)	Capital Cost	O&M Cost	Other Costs	Approved
Previous		$ -	$ -	$ -	$ -
Year 1	2017	$ 500,000	$ -	$ -	$ 500,000
Year 2	2018	$ 2,100,000	$ -	$ -	$ 2,100,000
Year 3	2019	$ 1,475,000	$ -	$ -	$ 1,475,000
Year 4	2020	$ 200,000	$ -	$ -	$ 200,000
Year 5		$ -	$ -	$ -	$ -
Year 6		$ -	$ -	$ -	$ -
	Total	$ 4,275,000	$ -	$ -	$ 4,275,000

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Cabinet Gorge Station Service Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 20170417

Print Name: Jacob Reidt

Title: Mgr Contract & Project Mgmt

Role: Business Case Owner

Signature: Date: 4/19/2017

Print Name: Andy Vickers

Title: Director, GPSS

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Terri Echegoyen	4/14/17	Steve Wenke	4/14/17	Initial version

Template Version: 03/07/2017

Generation DC Supplied System Update

1 GENERAL INFORMATION

Requested Spend Amount	$1,315,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Glen Farmer
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The Steering Committee for this project consists of members from the Generation Production and Substation Support Department including the Hydro Operations & Maintenance Manager, the Thermal Operations & Maintenance Manager, and the Generation Electrical Engineering Manager. Steering committee members receive project status updates when there are proposed changes to the program plan and are convened only in the event of a decision point.

The project stakeholder teams meet on a regular basis to work on the project scope and planning the project. The stakeholder teams are comprised of the representatives from Project Management, Engineering (Electrical, Controls, Mechanical & Civil), Operations, Maintenance and Compliance.

2 BUSINESS PROBLEM

This program supersedes a previous program that was identified for Battery Bank replacements only.

Traditionally, the Direct Current (DC) system, (aka Battery System) at each generation plant is used for protection and monitoring of the plant. All the protection relays, breaker control circuits and monitoring circuits are fed from this source. The source is assumed to always be on-line and able to supply the critical load for a predetermined length of time.

As technology has evolved, other standalone DC systems that were installed at different times. Typical plants now have standalone DC Systems for: general station, Uninterruptible Power Supplies (UPS), governors (electronic turbine speed controllers), communications and control systems. Each of these systems have a battery bank, battery charger, converters to supply different voltages, and distribution panels and circuits. As things have changed on the generating units or in the balance of plant systems, the DC load requirement has significantly increased and the time duration for the systems to supply this critical load has increased. Our current practice is to replace the battery banks per manufactures life cycle recommendations. This practice is not addressing the additional load added to the systems.

Some of the other issues we have had on the DC systems are the failing of battery cells due to inconsistent temperature and environmental control needed to maintain these present battery systems. The system life cycle is 20 years at its normal operating temperature of 77 degrees F. For temperatures fifteen degrees F over the normal operating temperature the life cycle is decreased by 50 percent. Component failure, utilization from multiple extended outages and manufactures quality are other problems we have experienced on these systems.

Finally there are compliance requirements from the North American Electric Reliability Corporation (NERC) for inspections, maintenance and testing of the battery banks to make sure they are in good working order and will perform when called upon. In order to perform these inspections and maintenance, and testing needs, it requires either unit or plant outages to comply with the requirements for multiple DC systems that are now present in our stations.

To address these multiple issues, a new Generation Plant DC Standard was developed by the engineering group. The new Generation Plant DC Standard System provides for layers of back up and redundancy to address current and future capacity needs as well as addressing maintenance and testing requirements. This Program will replace existing DC systems at Avista's owned and operated generation plants with a system that meets this new design standard. The Generation Plant DC Standard will be used as a guide for defining the base scope of the project.

The activity objectives is to order the plant replacements in a time line that will allow for stages of a project to happen and use our engineering and construction staffing. At each plant the DC System will be updated to meet the current Generation Plant DC System Standard and the following:

1. Comply with NERC requirements for inspection and testing.
2. Address battery room environmental conditions to optimize battery life.
3. Replace any legacy UPS systems with an invertor system.
4. Address auxiliary equipment based on life cycle.
5. Hydrogen sensing and fire alarm, eyewash station and lighting.
6. Wall separation of batteries and auxiliary equipment.
7. Install Programmable logic controller monitoring and new operating screens to provide visibility for operations and maintenance purposes.
8. Provide new distribution panels, disconnect switches, voltage conversion devices for communications equipment that operate at different voltages.
9. Establish current drawings, construction documents, I/O list, plans, schedules, manuals and as-builts.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
1. Do nothing – no action	$0		
2. Address the DC system standards as we are doing other system or unit upgrades.	$1,315,000/yr	01/2017	12/2030
3. Replace parts as they fail with the goal of making it like our standard over time.	$200,000/yr	01/2017	12/2037

4. Establish an independent DC system replacement program to bring plants to a standard as quickly as possible.	1,315,000/yr	1/20/2017	12/20/26

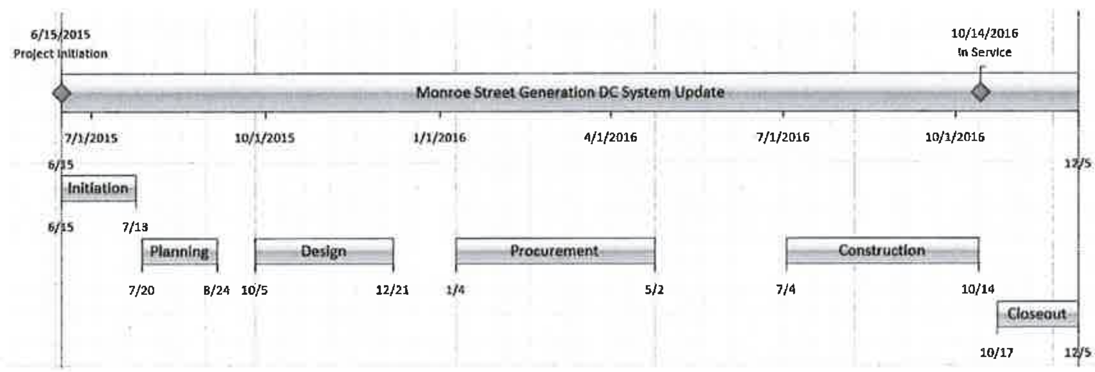
The "no action" alternative fails to address the issues associated with our current DC system. It allows for the scope of any maintenance work to balloon into a large project so if a problem arises there is not defined plan to address it. This can extend outages and leave the plant exposed for extended time frames for repairs and/or replacement parts. Upon failure we would temporarily restore the system back to working condition with the knowledge that we have to address it later. It places plant equipment at risk if a key element of the DC system were to fail, particularly the battery system. It also does not provide a means to perform required NERC testing and does not provide a means to plan for replacements costly. Also, critical AC loads served from the UPS have increased to the point where we can no longer get a UPS that is of necessary size. We would have to install more UPS systems, creating more maintenance work and increasing the NERC testing requirements. It also does not address any other issues that our design standard is intending to address. While it is a much higher life cycle cost and operationally impactful option.

Alternative 2 is to address the DC system as part of another capital project. In this case the scope of the DC system upgrade project is often a lower level effort and is subordinated to the primary project. The table below shows the current upgrade plans. While planning and scoping management can manage the concerns about making sure the DC Supplied Systems can be fully addressed, we do not have plans to work through all of the plants. This would leave the program incomplete.

Year	Plant	Comments	Cost
2014	Little Falls	DC system was built to our standard, example to follow.	$700k
2015	Nine Mile	Being addressed by Units 1&2 project	$650k
2015	GCC	Just battery bank replacement.	$250k
2016	Monroe Street	Doing design in 2015. Basis of design done. Install in 2016.	$700k
2017	Cabinet Gorge	Address existing problems with UPS system.	$700k
2018	Long Lake	Do design in conjunction with Unit Upgrades.	$700k
2019	Post Falls	Do design with plant rebuild.	$700k
2020	Kettle Falls	Steam Turbine & Gas Turbine DC System.	$700k

Alternative 3 to replace parts as they fail doesn't address any of the requirements for Standards, NERC inspection and testing, or the room itself. The parts fail at different time and we are subject to more outages. This also requires reaction to a critical system failure. Clearly replacing failed parts and components is a more costly item than performing planned work and without a planned effort, deployment of that new Generation Plant DC Standard would likely take decades. Replacing as components fail and gradually build out to our standard has the benefit of minimizing the costs of this program. However, it would be unpredictable would make labor planning impossible. This would also place the plant at a higher likelihood of forced outages and equipment damages if we wait for failure.

Alternative 4 is to construct new systems as part of a programmatic effort. This would allow for prioritized and planned series of projects to upgrade the existing station DC systems to the Generation Plant DC Standard. This will save time and expense over the life cycle of the station with the flexibility it provides to address future capacity and maintenance needs, and the ability to perform NERC required testing. It also has the benefit allowing a schedule to be established for both the engineering and the installation. Both of these resources are constrained and it would allow options of contracting or in-house consideration. A typical schedule to execute is given below. Each planned project would take approximately 16 to 18 months. Added complexity, cost, and time may be needed if extensive work is required to address the temperature and other environmental issues with the location of the new battery system.



Alternative 4 is the recommended approach. This program aligns with Avista's Safe and Reliable Infrastructure goal through investment to achieve optimum life-cycle performance and operational safety. In addition, it helps Avista meet its corporate compliance goals.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Generation DC Supplied System Update Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Glen A Farmer — Date: 4/17/17
Print Name: GLEN FARMER
Title: Generation Electrical Eng. Manager
Role: Business Case Owner

Signature: — Date: 4/19/2017
Print Name: Dr Andrew Vickers
Title: Director, GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Glen Farmer	4/7/2017	Steve Wenke	4/10/2017	Initial Version

Template Version: 03/07/2017

Solar Combustion Turbine Controls Upgrade

1 GENERAL INFORMATION

Requested Spend Amount	$ 660,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Greg Wiggins
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The plant uses a plant Budget Committee to evaluate, prioritize, and oversee project work at the station. This group consists of the Plant Manager, General Foreman, Plant Mechanic and a Plant Technician.

This project was first identified by plant technicians and plant control operators. Using past maintenance logs along with an assessment on the current status of the controls system a Project Request was submitted to the plant Budget Committee for a rebuild on the major components.

The plant Budget Committee utilizes an in-house Maintenance Project Review scoring matrix. The review process focuses around Personnel and Public Safety, Environmental Concerns, Regulatory/Insurance Mandates, Ongoing Maintenance Issues, Decreasing Future Operating Costs, Increasing Efficiency, Managing Obsolete Equipment and Assessing the Risk of Equipment Failure.

The Maintenance Project Review scoring matrix revealed risks around Ongoing Maintenance, Decreasing Future Operating Costs, Obsolete Equipment and Equipment Failure.

The project request and detailed estimate was brought forward to Corporate Finance and Planning Analyst for further analysis. The project was then presented to the Thermal Operations and Maintenance Manager for plant budget approval.

Approved projects are assigned a project Lead from the plant staff depending on discipline. Large complex projects may be assigned Engineering staff and/or a Project Manager from Generation Production and Substation Support Department to oversee. Project status and updates are discussed at the weekly plant maintenance meetings.

2 BUSINESS PROBLEM

In 2002 Kettle Falls Generating Station added a second generating unit at the facility. The new unit was a skid mounted package combustion turbine Solar Taurus 70 and (HRSG) Heat Recovery Steam Generator. The 7MW natural gas fired turbine that can be operated in simple cycle or combined cycle modes depending on energy supply needs.

When operating in simple cycle mode the unit can be started quickly and ramped up to full load to help meet load demand within 30 minutes. When operating in combined cycle mode the hot exhaust from the gas turbine is converted to steam by directing the exhaust to a heat recovery steam generator (HRSG). The HRSG creates medium pressure steam which is used to preheat water for the wood fired boiler. This increases overall plant by a 3MW increase in power output on the wood fired steam turbine generator or through an efficiency improvement by a reduction in wood consumption if the wood fired unit is already operating at full load.

Operation of the combustion turbine, HRSG and fire protection for the combustion turbine is done remotely through the Solar TTX controls system. The controls platform is legacy equipment and the control program is no longer supported by Solar. Additionally, the installed version of the Allen Bradley control network has not been supported for a number of years. The Human Machine Interface (HMI) control system used by operations functions on Windows 2000 software, which is no longer available for replacement equipment. The desktop operating computer recently failed and the plant is now operating without a spare. With this failed HMI, the HRSG cannot be operated from the local control panel at the turbine enclosure. If the one remaining HMI were to fail, the combustion turbine would only be able to be operated in the simple cycle mode as there would not be any communication with the HRSG system.

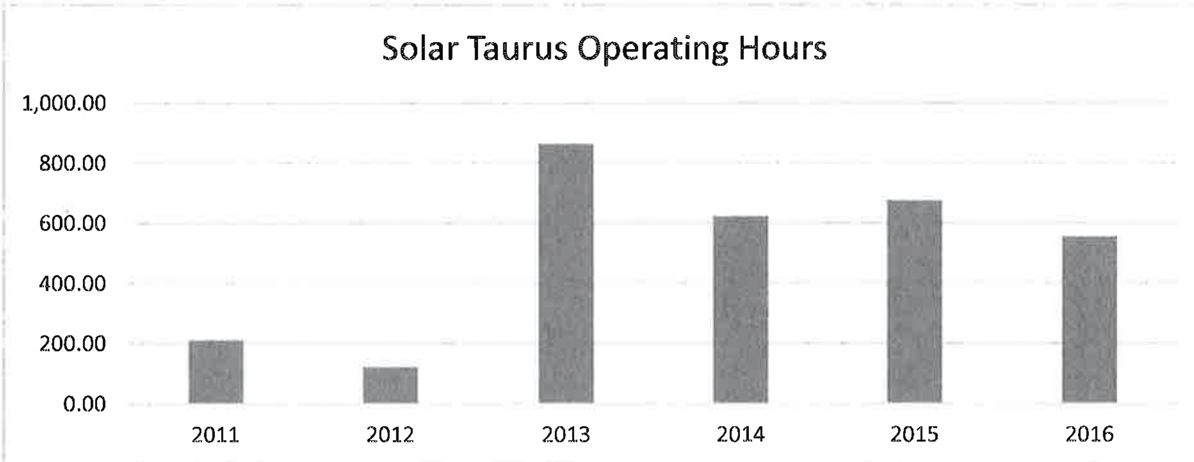
The fire protection system is no longer supported from the vendor or Solar Turbines. The unit will not operate without the fire protection system in service due to insurance requirements. The unit posted its third and fourth highest forced outage rates in the past 15 years in 2013 and 2014. The higher forced outage rate was mostly attributed to components failing within the fire protection system. The trend to the higher forced outage rate from the fire protection system is expected to continue higher.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
1. *Replace fire protection system*	*$228,000*	*04 2018*	*06 2018*
2. *Replace turbine control hardware*	*$74,000*	*04 2018*	*06 2018*
3. *Upgrade turbine controls*	*$400,000*	*04 2018*	*06 2018*
4. *Replace turbine controls and fire protection*	*$660,000*	*04 2018*	*06 2018*

The Solar Taurus 70 combustion turbine has been in commercial operation for 15 years and has run an average of 700 hours annually the past four years. The times in which the unit operates is mostly during the high load demand times in the winter and summer.

Solar Combustion Turbine Controls Upgrade



With an increase in plant operations and increasing forced outage rate, mostly attributed to control devices failing on the fire protection system, five options were discussed.

Doing nothing will eventually put the combustion turbine in an unreliable and unsafe mode.

Option 1 to replace the fire protection system hardware and controls was identified as a safety and reliability issue. The unit will not operate without the fire protection system in service due to insurance requirements. While trying to work with the fire protection system manufacture we have constantly been re-directed back to Solar for support as the fire protection manufacture no longer supports the system. Solar has stated the fire protection system upgrade would not integrate into the outdated control system without significant programing. They estimate a cost savings of nearly $60,000 if the fire protection system is upgraded with the controls system. Total estimated costs $228,000

Option 2 to replace the HMI with new hardware and newer operating system. Solar has known documented cases of our outdated operating system failing on newer than Windows 2000 systems. Solar will not guarantee the controls system will operate if we lose our only computer and try to deploy the system on a newer computer. Total estimated cost $74,000

Option 3 to replace the turbine controls software and hardware. The Solar Taurus 70 utilizes proprietary turbine controls. We have reached out to a number of third party vendors and have been told they can do controls upgrades on Solar units just not the Taurus 70. The turbine controls interface with the fire protection system and although they are separate systems they are very much integrated with each other. Solar has estimated an additional $60,000 in programing the new controls system to our fire protection system. Total estimated cost $400,000

Option 4 is to install new software and hardware in conjunction with upgrading the fire protection system with the newest turbine controls. Transfer to plant is scheduled to be June 2018 with an estimated cost of $660,000. The project would be sole sourced to Solar and would have minimal impact on internal resources.

Solar Combustion Turbine Controls Upgrade

It is recommended we pursue Option 4. Completion of the project would bring unit reliability up while maintaining safe operations. Detailed scope of work and estimates from Solar attached.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Solar Combustion Turbine Controls Upgrade Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Greg Wiggins Date: 3/29/17
Print Name: Greg Wiggins
Title: Kettle Falls Plant Manager
Role: Business Case Owner

Signature: Date: 4/19/2017
Print Name: Andy Vickers
Title: Director of GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Greg Wiggins	04/12/2017	Steve Wenke	04/12/2017	Initial version

Template Version: 03/07/2017

Kettle Falls Stator Rewind

1 GENERAL INFORMATION

Requested Spend Amount	$7,930,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The Steering Committee is comprised of the Manager of Thermal Operations & Maintenance, the Kettle Falls Plant Manager, the Manager of Contracts & Project Management, and the Manager of Electrical Engineering for GPSS.

Monthly project status updates will be distributed via email indicating the status of the scope, schedule and budget of the project.

Steering committee meetings will be coordinated if decisions need to be made, due to significant changes to the scope, schedule or budget based on unforeseen circumstances and/or risk identification.

1.2 Customers & Stakeholders:

This projects impacts internally the Thermal Operations & Maintenance teams, including the crews at Kettle Falls, Electrical Engineering and Power Supply. By providing these stakeholders with a properly maintained generator we are providing them with reliability of the system.

This project impacts our external customers by ensuring they have predictable, affordable power. When units go offline unscheduled, we are forced to purchase power on the open market and/or produce power with our less cost effective generating facilities. These alternatives come at the risk of higher and/or unpredictable power costs per MWH for both our customers and shareholders.

2 BUSINESS PROBLEM

Major Driver:

The General Electric (GE) generator at the Kettle Falls Generating Station is 32 years old (as of 2015, the time of the original funding request) and near the end of its design life. Field inspections performed by GE and by Avista using industry standard megger tests have shown a decline in the winding insulation resistance. These condition reports are attached to this document for information.

A 2014 report prepared by the Asset Management group (attached to this document) demonstrated the prudency of replacing the winding before it fails in service. Failing in service would significantly extend the outage time and the cost to repair. Scheduled work to rewind the stator is a proactive measure to ensure uninterrupted and efficient operations.

Risks:

The consequences of a stator winding failure include lost generation, loss of renewable energy credits[1], long term interruption of fuel supply, possible collateral damage to the core and hydrogen cooling system with resulting safety hazards.

Driving Metrics:

During the outage of 2007, GE completed a "Generator Inspection Report" (attached) that found through the High Voltage DC Leakage test:

- Excessive leakage in the "right phase"
  - The leakage had doubled from the year 2000 test to the year 2007 test.
  - Industry analysis has found that when the current leakage more than doubles in a particular step, it is considered a warning sign that the leakage may be approaching the point of failure. The leakage jumped from 4 micro Amps (μA) to 22 μA between these test periods. (See following graph.)

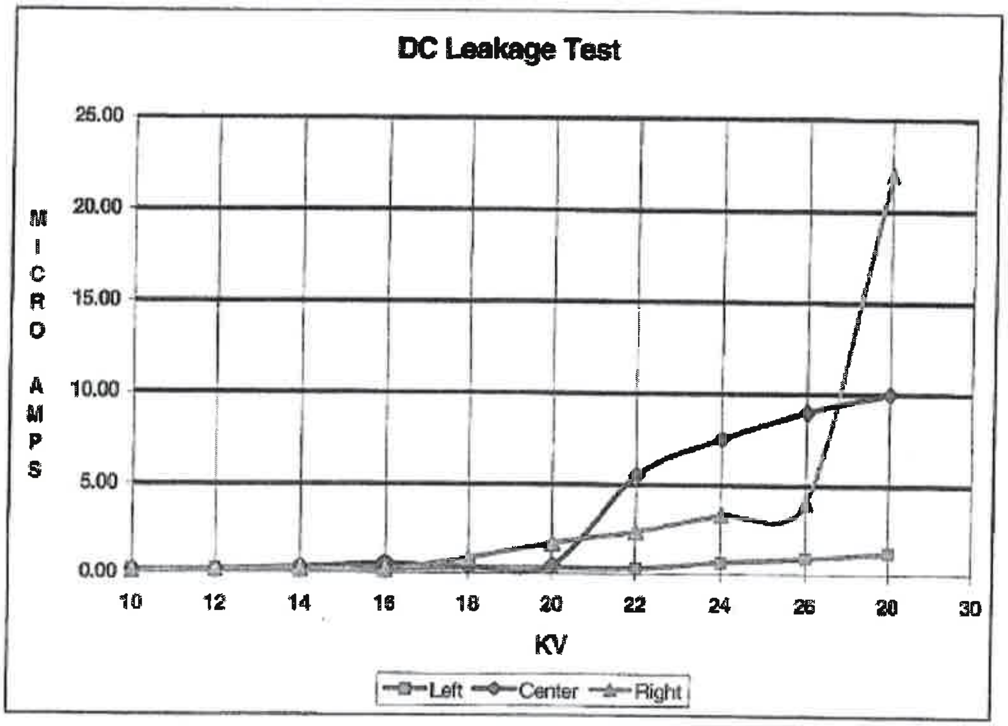
Figure 1

[1] We rely on the "green tags" produced from Kettle Falls to meet our I-937 "The Clean Energy Initiative" requirements. An unplanned outage due to a system failure could prolong the outage and put us at risk of having to incrementally procure additional Renewable Energy Credits (REC's) to meet our I-937 energy targets.

2007 GE Generator Megger Test Results

Armature Insulation DC Leakage Test

Date(m/d/y)	6/7/2007	Generator Serial No.	316X456	Prepared by	Jonathan Bellas
Customer	Avista K.Falls	Turbine Serial No.	197891		Greg Phillips
Manufacture	GE			FSR No.	94WC0587



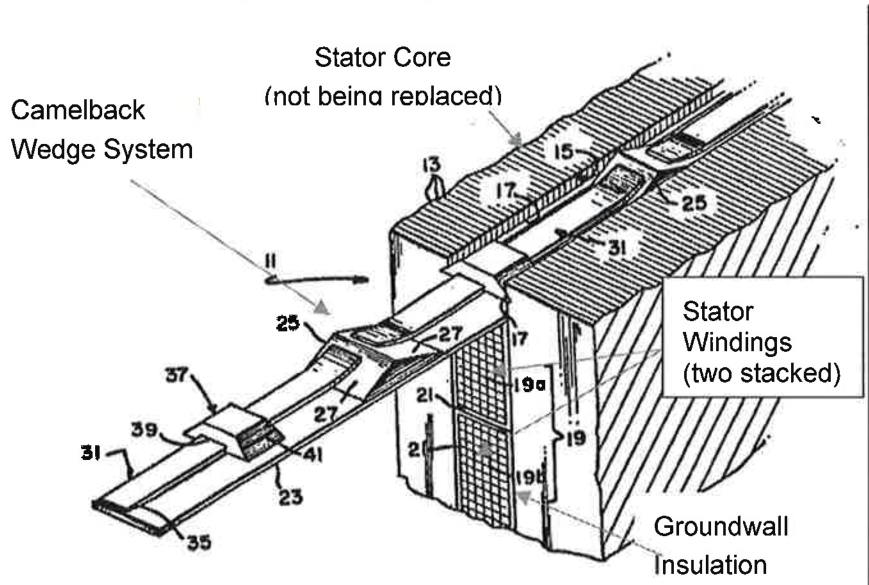
GE recommended that further DC High Potential (Hi-Pot) testing should not be conducted due to the risk of potential damage and no preparations made for the repairs necessary if the unit were to fail the test.

During the outage of 2015 an industry standard Polarization Index (PI) “Megger” test (attached) was conducted. The results shows the PI falling below 2.0 indicating problems of winding contamination, moisture ingress (leakage) and/or bulk insulation damage (conduction).

Success Measures:

Replacement of the existing stator windings and generator wedge system (sketch shown below) will improve the groundwall insulation resistance, reduce losses, and will allow the generator stator to operate at a cooler temperature. This will be validated by a successful completion of a Hi Pot test, and PI readings in excess of 6.0 for all three phases of the generator during commissioning. In addition, the operating temperatures of the unit as measured by the generator stator temperature monitors will show a lower average operating temperature.

Figure 2
Generator Coil Illustration show Winding and Camelback Wedge System
This is the general configuration for Kettle Falls.



GE has been commissioned to conduct the work and guarantees the MVA rating at a given power factor. This guarantee will be validated by a one-time test to be performed at an appropriate time after completion of the stator rewind and the unit is capable of full electrical production, but not less than 90 days after the completion of the stator rewind.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
1. Do nothing	$0		
2. Stator Rewind (recommended)	$7.93M	05 2015	06 2017
3. Generator Upgrade	Unidentified	05 2015	06 2017

Impacts:

The impacts are improved reliance on the system for the Kettle Falls operators and the Power Supply department. No additional O&M costs will be incurred as a result of this project nor will any O&M costs be reduced and/or eliminated.

Alternatives:

Option 1 to "do nothing" would increase our risk of an unplanned and potentially catastrophic outage. As described, test results conducted over time show a continuing decline in the winding condition and provides reasonable doubt about the ability of the present stator winding to continue to operate reliably for any duration of time.

Option 2 to perform a Stator Rewind has been demonstrated by a study from the Asset Management group to be a preferred option. This alternative minimizes outage time and removes the concerns of the failing stator insulation system and the potential for a catastrophic failure of the generator.

The Option 3 alternative to "upgrade" the generator to produce additional MWH output was determined to be unfeasible, based on a "Feasibility Analysis" (attached) conducted by contractor H2E in May 2015.

Risk Mitigation:

This project significantly reduces our risk of an unplanned, and possible catastrophic, outage by replacing the existing stator winding.

The risk of an unplanned outage increases the cost of the outage and the length of the outage due to the long lead time for stator bar order, construction and delivery. By proactively scheduling the rewind of the stator we are reducing the risk of an unplanned and potentially catastrophic outage. Firm costs and schedules can be achieved working with suppliers and installers to minimize the costs and time within acceptable windows.

Timeline:

- Design – 2015
- Request For Proposal (RFP), Contract Awarded, Planning – 2016
- Construction, In Service – 2017

Alignment with Strategic Initiatives:

Safe and reliable infrastructure. This project will improve the ability to sustain safe systems that deliver energy effectively and efficiently at all times. In addition, the Kettle Falls Generating Station, as a biomass fueled generating station, is one of the responsible resources in Avista's diverse generating portfolio for our customers. This project will allow for the safe and continued operation of this key resource.

Budget:

The rough +/- 50% estimate for the project began at $7.93M. The current estimate with +/- 10% accuracy is $5.43M.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Kettle Falls Stator Rewind Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	20170417
Print Name:	Jacob Reidt		
Title:	Mgr. Contracts & Project Management		
Role:	Business Case Owner		

Signature:		Date:	4/19/2017
Print Name:	Andy Vickers		
Title:	Director GPSS		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Tara Moses	3/28/2017	Steve Wenke	4/6/2017	Initial version

Template Version: 02/24/2017

Little Falls Spillway Flashboard Replacement

1 GENERAL INFORMATION

Requested Spend Amount	$20,000,000 - +/- 30%
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

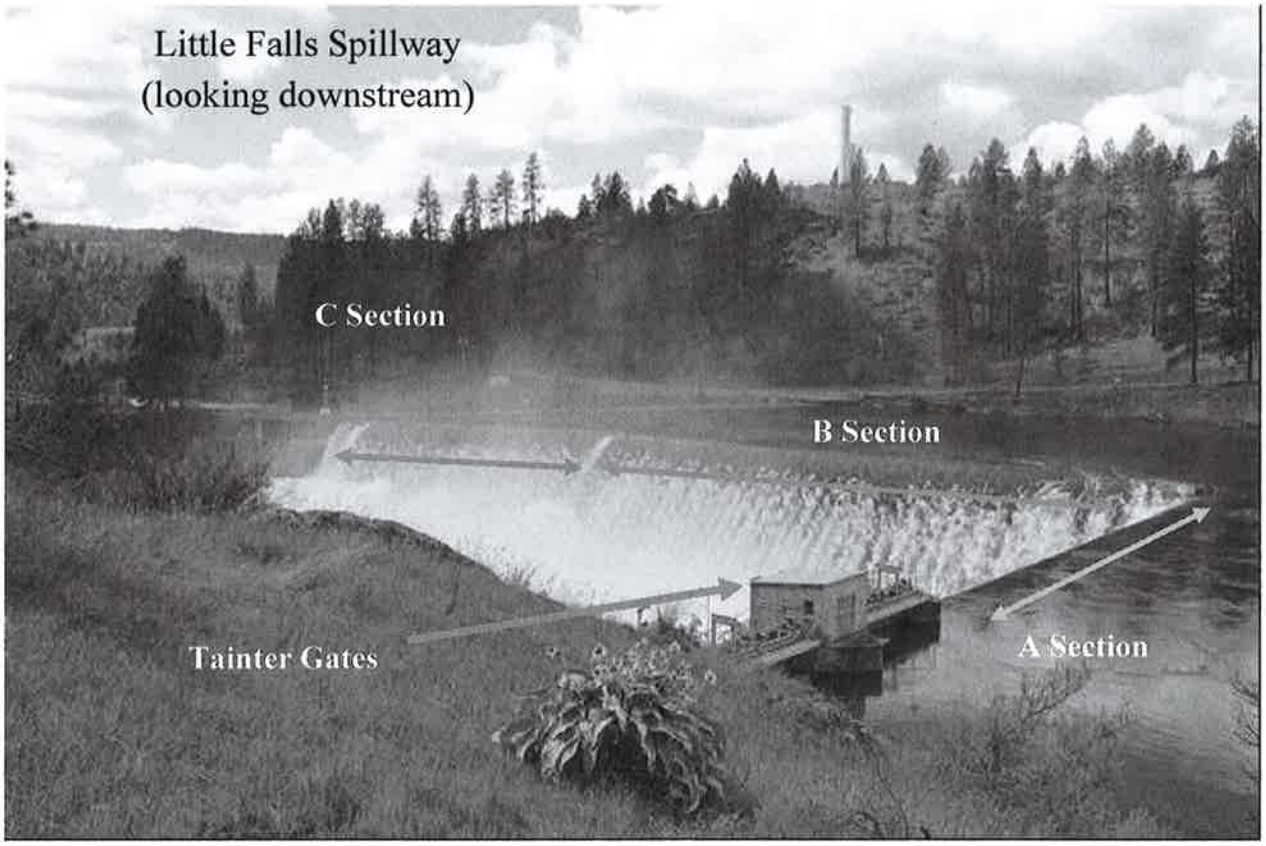
This program is comprised of two layers of Steering Committee Oversight. One layer of oversight is at the program level and the other layer is at the project level.

The Program Steering Committee is responsible for vetting and approving the objective, scope and priority of the program. The deliverables for the program are then reviewed with the Program Steering Committee on a semi-annual basis. Any significant changes to the program's scope, budget or schedule will be approved by the Program Steering Committee.

Each member of the steering committee represents a major stakeholder in the project. The Project Steering Committee will approve and changes to the schedule, scope and budget of the individual project. They also are responsible for approving the necessary personnel for the completion of the project.

2 BUSINESS PROBLEM

The spillway at Little Falls was originally constructed as a free flow spillway with two tainter gates (a specific type of spillgate) installed on the left embankment to provide some reservoir control for the plant. To get more output from the plant, flashboards were added in the 1940's that increased the head of the plant, producing more energy. These flashboards are in three long sections. The 185 foot long section A, the 262 foot long Section B, and the 150 foot long Section C. (The two tainter gates make up the balance of the controlled spillway.



When flows exceed the capacity of the available generating units and the two tainter gates, one or more sections of the flashboard must be "pulled" or "tripped" or removed to prevent flooding upstream. Section A and Section C are tripped by using a long wire cable that is strung around the flashboards. The cable is routed though makeshift pulleys to a point where a truck with a front-end winch can be attached to the cable on the shore of the reservoir. As the winch pulls the cable, the retracting cable pulls the flashboards away from their bracing. The force of the height of the water helps the cable "rip" the flashboards from the bracing releasing the water. The Flashboards themselves are flooded downstream. They are not recovered.

If the Section B portion of the flashboards need to be removed, that operation requires placing crews in barges out on the reservoir and manually cut out or knock out the support bracing in order to then push over the flashboards.

Both the cable trip system and the manual method have significant safety implications to the personnel who are performing the work. This is the primary issue to be addressed by this project.

With the cable system, there is significant tension required on the cable and the winch to pull these long lengths of flashboards. Under these tensions, should the cable snap, it could re-coil and cause damage to equipment. More significantly, this recoil would be uncontrolled and could possibly strike personnel.

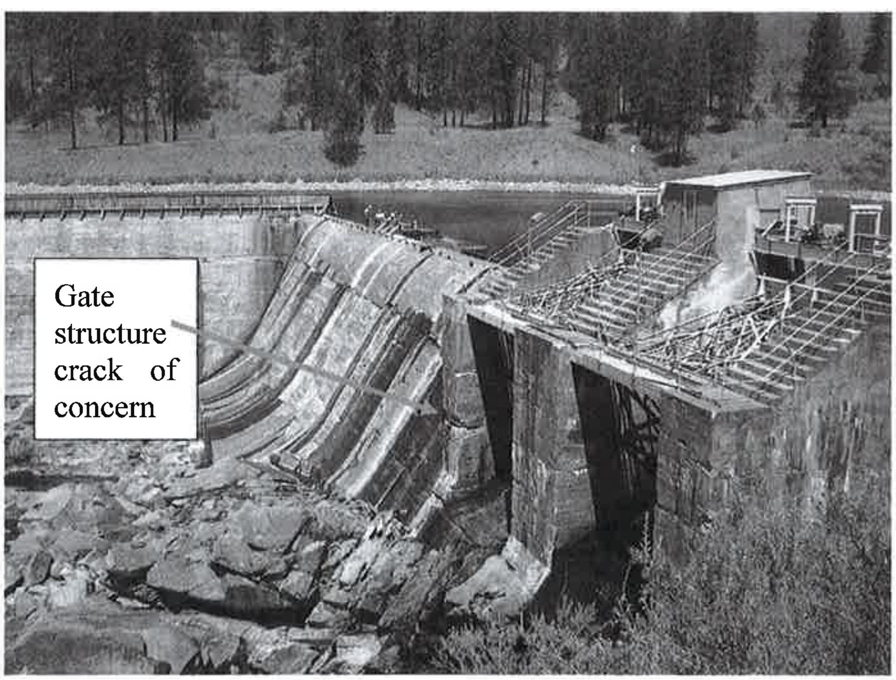
More critically is the manual method needed to remove the flashboards in Section B. This requires extensive work by the Hydro Operations Engineers to anticipate if the flashboards will need to be removed. They need to make this assessment in enough time to allow the reservoir to be drawn down and held at a level below the spillway crest to allow crews to access the center section (Section B) and remove the flashboards. Should unanticipated flows come faster than expected, or if a generating unit trips off, the reservoir level can rise relatively quickly. This places crews at risk of being taken over the face of the dam if they are unable to egress quickly enough.

Failure to remove all of the flashboards can cause flooding upstream which is unacceptable. Removing the flashboards when it isn't necessary cost our customers by not generating as much energy as possible. While this has been going on for many years, it is still a stressful time that can be eliminated if the flashboards are replaced.

A secondary issue is the annual cost of having to purchase and replace the flashboards that are tripped and washed downstream. In addition, both tripping the flashboards and then re-installing them after the high flows have receded requires crews to be dispatched. To re-install the flashboards, it typically takes 10 to 14 days.

Last, because the flashboards cannot be restored until after flows move below plant capacity to allow crews to safely, there is a loss of head that reduces the energy from the plant. Studies have been done to show that the energy loss alone does not cost justify the replacement of the flashboards with a system that will allow control, but there is an increase in energy production that can be achieved.

Finally, any option considered will include repairs of the existing tainter gate structure. The right side pier has a structural crack that runs through the entire element. The gates have some minor structural issues that need to be addressed, the hoist drive and chain systems have had some issues in the past. Other maintenance items will be evaluated and addressed, even if "Do Nothing" is selected.



3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
1. Do Nothing	$0	2017 and going forward		
2. Continue current operation	$0	annual		$155,000 in O&M Expense
3. Install a "rubber dam" (or similar) along the entire length of the free flow crest	$18M	2019	2022	
4. Install flap gates (or similar) along the entire length of the free flow crest	$22M	2019	2022	
5. Install some combination of controlled spillgate (rubber dam or flap gate) along with a type of engineered release system	$15M	2019	2022	

The estimates in the above table for capital costs should be construed to be +/- 30% for each of the options. The O&M Risk Mitigation is calculated in the attached spreadsheets prepared by Power Supply.

The first alternative that could be considered is to Do Nothing. This option would mean that all the flashboards would be permanently removed and not replaced with any type of alternative. This alternative would address the safety concerns as crews would not long have to restore flashboards. This would put the project back to an operating head at the concrete spillway crest, about 8 feet lower than current levels. This would result in a (8feet / 60 feet total head =) 13% loss of energy for the project each year. This energy would have to be replaced by additional power supply purchases.

Alternative 2 is to continue the current system of installing and tripping flashboards each year. This does not address the safety issues that are the primary drivers of this project. Additionally, the other issues of cost of installing flashboards each year and the loss of energy production due to the fluctuating head.

Alternative 3 would install a "rubber dam" along the length of the crest. This could be an Obermeyer type system similar to the one installed at Nine Mile or an inflatable bladder system, such as those made by Mecan Hydro, that is also common in the industry. These would function similar to flashboards in that large section of water would be released in one operation so they could provide crude regulation. (Fine reservoir control would continue to be provided by the two tainter gates.)

Alternative 4 would replace the entire length of the spillway with a series of metal flap gates. These gates would hinge on the crest and utilize a hydraulic system to raise. These would be sized such that they could be operated over a full range of flows and head conditions. These types of gates are used in many applications and have been installed in several locations where flashboards were used previously. While expensive, these provide the widest range of operational flexibility and maximize the ability to control the level of the reservoir.

Alternative 5 is some combination of a rubber dam or a flap gate system along with an engineered type of flashboard system such as one made by Hydro Plus. These engineered flashboards are designed to overflow to a pre-determined level. At some point, they will tip over, similar to wooden flashboards. The difference is they simply tip over and do not wash downstream like the flashboards. They can be quickly reset, but the reservoir needs to be lowered to allow crews on the spillway. The advantage of a combination system is that it would be less expensive and would be designed such that the engineer flashboard system would only have to be reset on flows once every 20 years or so, but design. (Actual stream flows would dictate the occurrence.)

As of the presentation of this Business Case Justification Narrative, the recommended alternative has yet to be determined. As these alternatives evolve, considerations such as impacts to the spillway, frequency of operation, construction considerations and of course benefit/costs will need to be considered. This is to establish a planning process to determine a final proposed solution.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Little Falls Spillway Flashboard Replacement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Jacob Reidt Date: 20170417
Print Name: Jacob Reidt
Title: Mgr Contracts & PM
Role: Business Case Owner

Signature: Andy Vickers Date: 4/19/2017
Print Name: Andy Vickers
Title: Director, GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Steve Wenke	04/14/2017	Jacob Reidt	04/17/2017	Initial version

Template Version: 02/24/2017

1 GENERAL INFORMATION

Requested Spend Amount	$56,100,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

This program is comprised of two layers of Steering Committee Oversight. One layer of oversight is at the program level and the other layer is at the project level.

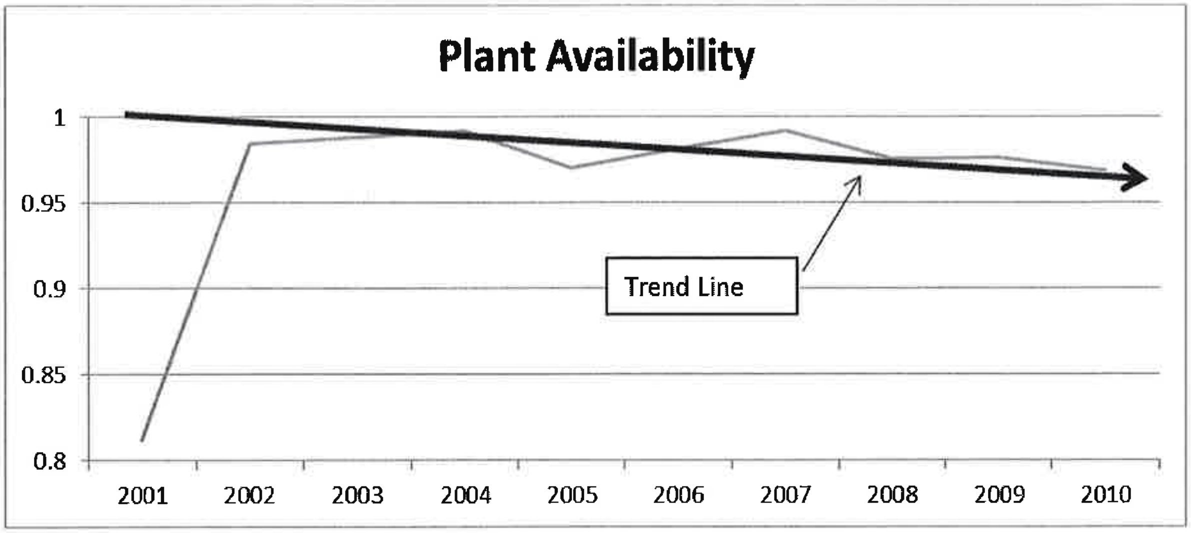
The Program Steering Committee is responsible for vetting and approving the objective, scope and priority of the program. The deliverables for the program are then reviewed with the Program Steering Committee on a semi-annual basis. Any significant changes to the program's scope, budget or schedule will be approved by the Program Steering Committee. The Program Steering Committee is composed of the Director of GPSS and the Director of Power Supply. This committee meets semi-annually or as major events create a change order request.

The Project Steering Committee oversees the deliverables of the individual projects. Each member of the steering committee represents a major stakeholder in the project. The members are dependent on the respective project but will include representatives from hydro operations, central shops and engineering. The Project Steering Committee will approve and changes to the schedule, scope and budget of the individual project. They also are responsible for approving the necessary personnel for the completion of the project. This group is engaged on a quarterly basis.

2 BUSINESS PROBLEM

The existing Little Falls equipment ranges in age from 60 to more than 100 years old. Little Falls experienced an increase in forced outages over the past six years, increasing from about 20 hours in 2004 to several hundred hours in the past several years, due to equipment failures on a number of different pieces of equipment.

The major drivers for the Little Falls Plant Upgrade are available and reliability. See the graph below that illustrates the trend line for availability at Little Falls.



Once the business case is complete, a study of forced outages at the plant over a 5 year period could be taken and measured against the pre-construction outage numbers to determine if plant availability has increased and the business case objective met.

3 PROPOSAL AND RECOMMENDED SOLUTION

Below is a breakdown of the capital construction cost associated with each alternative and any ongoing maintenance costs associated with each alternative.

	Capital Cost	O&M Cost
Status Quo	$0	$150,000/yr +
Alternative 1	$5,000,000	$20,000/yr +
Alternative 2	$83,000,000	$0
Proposed Alternative	$56,100,000	$0

Summary of alternatives:

Status Quo: Forced outages and emergency repairs would continue to increase, reducing the reliability of the plant. Each time a generator goes down for an emergency repair, Avista is forced to replace this energy from the open market which leads to higher energy costs.

It is expected that the O&M costs would continue to climb as more failures occurred. This may also require personnel to be placed back in the plant to man the plant 24/7 in order to respond to failures. Again, increasing expenses for the project with no benefit in performance.

Alternative 1: Replace Switchgear and Exciter: This would replace the two items that are currently responsible for the majority of the forced outages, and then continue to use the remaining equipment.

This alternative is a temporary fix. One of the generators has a splice and is expected to fail in the next few years. If this generator fails before a new generator is ordered, this generator will be out of service for 2 years. The control system is a vintage system and is on the verge of a total failure and spare parts are not available (a few minor system failures occurred in the past 2 years). If a total system failure is encountered, it is expected the plant to be down for a year as the control system is designed, procured and installed.

Alternative 2: Replace all generating units with larger, vertical units capable of additional output. Avista's Power Supply group evaluated the present value of larger, vertical units at Little Falls. The increase in present value from larger units was $20M over a 30 year analysis. The capital construction cost increase from in-kind replacement to vertical units was $27M.

This present value calculation of benefit did not include risk. Installing new vertical units would require modification of the powerhouse foundation and presents serious construction risk. Due to the high construction costs, high risk, and low payoff NPV, this alternative was abandoned.

Alternative 3 and Proposed Alternative: Replace nearly all of the older and less reliable equipment with new equipment. This includes replacing two of the turbines, all four generators, all generator breakers, three of the four governors, all of the AVR's, removing all four generator exciters, replacing the unit controls, replacing the unit protection system, and replacing and modernizing the station service. All major equipment would be procured through a competitive bid process to help keep construction costs low. Equipment would also be purchased for all four units at once to help keep costs down.

Additional Justification for Proposed Alternative:

Because of the age and condition of all of the equipment at the plant, all of the equipment has been qualified as obsolete in accordance with the obsolescence criteria tool. The Asset Management tool has been applied to Little Falls and also supports this project. The Asset Management studies that have been done to date are still subject to further refinements, but the general conclusions support this project. There are many items in this 100 year old facility which do not meet modern design standards, codes, and expectations. This project will bring Little Falls to a place where it can be relied on for another 50 to 100 years. Finally, this project will need to be worked in coordination with our Indian Relations group as the Little Falls project is part of a settlement agreement with the Spokane Tribe.

Milestone Schedule:

January 2010	Program Begins
March 2012	Exciter & Generator Breaker Replacement Complete
January 2014	Warehouse Construction Complete
January 2014	Bridge Crane Overhaul Complete

Little Falls Plant Upgrade

February 2015	Station Service Replacement Complete
February 2016	Unit 3 Modernization Complete
April 2017	Unit 1 Modernization Complete
October 2017	Backup Generator Install Complete
May 2018	Unit 2 Modernization Complete
May 2019	Unit 4 Modernization Complete
October 2019	Headgate Replacement Complete

Yearly Transfer to Plant:

2013	$3,100,000
2014	$2,000,000
2015	$4,000,000
2016	$16,300,000
2017	$10,400,000
2018	$9,000,000
2019	$13,000,000
Total	$57,800,000

Strategic Alignment:

The Little Falls Plant Upgrade aligns with the Safe and Reliable Infrastructure company strategy. The program will address safety and reliability issues while looking for innovative, economical ways to deliver the projects.

Customers and Stakeholders:

Mike Magruder	Manager, Hydro Operations and Maintenance
Alexis Alexander	Manager, Spokane River Hydro Operations
Kevin Powell	Chief Operator, Long Lake and Little Falls HED

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Little Falls Plant Upgrade Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ______________________ Date: 20170417

Print Name: Jacob Reidt

Title: Mgr Contract & Project Mgmt

Role: Business Case Owner

Signature: ______________________ Date: 4/19/2017

Print Name: Andy Vickers

Title: Dir Gen Prod Sub Support

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Brian Vandenburg	02/14/2017	Steve Wenke	04/10/2017	Initial Creation

Template Version: 02/24/2017

Long Lake Replace Plant Emergency Generator

1 GENERAL INFORMATION

Requested Spend Amount	$725,000 - +/- 30%
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Glen Farmer
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

This project is to be collectively managed by the Project Steering Committee. The Project Steering Committee is responsible for vetting and approving the objective, scope and priority of the program. The deliverables for the program are then reviewed with the Program Steering Committee at least on quarterly basis. Any significant changes to the program's scope, budget or schedule will be approved by the Program Steering Committee.

The Project Steering Committee oversees the deliverables of the individual project. The Key Steering Committee members are the Manager of Spokane River Hydro Operations, the Chief Operator of Long Lake and Little Falls HED, the Manager of Electrical Engineering for GPSS, the Manager of Maintenance and Construction, and a Hydro Operations Engineer.

Each member of the steering committee represents a major stakeholder in the project. The Project Steering Committee will approve any changes to the schedule, scope and budget of the project. They also are responsible for approving the necessary personnel for the completion of the project.

The Steering Committee will provide an update on a quarterly basis to the Manager of Hydro Operations and Maintenance. This will primarily be a budget, schedule, and scope discussion.

2 BUSINESS PROBLEM

The Long Lake Plant Emergency Generator serves as a back-up power source for critical unit systems in case the station service is lost. It was installed in the mid 80's. The system is designed to provide necessary power to essential systems that are needed to provide power to systems to protect machinery and personnel in the event of a complete loss of station service power. A partial list includes power for governor oil pumps to maintain control of the turbines, sump pumps to prevent the plant from flooding, power to the battery chargers to keep the critical DC system available, and some egress lighting for personnel to safely navigate the area.

The system is made up of three primary systems. The Emergency Generator, controls and power leads are one component. The Transfer Switch that connects either the normal station service or the emergency generator to the critical Load

Center is the second. The third component of the system is the Critical Load Center which provides the distribution network to the critical loads.

The unit is tested on a monthly basis. To perform this test, operators will manually start the emergency generator and then manually tie the emergency generator to the station service system. They then synchronize the emergency generator to the station service system. This then allows the operators to load the emergency generator and exercise its control systems.

Recently, problem have come up in the reliability of the Transfer Switch to allow unit to synchronize to the station service. These problems lead to uncertainty about the ability for the transfer switch to cut over to the critical bus in the event of an actual loss of normal station service supply. The Transfer Switch has no spare parts and the equipment is no longer manufactured making repair or improved reliability impossible.

In addition, the emergency generator controls are now well over 30 years old and parts are no longer available. While the controls are functional, they were designed for a multi-staff operating plan do not provide the visibility and capability needed for the single operator operation that we run today. The technology needs to be upgraded.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
1. Do Nothing	$0	2017 and going forward		
2. Continue current operation	$0	annual		
3. Replace the transfer switch	$300,000	2020	2022	
4. Update the system by replacing the emergency generator controls, transfer switch, and Critical Load bus systems; overhaul the current EG	$700,000	2020	2022	
5. Update the system by replacing the emergency generator controls, transfer switch, and Critical Load bus systems and add capacity to the system by replacing the 30+ year old emergency generator	$$725,000	2020	2022	

The estimates in the above table for capital costs should be construed to be +/- 30% for each of the options.

The first alternative that could be considered is to Do Nothing. This option would mean that the present emergency power system be removed from service and not replaced with any type of in-kind type of service. This would place the equipment at risk due to loss of station service and could create personnel hazards if the failure were at night and a person was away from the control room. Because of the equipment and personnel risk, this option was not considered viable.

Alternative 2 is to continue the current using the present system and hope that repairs to the transfer switch may be accomplished to improve the reliability of the system. If repairs are implemented, they would need to use parts custom fabricated to retrofit the system. While this may address the immediate need, the engine controls and transfer switch controls still do not provide the visibility needed to operate and monitor the plant. This option does not address the problems with the transfer switch reliability nor does it meet the objective of providing the controls necessary to support our present operation. Because of the suspect reliability, an option to rent a skid mounted unit with a transfer switch could be considered. This would be a temporary arrangement but would cover some time until a more permanent solution could be implemented.

Alternative 3 would partially address the objectives by replacing the existing transfer switch with a new system and resolve the reliability issues. However, the existing generator controls and other systems would still use the existing controls and be subject to the limitations of those.

Alternative 4 would replace the entire plant emergency generator and supply system with new equipment. This would address the maintenance and reliability issues of the transfer switch and update the overall control systems to allow for the needed visibility and automation to control and monitor the emergency power system with the present operating plan. In addition, this work will evaluate the present emergency generator engine to determine if it needs to be overhauled. While the engine does not have a lot of operating hours, it is more than 30 years old and it may warrant an overhaul for continued reliable service.

Alternative 5 is the same as Alternative 4 except in this alternative we would procure a new emergency generator unit and replace the present unit. This would include new controls as well. The benefit of this option is it would provide an entirely new emergency power system and would be able to adjusted to account from possible incremental capacity additions that have occurred as the plant control system have evolved.

As of the presentation of this Business Case Justification Narrative, the recommended alternative has yet to be determined. As these alternatives evolve, considerations such as additional capacity needs, plant staffing plans, remote capability, and other critical system needs will be considered. This business case is to establish a planning process to determine a final proposed solution.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Long Lake Replace Plant Emergency Generator Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Glen S Farmer Date: 4/18/17
Print Name: Glen Farmer
Title: Generation Electrical Eng. Manager
Role: Business Case Owner

Signature: [signature] Date: 4/19/2017
Print Name: Andy Vickers
Title:
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Steve Wenke	04/17/2017	Jacob Reidt	04/17/2017	Initial version

Template Version: 02/24/2017

Long Lake Plant Upgrade

1 GENERAL INFORMATION

Requested Spend Amount	$46,000,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

This program is comprised of two layers of Steering Committee Oversight. One layer of oversight is at the program level and the other layer is at the project level.

The Program Steering Committee is responsible for vetting and approving the objective, scope and priority of the program. The deliverables for the program are then reviewed with the Program Steering Committee on a semi-annual basis. Any significant changes to the program's scope, budget or schedule will be approved by the Program Steering Committee. The Program Steering Committee is composed of the Director of GPSS, Director of Environmental Affairs, and the Director of Power Supply. This committee meets semi-annually or as major events create a change order request.

The Project Steering Committee oversees the deliverables of the individual projects. Each member of the steering committee represents a major stakeholder in the project. The members are dependent on the respective project but will include representatives from hydro operations, central shops and engineering. The Project Steering Committee will approve and changes to the schedule, scope and budget of the individual project. They also are responsible for approving the necessary personnel for the completion of the project. This group is engaged on a quarterly basis.

2 BUSINESS PROBLEM

The existing Long Lake equipment ranges in age from 20 to more than 100 years old. We have experienced an increase in forced outages at Long Lake over the past six years, almost zero in 2011 and increasing every year since then. This is caused by equipment failures on a number of different pieces of equipment. Specifically, the turbines are thrusting too much (a sign of significant wear), including a failure in 2015. The 1990 vintage control system is failing and only secondary markets can support this equipment.

The original generators consist of a stator frame, stator core, stator winding, and rotor field poles. They were originally rated at 12 MW's. In the late 1940's, the height of the dam was raised 16 feet which resulted in more operating head for the generating units. A forced air cooling system for the generators was added to the plant at that time to accommodate the increase in output from 12 to 17 MW's due to the increased head. In the 1960's, the stator windings on all of the units were replaced and the rating of the generators, along with the forced air system allowed for the units to operate at the higher 17 MW output.

In the 1990's, the original turbine runners were replaced and upgraded. The improvement in turbine runner efficiency resulted in still another increase in unit output. Since the mid-1990's, the generators have been operating with a maximum output of 22 to 24 MW's. The generators are currently operated at their maximum temperature which stresses the life cycle of the already 50+-year-old winding.

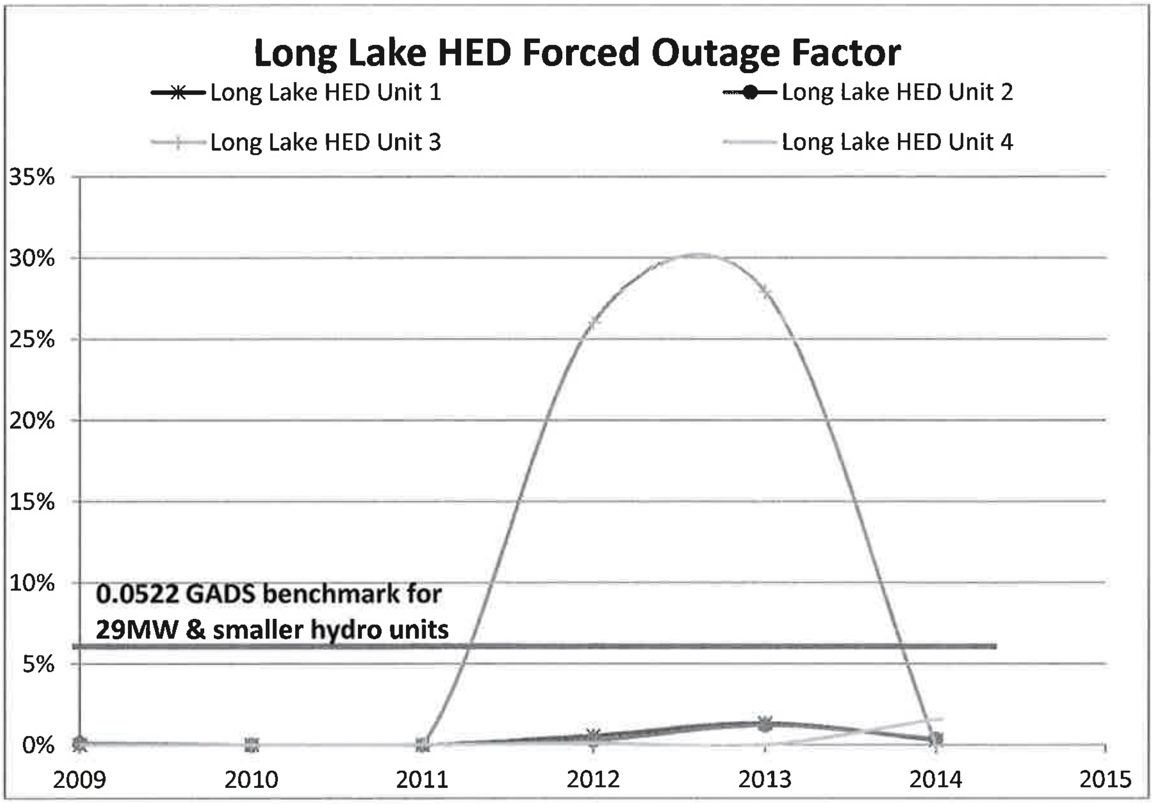
Inspections of other components of the generator show the stator core is "wavy". The core lamination steel should be in straight. The "wave" pattern is a strong indication of higher than expected losses are occurring in the generator. Finally, maintenance reports have identified that the field poles on the rotor have shifted from their designed position very slightly over the years. While there can be several causes of this movement, it is speculated that it is due to the high operating temperatures of the generator. This highlights the first driver for the program, reliability.

With the increase in generator output, the output of the generator step up transformer (GSU) has also increased to its rating. These GSU's are now running at the high 65C temperature which is a concern. As these GSU's are more than 30 years old and operating at the high end of their design temperature, these are now approaching their end of useful life and need to be replaced proactively rather than wait for a failure.

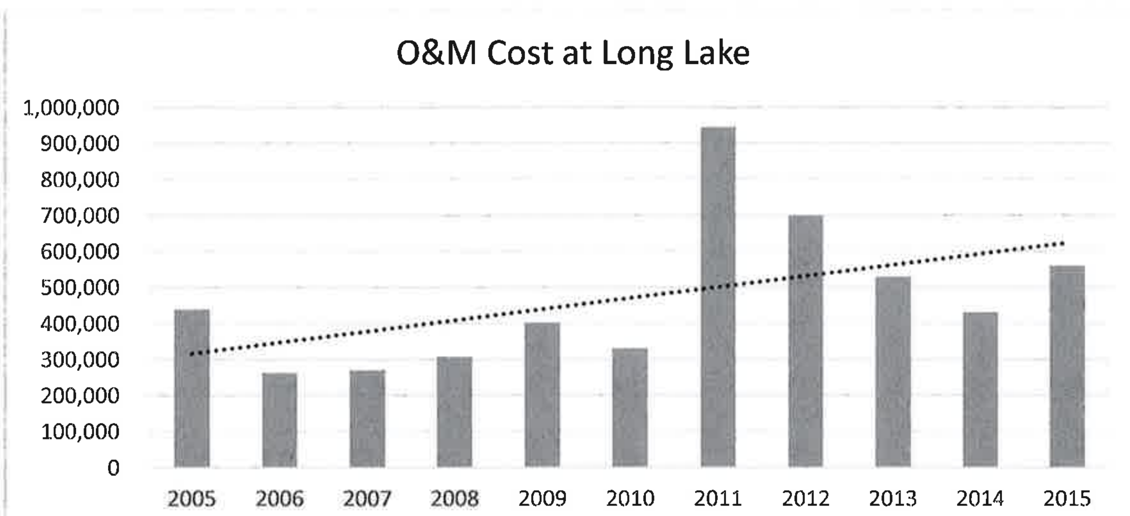
The other major driver for the program is safety. The switching procedure for moving station service from one generator to the other resulted in a lost time accident and a near miss in the past 5 years. In addition, the station service disconnects represent the greatest arc-flash potential in the company. This area is roped off and substantial safety equipment is required to operate the disconnects. This project will reconfigure this system to eliminate requiring personnel to perform this operation and avoid the arc-flash potential area.

Below is a graph of Forced Outage Factor for Long Lake HED from Avista's Asset Management Plan.

Long Lake Plant Upgrade



The below graph shows the O&M cost at Long Lake for the past 11 years. The trendline is increasing due to increasing repairs to aging equipment.



The above graph shows the O&M cost at Long Lake for the past 11 years. The trendline is increasing due to increasing repairs to aging equipment.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Requested Start	Requested Complete
Do nothing	$0	N/A	
Recommended: Replace Units In-Kind	$46M	05/2018	06/2024
Alternative 1: Install four new 60MW vertical units	$173M	05/2018	04/2023
Alternative 2: Construct one unit powerhouse	$144M	05/2018	07/2021
Alternative 3: Construct two unit powerhouse	$276M	05/2018	11/2021
Alternative 4: Replace Units In-Kind	$46M	05/2018	06/2024

Do Nothing: Continue to run plant and repair as necessary

The Long Lake powerhouse would continue to operate as it has for the past 10 years. O&M costs would continue to rise. In an additional 10 years, if the trend continues, average O&M costs will rise from $285k in 2005 to $590 in 2014 and projected to be $900k in 2024. Due to the condition of the generators, it is likely that one of the generators or another piece of major equipment will fail and permanently disable equipment, increasing forced outage numbers.

Alternative 1: Install four new 30MW vertical units

This alternative would be to replace the four existing units in the powerhouse with four new 30 MW Kaplin units. Significant civil, electrical and mechanical work would be required, in addition to powerhouse access.

The increased yearly generation would be 114,000MWh. Using $30/MWh (extremely conservative number) the rough yearly benefit to Avista is $3.4M. The payoff period is greater than 30 years and therefore this alternative was abandoned.

Alternative 2: Construct one unit powerhouse

Instead of upgrading the current powerhouse, this alternative is to construct a new powerhouse with a single, 68MW next to the existing powerhouse, using the saddle dam (also referred to as the "arch dam") as an intake. This alternative would only use the old powerhouse during high flows, when flows exceeded the new unit's capacity. Additional funds would be required to upgrade, even at a minimum level, to address some of the failing components.

The increased yearly generation would be 170,000MWh. Again, using $30/MWh the rough yearly benefit to Avista is $5.1M. The payoff for this is 30 years. Again, since this cost does not include the additional work required in the plant and the cost of the risk associated with modifying the saddle dam, this alternative was abandoned.

Alternative 3: Construct two unit powerhouse

Another option to build a new powerhouse is to construct a new powerhouse with two, 76MW units next to the existing powerhouse. This alternative would also use the saddle dam as an intake. This alternative would only use the old powerhouse during extreme high flows, minimizing the need to perform any upgrades to the old plant.

The increased yearly generation would be 258,000MWh. Using $30MWh, the rough yearly benefit to Avista is $7.7M. The payoff would be greater than 30 years and therefore the alternative was abandoned.

Alternative 4 and Recommended Alternative: Replace units in-kind

This alternative would replace the existing major unit equipment (generator, field poles, governors, exciters, generator breakers) with new equipment.

Over the past 11 years, the average O&M spend at Long Lake was $470k, with the low being $262k and the high year being $944k. In addition, the O&M cost is trending upward. After the upgrade, the expected O&M cost is $200k/year, an average reduction of $270k/year.

Milestone Schedule:

May 2017	Project Kickoff
Sept 2018	Vertical Elevator Replacement Complete
Dec 2018	Bridge Crane Replacement Complete
Nov 2018	Sewer System Overhaul
Oct 2019	Access Road Overhaul
Dec 2019	Facility Upgrades
Oct 2019	Station Service Replacement
Apr 2021	Unit 1 Overhaul
Oct 2020	Air System Overhaul
Apr 2022	Unit 2 Overhaul
Apr 2023	Unit 3 Overhaul
Sep 2022	Sump System Overhaul
Sep 2022	Spillway Controls Replacement
Apr 2024	Unit 4 Modernization
Aug 2024	Control Room Remodel

Yearly Transfer to Plant:

2018	$3,750,000
2019	$5,500,000
2020	$250,000
2021	$21,100,000
2022	$8,050,000
2023	$7,600,000
2024	$8,300,000
Total	$45,750,000

Strategic Alignment:

Long Lake Plant Upgrade

The Long Lake Plant Upgrade aligns with the Safe and Reliable Infrastructure company strategy. The program will address safety and reliability issues while looking for innovative, economical ways to deliver the projects.

Customers and Stakeholders:

Manager, Hydro Operations and Maintenance

Manager, Spokane River Hydro Operations

Chief Operator, Long Lake and Little Falls HED

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Long Lake Plant Upgrade Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 20170417
Print Name: Jacob Reidt
Title: Mgr Contract & Project Mgmt
Role: Business Case Owner

Signature: Date: 4/19/2017
Print Name: Andy Vickers
Title: Dir Gen Prod Sub Support
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Brian Vandenburg	03/22/2017	Steve Wenke	04/10/2017	Initial Creation

Template Version: 02/24/2017

Nine Mile Rehabilitation

1 GENERAL INFORMATION

Requested Spend Amount	$ 119,044,755
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Failed Plant & Operations

1.1 Steering Committee or Advisory Group Information

The Steering Committee for the Nine Mile Rehabilitation governs the scope, schedule, and budget requests made by the stakeholder group when creating the deliverables and requirements for any sub projects. Each project may have the same, partial, or different members as selected by the Program Steering Committee. In general, Power Supply is represented by its Direction, Generation is represented by its Director, and Hydro Licensing & Environmental is represented by its Director.

2 BUSINESS PROBLEM

Both Units 1 and 2 at Nine Mile have mechanically failed, and are no longer able to generate electricity per our FERC license. These issues are a result of aging equipment, reservoir sedimentation, and damage to submerged equipment from the sediment. A FERC license amendment has been received to replace these units. In addition to the loss of generation for customers, failure to return the units to service may put the existing Spokane River License at risk. Requirements for Renewable Energy Credits (RECs) as part of Avista's Resource portfolio make this an opportune time increase REC availability, restore the powerhouse to full capacity and rehabilitate the surrounding facility.

3 PROPOSAL AND RECOMMENDED SOLUTION

Following the failure of Unit 1, Unit 2, and the subsequent turbine failure in Unit 4, an assessment of the Spokane River Plants was performed to establish the prudency of work within the Spokane River, prior to commencing work at Nine Mile. Many alternatives were generated, including:

- Rehabilitation or new construction of powerhouse at Post Falls
- Construction of new powerhouse at Upper Fall
- Construction of new powerhouse or spillway modification at Monroe Street
- Rehabilitation or new construction of powerhouse at Nine Mile
- Rehabilitation or new construction of powerhouse at Long Lake

Nine Mile Rehabilitation

A Likert Scale was developed by the team to evaluate each alterative against the following criteria.

- Alternative Development
- Financial
- Energy
- Regulatory Influences
- Operation and Maintenance
- Transmission System Impact
- Stakeholders
- Risk Identification
- Customer and Community Impact

Following the group evaluation of all proposed alternatives, the Project Team determined the only plant that warranted further evaluation at that time was Nine Mile due to the failed equipment, and ongoing operational and maintenance issues at the 100 year old facility. Focusing on the Nine Mile plant allowed for further evaluation of and reduced the number of fully evaluated alternatives to two:

Option	Cost	Start	Complete
Do nothing	$ 0		
Replace Units 1 and 2, rehabilitate Units 3 and 4, and modify the Sediment Bypass System	$ 70.8	2012	2019
A new five-unit 60 MW powerhouse located on the same footprint as the existing powerhouse, which would be demolished.	$ 192.7	2012	2027

Based on the criteria used by the Project Team to evaluate the Nine Mile Alternatives, Replacement of Units 1 and 2, rehabilitation of Units 3 and 4, and modify the Sediment Bypass System received the best score primarily due to project economics and likelihood of regulatory agency approval. Do nothing was eliminated due to the risk to our licenses.

The recommended alternative consists of a series of steps or phases, beginning in November 2012 and continuing through 2019. The key elements are:

Unit 1 and 2 Upgrade to Seagull Turbines:

- Units, including Turbines, Bulkheads, Generators, Switchgear
- Control and Protection Package including Excitation and Governors
- Powerhouse including Station Service, Ventilation, Intakes
- Substation and Communications work
- Site Work including cottages and warehouse
- Rehabilitate Intake Gates and Trash Rack

Unit 3 and 4 Overhaul:

- Overhaul including Runners, Thrust Bearings, Switchgear

- Control and Protection Package including Excitation and Governors
- Rehabilitate Intake Gates and Trash Rack

Plant Rehab

- Sediment Bypass and Debris Handling System
- Rehabilitation of the existing 100 year old Powerhouse Building

At completion, the powerhouse production capacity will be increased, units will experience less outages and reduced damaged from the sediment, and the failing control components will be replaced. Spending is expected to occur between 2012 and 2019.

2012	$10,758,313
2013	$10,794,355
2014	$26,059,264
2015	$26,890,094
2016	$13,628,862
2017	$11,800,000
2018	$8,575,000
2019	$7,322,000

A complete evaluation of this alternative's review, the analysis process, and the risks associated with the each is available in the attached material. Construction of a new powerhouse was eliminated due to lengthy permitting efforts, and increased risk surrounding unknown construction efforts.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Nine Mile Rehabilitation Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 20170417

Print Name: Jacob Reidt

Title: Mgr Contract & Project Mgmt

Role: Business Case Owner

Signature: Date: 4/19/2017

Print Name: Andy Vickers

Title: Dir Gen Prod Sub Support

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Nathan Fletcher	03/28/17	Steve Wenke	04/07/2017	Initial version

Template Version: 02/24/2017

Noxon Station Service

1 GENERAL INFORMATION

Requested Spend Amount	$3,810,118
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsors	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Investment Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The advisory group for this project consists of members from the Generation Production and Substation support department including the Director of GPSS, the Manager of Hydro Operations & Maintenance, and the Manager of Electrical Engineering for GPSS. Advisors are provided with monthly project status reports but, are only convened in the event of a necessary decision point.

The project/stakeholder team meets on a more regular basis (at least monthly) to work on the project's scope, schedule and budget. The project/stakeholder team is comprised of representatives from the various engineering groups (electrical, controls, mechanical) and operations.

2 BUSINESS PROBLEM

All generation facilities require Station Service to provide electric power to the plant. Station Service components include Motor Control Centers, Load Centers, Emergency Load Centers and various breakers. Station Service is an elaborate system with multiple built-in redundancies designed to protect the plant's electrical operation.

Upgrades and replacement of some of the Noxon 480V Station Service equipment have occurred since the late 1990s. However, some of the planned projects were never completed. In the fall of 2013, both an overcurrent coordination and load flow study[1] were completed for the Noxon 480V Station Service in response to an electrical overcurrent coordination issue. These studies found that a majority of the components require replacement due to electrical capacity and rating issues stemming from the added loads at the plant and the growth of the electric system in the 50 years of service.

[1] These studies can be made available upon request.

This project seeks to create a more reliable Station Service system in order to avoid forced outages and to modernize the electrical delivery system in the plant. Additionally, this effort will provide remote operation and monitoring capabilities, incorporate previously incomplete service expansions, support future system expansion, improve operator safety and ensure regulatory compliance.

If no action is taken, there is a risk of catastrophic switch gear failure and generator unit forced outages for up to a year. Additionally, forced load shedding under certain operational scenarios could be necessary.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Alternative 1 - Replace overrated and marginal function equipment and cables	$3,110,118	12/2013	10/2017
Alternative 2 Install Current Limiting Reactors	$800,000	12/2013	10/2017
Alternative 3 Install a new station service source from outside the plant (feeder extension)	$4,000,000	12/2013	10/2017

Do Nothing: doing nothing is an option. However, if components do fail, due their age, replacements are not available. Addressing such failures in an emergency/ad hoc situation would increase the cost and extend the outage time. This option does not provide any capacity for future loads.

<u>Alternative #1</u> would replace the following components:

- Station Service Transformers A & B
- 2000A Bus Ducts from Station Service transformers to Power Distribution Centers A & B
- Power Distribution Centers A & B
- Tie Bus that connects Power Distribution Centers A & B
- Main supply breakers to Motor Control Center 1, 2 and 3 and installing new monitoring and control of Motor Control Center starters
- Complete replacement of Motor Control Center 4
- Install a Programmable Logic Controller (PLC) to monitor and control Station Service from a central operating room.
- Integration of 1000 kVA Emergency Generator into Programmable Logic Controller monitoring and control

- Upgrade the existing Emergency Load Center to integrate with the balance of the station service system
- Address arc flash rating and improve load flow analysis and coordination Add metering to each Station Service Power Center and Emergency Generator.

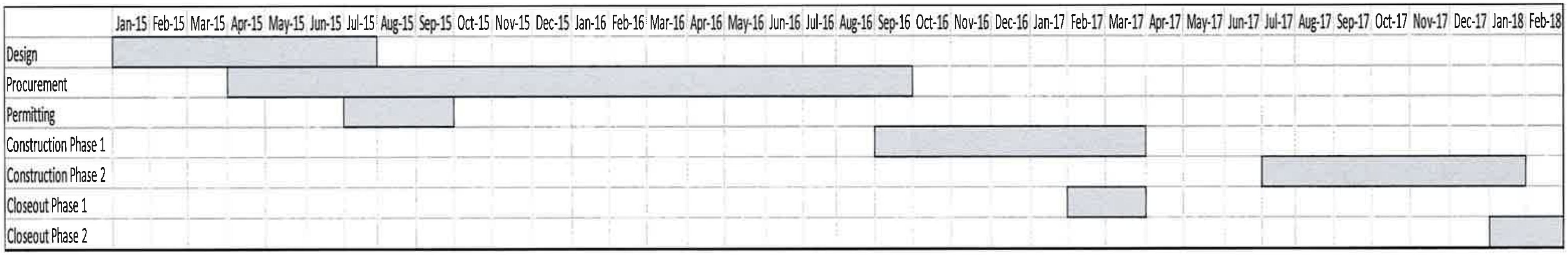
Alternative #2 involves the installation of current limiting reactors on the transformers which would address the breaker sizing issues but, would not address the reliability and expansion components required by the project objectives. As such, it was dropped from consideration.

Alternative #3 would bring in an external source for Station Service which would achieve the reliability objective, but would not address the anticipated future load requirement on MCC4. As such, it was dropped from consideration.

The recommended approach is alternative #1. This project aligns with both Avista's Safe and Reliable Infrastructure goal through investment to achieve optimum life-cycle performance and operational safety and Reliable Resources goal to control a portfolio of resources that responsibly meet our long term energy needs. Additionally, alternative #1 provides an avenue for prudent procurement of capital components by engaging in the competitive bid process.

This project impacts our external customers by ensuring they have predictable, affordable power. When units go offline unscheduled, we are forced to purchase power on the open market and/or produce power with our less cost effective generating facilities. These alternatives come at the risk of higher and/or unpredictable power costs per MWH for both our customers and shareholders.

Noxon Station Service



Alternative #1 Program Cash Flows

	Capital Cost	O&M Cost	Other Costs	Approved
Previous	$ -	$ -	$ -	$ -
2015	$ 343,228	$ -	$ -	$ 343,228
2016	$ 2,177,106	$ -	$ -	$ 1,477,106
2017	$ 1,171,577	$ -	$ -	$ 1,171,577
2018	$ 118,208	$ -	$ -	$ 118,208
2019	$ -	$ -	$ -	$ -
2020+	$ -	$ -	$ -	$ -
Total	$ 3,810,118	$ -	$ -	$ 3,110,119

NOTE: $700k in additional funds requested in Q4 2016.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Noxon Station Service Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	20170417
Print Name:	Jacob Reidt		
Title:	Mgr Contract & Project Mgmt		
Role:	Business Case Owner		

Signature:		Date:	4/19/2017
Print Name:	Andy Vickers		
Title:	Director - GPSS		
Role:	Business Case Sponsor		

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Terri Echegoyen	4/14/17	Steve Wenke	4/14/17	Initial version

Template Version: 03/07/2017

Peaking Generation Business Case

1 GENERAL INFORMATION

Requested Spend Amount	$500,000 per year
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Thomas Dempsey
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Failed Plant & Operations

1.1 Steering Committee or Advisory Group Information

This business case request is for Avista's Peaking Generation thermal plants, Boulder Park Generating Station, Northeast Combustion Turbine and Rathdrum Combustion Turbines. The purpose of this program is for these plants to keep their operating expenses as low as possible and to ensure start and operating reliability is achieved by providing funding for specific efforts to allow the plants to accomplish that objective.

Smaller and emergent projects planned for these facilities are identified and prioritized during monthly maintenance meetings, and approved by the Manager of Thermal Operations and Maintenance.

2 BUSINESS PROBLEM

Various projects for Boulder Park Generating Station, Northeast Combustion Turbine and Rathdrum Combustion Turbines are necessary to ensure continued safe, low cost, reliable and compliant electrical generation for Avista's electric customers. Work includes replacement of items identified through asset management decisions and programs necessary to maintain reliable and low operating costs of these plants. At times these plants are needed by Avista's Power Supply and System Operations group to start and operate in an emergency situation, where the electrical output is needed in a short amount of time. There have been times that have been identified by plant operations and tracked by Avista's asset management metrics reports, where start reliability and forced outages occur on a higher than acceptable occurrance. Some projects under this business case are completed to improve the start reliability of these facilities. As this program proceeds, it is expected that forced outage rates and forced derates of these facilities will decrease to a level one standard deviation less than the current average resulting in more economic benefits for the project.

The projects that are opened under this business case are not known in advance. Most of the individual projects are small in nature and are required due to regulatory or environmental requirements, emergent safety items, or for continued reliable operation. Examples of recent expenditures under this program include:

- Boulder Park – Emission Programmable Logic Controller replacement – allows remote monitoring of air emission to remain compliant with permit. (regulatory or environmental)
- Boulder Park – Replace the start air compressors – air used for start up of the engines (reliable operation)
- Northeast Combustion Turbine – Replace start system air compressors – air used for start up of the turbine (reliable operation)
- Northeast Combustion Turbine – Add sewage holding tank – replace antiquated sewage management system (regulatory or environmental)
- Rathdrum Combustion Turbines – Replace the Carbon Dioxide fire extinguishing system controllers – system utilized in case of an emergency in the combustion turbine area (safety)
- Rathdrum Combustion Turbines – Continuous Emission Monitoring System replacement – used to monitor and record air emission when the combustion turbines are on line (regulatory or environmental)

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
As proposed	$500,000	Ongoing, required for operation		
Unfunded Program				

This program is necessary to sustain or improve the existing operating costs for Boulder Park Generating Station, Northeast Combustion Turbine and Rathdrum Combustion Turbines. Work includes replacement of items identified through asset management decisions and programs necessary to maintain reliable and low operating costs of these plants. The Peaking Generation Business Case is reassessed for adjustments on a 5 year cycle.

A 5 year historical graph of expenditures is attached to help assess future capital funding for the Peaking Generation plants. This spending pattern indicates the diligence that is applied to capital request as managed by the Peaking Generation management team. As mentioned above, there is opportunity to adjust this amount every five years.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Peaking Generation Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Thomas C. Dempsey Date: 04/21/2017

Print Name: Thomas Dempsey

Title:

Role: Business Case Owner

Signature: Andy Vickers Date: 4/19/2017

Print Name: Andy Vickers

Title: Director, GPSS

Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Mike Mecham	04/07/2017	Jacob Reidt	04/17/2017	Initial version

Template Version: 02/24/2017

1 GENERAL INFORMATION

Requested Spend Amount	$58,100,000- +/- 30%
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The Post Falls HED Redevelopment program is monitored by a steering committee consisting of the Director of Environmental Affairs, the Director of Generation Production and Substation Support, the Director of Power Supply, and the Vice President of Energy Resources. This group is provided quarterly updates on project cost and schedule status. This group is also included in decisions on significant changes in scope.

The program is actively overseen by a stakeholder group that consists of representatives from Power Supply, Ass6et Management, Licensing and Environmental, and Generation & Production. This group meets at least monthly to receive progress reports, cost and schedule updates, and is presented with project risks and proposed mitigations to those risks. This group is also included on decisions on significant and modest changes in scope.

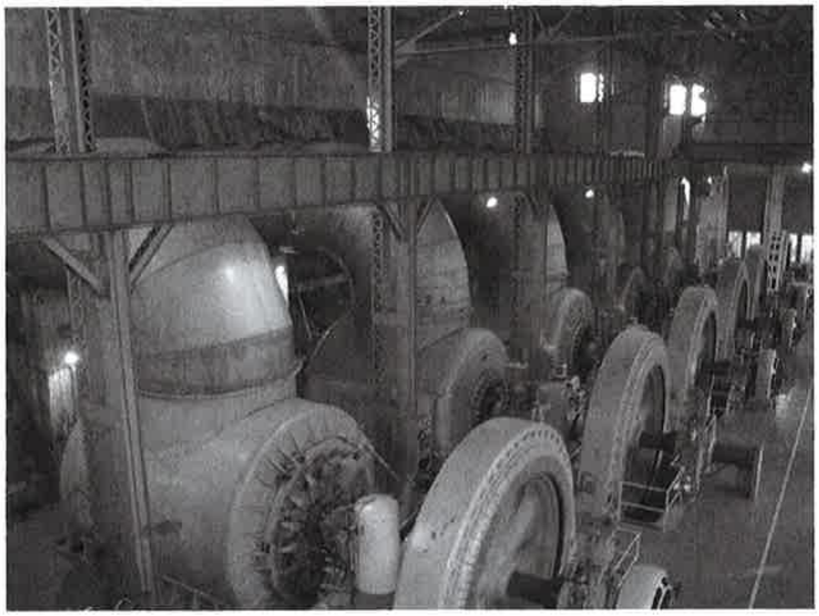
The project is led by a Project Manager. The Project Manager (PM) has a team of subject matter experts (SME) in a variety of areas to help them execute the project plan. Under the management of the PM and SME's, weekly and daily decisions are made to determine the most prudent course of action and to actively monitor progress of the project.

This PM is also assisted by an Advisory Group consisting of GPSS Engineering Managers, Maintenance Managers, and other administrative GPSS support personnel.

2 BUSINESS PROBLEM

The Post Falls HED started operation in 1906 and has been operating continually since that time. The generators, turbines, and governors (turbine speed controller) are original equipment and are still in service. The brick powerhouse with riveted steel superstructure is has not changed since the plant was constructed. Over time, it has been re-roofed and the intake area has had some major work, but the appearance of the project remains largely the same as when it started operation more than 110 years ago.

Photo showing interior of present Powerhouse



While the plant is still producing, the generating equipment, protective relaying, unit controls, and many other components of the operating equipment are mechanically and functionally failing. The turbines are estimated to be 50% efficient contrasted to modern turbines which can exceed 90% efficient. The existing governors have had patchwork repairs due to lack of replacement parts and while they do allow for unit control, they are ineffective in their response to system disturbances. Generator voltage controllers, protective relays, and unit monitoring systems all have a similar story of marginal functionality.

The units are exhibiting signs of failure. Attached are recent reports for Unit 1, Unit 4 and Unit 6 that describe some of the problems encountered during last maintenance on Unit 1, and the current operational directive to de-rate Unit 4 and Unit 6 due to their mechanical condition.

Because of the age of the plant, it presents some safety issues that have evolved over time. The access port for crews to access and maintain the turbine runners is too small to allow for any type of backboard or stretcher to exit the turbine area in the event a worker would be injured. The castings used to create the turbine water case do not allow the opening to be increased without risk of permanently damaging the water case and leaking. For this reason, crews can no longer access the turbines to maintain the runners. This has been the case for nearly a decade.

Photo showing safety issue due to restricted access to turbine area
The opening will not allow a backboard or stretcher to the area for emergency evacuation

Additionally, control modifications done in the late 1940's place the primary generator breakers inside the control room. This presents and unacceptable arc flash hazard to operating and maintenance personnel. While either the operation desk or the switchgear can be relocated to address this issue, this work would cost several million dollars and would not address some of the other issues associated with the plant.

Photo showing proximity of switchgear to Operators Station
(Operator Chair is indicated by arrow)

Finally, the Post Falls project has a number of critical operational requirements that support key recreational facilities, fishery, and other FERC license requirements. The Post Falls dam must provide minimum flows during summer months to support fishery habitat downstream. It is also subject to restrictions on how fast the flows through the project can change in order to meet downstream flow requirements. The present plant controls marginally provide the precision needed for this control.

To address water quality issues during high river flow seasons, unit and spillway controls must follow certain procedures to minimize Total Dissolved Gas creation in the river system. In addition, flows through the project provide water at the recreational site known as Trailer Park Wave. Upstream of the dam is the Spokane River and Lake Coeur d'Alene which are significant regional recreational resources that rely on the water control at Post Falls to maintain the water levels during the summer months.

Finally, there is a City Park and boat launch that is integral with the immediate upstream reservoir. Safety requirements have been implemented that require all spillgates at the project be closed before boaters are allowed to use the boat launch and recreate in the reservoir immediately upstream. Flows that would normally go through the plant need to be passed through the spillgates instead because of the unreliability of the generating units, extended maintenance outages, unit de-rates, and forced outages. This requires the boat launch opening to be delayed or in some cases closed on an emergency basis until flows subside or the generating unit can be returned to service.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
1. Remove the existing six generating units and equipment and replace them with new units, control and monitoring equipment, and balance of plant equipment. This is to be done within the present building structure.	$58.1M	2017 and going forward		

The estimates in the above table for capital costs should be construed to be +/- 30% for each of the options.

In an effort to determine a prudent course of action to address the Post Falls project, a significant Assessment Study was performed. This assessment considered a number of different options that might address the issues described above. The report of this assessment is attached to this document. This assessment concluded that the most prudent course of action was to redevelop the site by keeping the existing powerhouse and location.

Subsequently, a Feasibility Study was undertaken to evaluate different alternatives that could be done to redevelop the existing powerhouse. These include replacement of the present units with some new parts and pieces and modernizing the plant to the extent possible. It also considered a full redevelopment which would effective remove all of the existing equipment and replace it with new – still retaining the existing powerhouse structure. This Feasibility Study recommended that the project be redeveloped by shutting down the plant, removing the old equipment, and replacing it with new. This report on the Feasibility Workshop is attached to this document.

Finally, a team of Avista made up of personnel from the GPSS department, Licensing and Environmental, Power Supply, Asset Management, and Procurement convened a series of meetings to analyze the results of the Feasibility Study recommendation and explore its conclusions and assessed how the recommended solution addressed the issues such as equipment reliability, personnel safety, and risks associated with potential disruption of fishery and recreational needs. Significant financial analysis was performed by the Power Supply group in support of this effort to ascertain the most attractive alternative that addressed the issues. This was summarized in a final presentation in April of 2016. This was presented to the steering committee identified above. That presentation is attached to this document.

The final conclusion of all of this effort recommended that a full replacement of the existing units and other powerhouse equipment be replaced in their entirety with new equipment. It was estimated that the project would cost $58,100,000 (+/- 30%). It was also demonstrated that due to a shorter construction period, it is more beneficial to shut down the plant during this reconstruction. It was estimated the entire project would take five years once it was initiated. This decision was recorded in a summary message to a group of stakeholders and is attached to this document.

This work will replace the existing six 110 year old generating units with six new variable blade turbine generator units. Work will also include needed ancillary replacements and powerhouse remediation to attain a 50 year lived project. In addition, the efficiency of the new generating equipment will result in an improvement in output capacity and energy. This project will result in an estimated 40% increase in capacity and 15% increase in energy and reduce future major maintenance costs.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Post Falls HED Redevelopment Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 2017 04 19
Print Name: Jacob Reidt
Title: MGR CONTRACTS & PM
Role: Business Case Owner

Signature: Date: 4/19/2017
Print Name: Andy Vickers
Title: Director, GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Steve Wenke	04/19/2017	Jacob Reidt	04/19/2017	Initial version

Template Version: 02/24/2017

Certified Rebuild D10R CAT Dozer

1 GENERAL INFORMATION

Requested Spend Amount	$ 700,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Greg Wiggins
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

The plant uses a plant Budget Committee to evaluate, prioritize, and oversee project work at the station. This group consists of the Plant Manager, General Foreman, Plant Mechanic and a Plant Technician.

This project was first identified by plant mechanics and equipment operators. Using past maintenance logs along with an assessment on the current status of the machine a Project Request was submitted to the plant Budget Committee for a rebuild on the major components.

The plant Budget Committee utilizes an in-house Maintenance Project Review scoring matrix. The review process focuses around Personnel and Public Safety, Environmental Concerns, Regulatory/Insurance Mandates, Ongoing Maintenance Issues, Decreasing Future Operating Costs, Increasing Efficiency, Managing Obsolete Equipment and Assessing the Risk of Equipment Failure.

The Maintenance Project Review scoring matrix revealed risks around Safety, Ongoing Maintenance, Decreasing Future Operating Costs and Equipment Failure.

The project request and detailed estimate was brought forward to Corporate Finance and Planning Analyst for further analysis. The project was then presented to the Thermal Operations and Maintenance Manager for plant budget approval.

Approved projects are assigned a project Lead from the plant staff depending on discipline. Large complex projects may be assigned Engineering staff and/or a Project Manager from Generation Production and Substation Support Department to oversee. Project status and updates are discussed at the weekly plant maintenance meetings.

2 BUSINESS PROBLEM

Kettle Falls Generation Station utilizes two D10 CAT dozers to move nearly 500,000 green tons of waste wood around the storage area each year. Two primary tasks the Fuel Equipment Operators use the dozers throughout the day for is moving new material out into the inventory storage area and bringing in waste wood fuel to be burned for the plant operations.

Certified Rebuild D10R CAT Dozer

The fuel yard operates 24-7 receiving wood waste from over 20 contracted sawmills. Semi-trucks move product out of the mills to the plant where the wood waste is moved via a conveyor system. The dozers move the material out from underneath the conveying system to the storage pile. If the dozers break down and material is not moved out from the conveying system, trucks will begin to back up in the yard and possibly create issues on HWY 395. On average the plant receives 60-80 semi-truck loads of fuel each day from area sawmills. Maintaining the waste wood receiving equipment at the plant is critical to the plant overall operations. Other markets are available for waste wood such as beauty bark, wood pellets and press board. Having a highly reliable waste wood system keeps transportation costs down which benefits the customer in lower fuel costs to the plant.

The Fuel Equipment Operators also use the dozers throughout the day to move wood into the reclaiming system to be burned for the plant operations. The 53MW facility cannot operate on wood waste without the use of a dozer. The plant may be operated on natural gas at 50% capacity but is not classified as a renewable source and the REC's are lost when operating in that mode. The unit is less efficient and not designed to operate on natural gas for extended periods of time.

Normally one dozer is operating while the other is in standby until the 250 hour service is needed then the standby machine it put into service while the other sits in standby. Typically the dozer is operated 10-12 hours each day. On average each machine operates 2,000 hours per year.

Major overhauls require the dozer to be shipped over 80 miles to the nearest service center in Spokane. This work is planned and schedule around the annual maintenance outage in the Spring to reduce the risk to plant availability due to the loss of the standby dozer from an unexpected breakdown.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
1. *Rebuild the engine and transmission*	*$230,000*	*05 2017*	*06 2017*
2. *Purchase Certified Rebuilt CAT D10R*	*$700,000*	*05 2017*	*06 2017*
3. *Purchase New CAT D10 Dozer or equivalent*	*$1,800,000*	*06 2017*	*06 2017*

The plant has been operating and maintaining D10 dozers for over 30 years and has kept maintenance records of the equipment. Historical data on record over the past 20 years shows the engine on the D10R has never reached 9,000 hours of operation between failures. The transmission has never reached 10,000 hours of operation between failures. The CAT D10R dozer has over 36,000 operating hours on the machine chassis. Major components have been rebuilt over the years including the motor, transmission and final drives. The major rebuilds are planned on a time base maintenance plan. Minor components found in the auxiliary systems including radiators, coolers, hoses, belts, seals, gaskets, bearings, wiring, switches, gauges, tracks, pads, pins and blade are basically ran until failure.

Discussions with the equipment manufacture service representative identified three options to consider, major rebuild of critical components, a complete certified rebuild and purchase of new equipment.

The four options were discussed and doing nothing was not an option as the motor had failed and the transmission will fail at some point.

Option 1 is rebuilding the engine and transmission were identified as time based maintenance projects and funded as a Major Maintenance O&M project for 2017. There were uncertainties around what other issues we would find as we pulled the motor and transmission. There was risks the costs and scope could increase as auxiliary equipment including the final drives, steering clutches, brakes and minor equipment were removed and inspected.

The engine failed last Fall with 8,600 hours. We were given options of rebuilding our engine if the head was able to be machined down, purchase an already rebuilt engine or purchase a new engine. Rebuilding our engine would increase the time in which the plant would be operating with only one dozer available putting plant operations and fuel contracts at risk. Working with Western States we were able to negotiate a new engine with warranty for the same price of a rebuilt engine. A new engine was installed in October of 2016 for $119,000.

Option 2 is purchase the Certified Rebuilt CAT D10R dozer. The rebuilt dozer, which is currently an Avista Kettle Falls asset, will be completely disassembled down to the machine frame. All hoses, belts, seals, gaskets, bearings, wiring, switches and gauges will be new. The frame will be reconditioned to original performance of new machine. Engine and transmission will be reconditioned and updated to Caterpillar Certified Rebuild Standards. The dozer will be issued a new serial number and carry like new machine warranty.

Recommendation is to pursue option 2 to purchase a Certified Rebuilt CAT D10R dozer. The rebuild will be completed during the schedule annual maintenance outage and will be complete two weeks prior to the plant startup. Transfer to plant is scheduled to be June 2017. Because of the engine failure in $119k was spent in 2016, $500k will be spent in 2017. $230,000 will be reduced from K07 O&M for 2017 by eliminating the Major Maintenance project of the engine and transmission rebuild.

The Certified Rebuild on our existing D10R will reset the time based maintenance of the major and minor equipment. Reliability on the D10R will be increased as it will be back to like new condition. Steering and brakes will be like new making for safer operation on the fuel pile.

Western States Equipment has experience rebuilding equipment. The scope of work and costs for 2017 are attached.

Certified Rebuild D10R CAT Dozer

Option 3 is purchasing a new D10 CAT dozer or equivalent was considered but cost, long lead time and issues around operating our current D10T we eliminated this option. A new D10T was purchased in 2012 at the cost of $1.6 million for a new machine. Working with Western States a new CAT D10T dozer would now cost around $1.8 million. The D10T has newer emissions equipment which increased the exhaust temperature compared to the D10R. The extremely high manifold temperatures cause sawdust to catch on fire in the engine compartment throughout the hot summer months. Modifications to the D10T over the past years include large blowers moving sawdust off the top of the engine and ceramic coating the intake manifolds have reduced the fires on the D10T but not eliminated the problem.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Certified Rebuild D10R CAT Dozer Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Greg Wiggins Date: 4/17/2017
Print Name: Greg Wiggins
Title: Kettle Falls Plant Manager
Role: Business Case Owner

Signature: [signature] Date: 4/19/2017
Print Name: Andy Vickers
Title: Director of GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Greg Wiggins	04/12/2017	Jacob Reidt	04/17/2017	Initial version

Template Version: 03/07/2017

Cabinet Gorge Gantry Crane Replacement

1 GENERAL INFORMATION

Requested Spend Amount	$3,530,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsors	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Investment Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

Steering Committee members are comprised of: Director – GPSS, Manager, Hydro Operations & Maintenance and Manager - Project Delivery. Steering Committee members are provided a monthly project status report but, meet only in the event a decision point is needed.

Other key stakeholders include: Manager, Clark Fork River Hydro; Manager, Mechanical Engineering. Additional Cabinet Gorge Hydro Electrical Development mechanical staff that more directly represent the interests of the plant itself are consulted regularly.

2 BUSINESS PROBLEM

The gantry crane at Cabinet Gorge Hydro Electrical Development was used in the original construction of the plant in 1952-53. The crane is rated at 275 tons but can perform lifts as heavy as 330 tons on an occasional basis given that a certified test has been performed. As the asset has aged, various upgrades and updates have been made to prolong the crane's usefulness. However, it has become apparent that the crane is unable to perform the duties required of it in a dependable manner.

The gantry crane is of the only means of moving the large machinery found at Cabinet Gorge Hydro Electric Development such as moving/placing transformers, tailgates and generators. It is also the only way other equipment can be moved into and out of the plant. Its inability to function reliably impacts the work that is able to be performed at the plant and presents a safety risk to personnel if the crane fails to control the load. There is also a risk of not being able to accomplish repairs in the event of an emergency related to any one of the four generating units. In essence, the gantry crane is a bottle neck preventing both annual maintenance work and capital improvements alike.

The crane has a long history of breakdowns and operational problems. Most recently, during the Cabinet Gorge Unit #1 rehabilitation project spanning from 2014 to 2016, problems with the crane caused significant delays. Some examples include:

Relay/Contactor control problem – approx. 6 days

Gear/bearing problem – approx. 3 weeks

Brake problem – approx. 2 days

Additional problems experienced with the crane during the Unit #1 rehabilitation are documented in a memo by Ryan Bean, dated November 13, 2015, attached as Appendix A below.

Inspections performed by Professional Crane Inspections in the years 2010, 2012, 2015 and 2016 each give the crane an overall condition level 3 indicating that "Minor to moderate performance issues exist. PCI recommends repair or adjustment as soon as practical." Copies of these inspection reports can be made available upon request. A summarized list of foreman reports dating back to 1966 can be found in Appendix B below.

The successful outcome of this project would be to deliver a state-of-the-art crane capable of safely and reliably providing rated lifting capabilities for the likes of draft tube bulkheads, Generation Step-Up transformers and any one of the four generators.

A properly functioning crane at Cabinet Gorge Hydro Electric Development enables Avista to tend to the aging assets and maintenance needs of plant machinery to ensure that they run safely and reliably.

Customers benefit in the ability to adequately and safely maintain this equipment to continue to provide low cost and reliable energy.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Estimated Capital Cost	Start	Complete
Do nothing	$0		
Alternative 1: Full Replacement	$5,308,449	03/2017	12/2018
Alternative 2: Replacement w/extended reach	$7,272,000	03/2017	12/2018
Alternative 3: Refurbishment	$3,894,173	03/2017	12/2018

<u>Do Nothing</u>: doing nothing is an option however, given the criticality of this asset, doing nothing would leave the plant at risk should an emergency arise necessitating the crane's use

<u>Alternative #1</u>: Full Replacement. Advantages of this option include new structure designed and rated for 330T from conception, modernized controls utilizing current technology, reduced maintenance costs, elimination of as-building the existing crane structure, full archived drawing and product data set and removal of any lead-based paint and asbestos contamination risks.

<u>Alternative #2</u>: Replacement w/Extended Reach. This alternative expands on alternative #1 by utilizing extended reach to enable reach to the transformers and leg pass-through design enabling access to the draft tube bulkheads. Replacement with extended reach represents a modest increase (comparatively)

in price but will provide savings in terms of usability for the foreseeable future in terms of lifting capability. The estimated capital cost of $7,272,000 represents a very high level estimate at this point.

Alternative #3: Refurbishment. Advantages of refurbishment included lower up-front costs resulting from retaining the majority of the steel structure and a reduced level of demolition and installation work. However, this alternative would require lead-based paint and asbestos abatement and without X-ray examination of each rivet, it would be impossible to accurately and definitively assess the true condition of the structure.

A final decision has yet been made with regard to selection of Alternatives 1, 2, or 3. However, with any option we anticipate construction will take upwards of four months, following dismantling of the existing crane. Due to weather conditions inherent in north Idaho, it would be optimal to construct the new crane during the months of June to September. Given the long lead time expected in the manufacturing of a new crane (upwards of twelve months), we anticipate that all construction will be completed and the project placed in service no later than December 31, 2018.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Cabinet Gorge Gantry Crane Replacement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: [signature] Date: 20170417
Print Name: JACOB REIDT
Title: MGR CONTRACTS & PM
Role: Business Case Owner

Signature: [signature] Date: 4/19/2017
Print Name: Andrew Vickers
Title: Director GPSS
Role: Business Case Sponsor

VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Terri Echegoyen	4/14/2017	Steve Wenke	4/14/2017	Initial version

Template Version: 03/07/2017

APPENDIX A

DATE: NOVEMBER 13TH, 2015

TO: FILE, JACOB REIDT, RANDY PEIRCE, BOB WEISBECK, MIKE SHOFF

FROM: RYAN BEAN

SUBJECT: CABINET GORGE UNIT 1 – GANTRY CRANE ROTOR PICK PROBLEMS

Background

The scope of work during the Unit 1 rehabilitation included two picks of the generator rotor complete with field poles installed. The first pick removed the rotor from the stator and placed it in the shop for field pole removal. The rotor was then moved to the rotor storage building until the field poles were returned after being refurbished by RPR Hydro (subcontractor to GE). The field poles were reinstalled in the rotor storage building and the rotor was then placed back in the stator.

An Engineered Pick Plan was produced in accordance with ASME Code Section B30.2-3.1.7 that allows for occasional picks for loads exceeding rated limits up to 125% of the nameplate rating. The crane nameplate is 275 tons with an occasional pick of up to 343.8 tons. The rotor with lifting device weighs approx 330 tons. The cranes ability to lift this load was confirmed by Bedford Crane during the initial installation. The code allows an occasional pick not to exceed two occurrences in a 12 month period provided the crane manufacturer or other qualified person has reviewed the crane design to handle the load.

Inconsistencies During Operation

During the initial removal of the rotor from the stator, the micro drive and main hoist motor were used. The micro drive operated as expected, however the main hoist motor appeared to struggle when initially engaged. While returning the rotor to the stator on September 22nd, 2015, an issue was experienced where the main hoist did not operate as expected during raising. This was a repeatability issue with the main hoist where the hoist may raise, stall, or lower the rotor when the control lever was taken back into the same notch repeatedly. The lift was stopped and an investigation followed.

Investigation and Troubleshooting

With assistance from PCI and K&N Electric, an investigation and troubleshooting of the power and control systems followed. Components checked included the control lever, overloads, contactors, resistors, motor currents, brakes, and micro-drive operation. Everything appeared to be operating correctly, albeit in an overloaded condition due to the above nameplate load. The micro-drive operated reliably throughout testing. This lead us to believe the problem resides downstream of the control system, potentially with either the motor output or mechanical drive system. The gear train was visually inspected via available access ports and appeared to be in good shape and operated smoothly.

Original records of the hoist motor test data indicate the existing hoist motor reaches its nameplate current of 160 amps at a load of approximately 205 tons. This limits the service cycle at 240 amps with a load of approx. 320 amps to approximately one to two minutes without overheating resistor banks. This would require several lifting and cooling off periods to complete the lift. This reflects what we experienced in the field with tripping of the overload relays during sustained lifting at approx. 250 amps.

The crane micro-drive arrangement was also inspected, which consists of an additional motor and speed reducer that can be clutched in or out as necessary. The arrangement utilizes the same main hoist drivetrain and brakes (with an additional motor brake) without using the main hoist motor. Per Mark Oney's crane evaluation dated May 10, 1994 and design drawings, the micro-drive is rated for continuous duty without overheating. Hoisting speed is reduced during operation to slightly less than 0.5 feet per minute.

Conclusion

This has historically been a difficult pick for this crane and the system appears to have reached an impasse where the main hoist is no longer capable of producing the power to function at 100%. We suspect the issue lies in either the motor output, which has been operated above its nameplate current a number of times in the past, or due to an increase in mechanical drag in the gear train.

Per the results of our initial investigation and a stakeholder meeting on October 5th, 2015, (Ryan Bean, Andy Vickers, Mike Gonnella, Bob Weisbeck, Brand McNamara, Rob Selby, and Jeremy Winkle in attendance) and in agreement with the project Foreman Mike Shoff, the rotor pick was completed using the installed micro-drive system, without the use of the main hoist motor.

References

1. CG 1 Rotor Pick Plan Oct 2015 Rev1
2. ASME Crane code for CG1
3. Crane Report by Mark Oney, May 10 994
4. D-15701s001c1952 – Gantry Clearance Diagram with notes
5. 304E-25-040-01-01, 02, 03, 04, 05, 08 – Micro Drive Arrangement Drawings
6. 1952 Load Test Data
7. 1993 Load Test Data

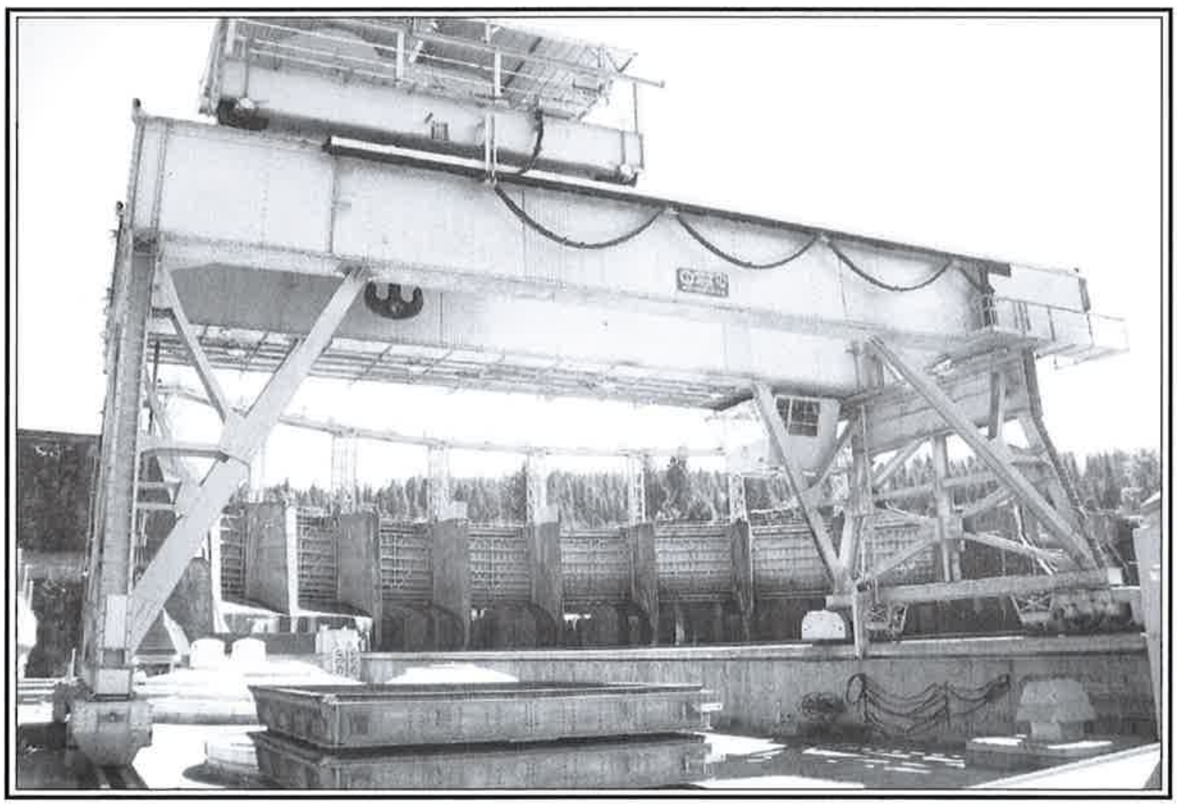
APPENDIX B: SUMMARIZED FOREMAN REPORTS

Job Title	Begin date	End date	Description
Gantry Crane - Mechanical Maintenance	5/23/1966	7/1/1966	Replaced sheaves and greased bearings on large hook. Applied oil to bearings on trolley. Drained and cleaned gear cases. Checked brakes.
Repair Gantry Crane	3/31/1969	4/9/1969	Large bevel gear was removed. New bushing was installed and the drive reassembled. Wheel guards were repaired and installed.
Re-reeve Gantry Crane Main Hook - Cabinet Gorge Station	12/2/1976	12/14/1976	Old cable was removed and new cable added to the drums.
Crane Maintenance	11/14/1988	11/14/1988	Main hoist gear box inspected. Friction brake assembly was seized together.
Redo Crane Track Splices	4/5/1993	5/13/1993	Weld holding rails together were repaired.
Gantry Crane - Bridge Drive Motor	1/23/1997	2/11/1997	The bridge drive motor on the Gantry Crane was removed and sent in for repair. Report includes repair details.
Crane Maintenance	6/28/1999	7/29/1999	The bridge motor, brake and gearbox were inspected. Trolley motor removed and sent to K&N for maintenance.
Annual Safety Inspection for Gantry Crane	7/12/2000	7/12/2000	Mechanical and Electrical inspection of crane components.
Crane Maintenance	5/1/2000	7/13/2000	Crane was pressure washed. Full structural inspection completed. Rusting areas noted. The main and auxiliary hoists were load tested.
Gantry Crane Maintenance "03"	6/16/2003	8/26/2003	Replaced all races and several bearings, and repaired sheaves of the main hoist block. Replumbed bridge brake system and repaired/replaced several brake components. Maintained the trolley controller (electricians), main and auxiliary hoist cables, and open

Cabinet Gorge Gantry Crane Replacement

Job Title	Begin date	End date	Description
275 Ton Gantry Crane Load Test	6/5/2006	6/8/2006	Components of the main hoist had been modified necessitating a load test (Report from load test on the 275 ton gantry cane).
Crane Maintenance 2010	9/15/2010	9/15/2010	Abbreviated maintenance on the gantry crane. See report for details.
Gantry Crane Oil Analysis	4/19/2011	4/19/2011	Oil Analysis results for Gantry Crane components.
Gantry Crane Maintenance 2011	4/11/2011	4/20/2011	Report includes details on maintenance of the gantry crane, checklist included. Report state the crane in in dire need of a paint job.
Annual Maintenance Gantry Crane	4/9/2012	5/3/2012	Crane condition regarding many items is not satisfactory, see report for details

detailed Foreman reports can be found here > c01m114/G://Foremanreports.accdb



Base Load Hydro

1 GENERAL INFORMATION

Requested Spend Amount	$1,149,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Mike Magruder
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

Most projects are proposed through Operations and Engineering. The projects are vetted holistically by Operations and Engineering to evaluate the issue, determine available options, confirm prudency, and bring the potential solutions forward for discussion with the Advisory Group consisting of the Plant Managers and the Manager of Hydro Operations. A similar vetting process is followed for funding emergency projects with the impacted stakeholders included.

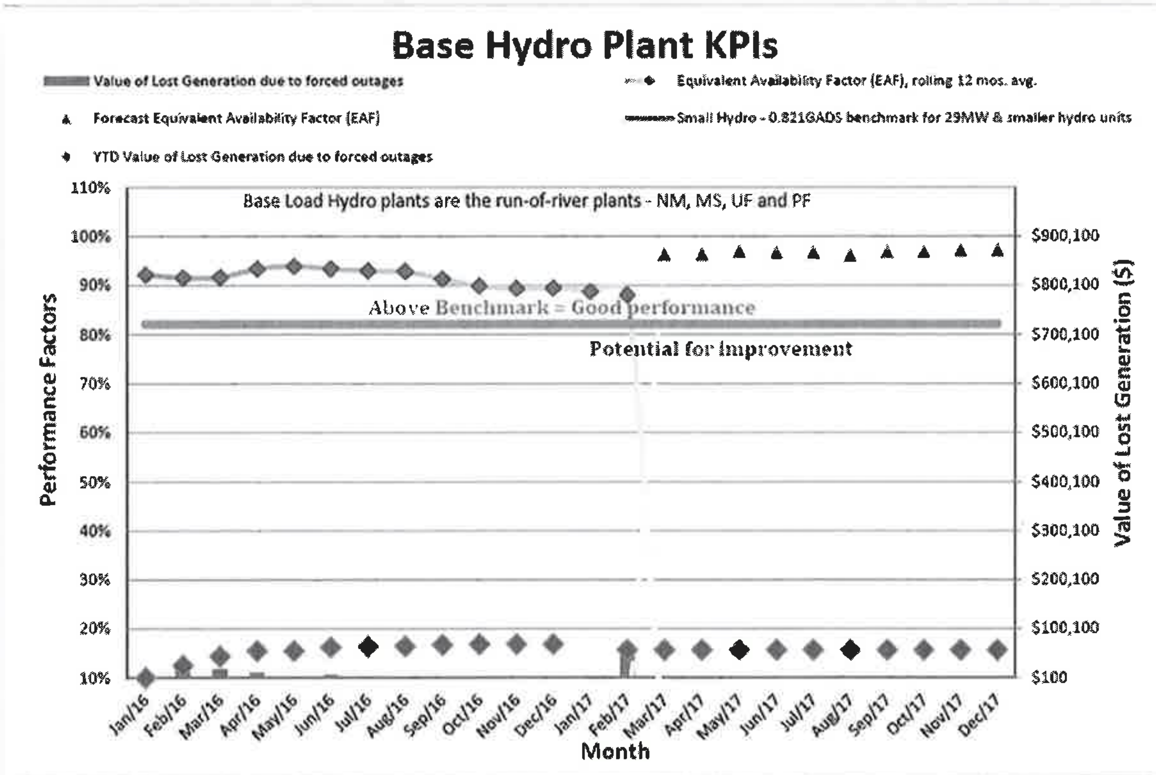
Over the course of the year, the program funding is actively managed by the Manager of Hydro Operations through monthly analysis and reporting for end of year expected spend.

2 BUSINESS PROBLEM

Avista's Base Load Hydro (or Base Hydro) program includes the Post Falls, Upper Falls, Monroe Street, and Nine Mile Hydroelectric Developments. These are all located on the upper Spokane River and are "run of river" plants which require them to have a constant water level in their forebay. It also includes minor capital projects at the Generation Control Center and on the Generation Control Network. It can also include some projects at the Post Street 115kV Substation where the two downtown hydro plants are tied into the grid.

The purpose of this program is provide funding for these plants to accomplish the objectives of keeping operating expenses as low as possible and maintain a level of reliability as indicated by the Equivalent Availability Factor (EAF) in the graph below. This program covers the smaller capital expenditures and upgrades required to safely and reliably operate the Upper Spokane River plants and continue their low cost. Projects completed under this program include replacement of failed equipment and small capital upgrades to plant facilities. The business driver for this program is a combination of Asset Condition, Failed (or Failing) Plant, and addressing operations deficiencies.. Most of these projects are short in duration, typically well within the budget year, and many are reactionary to plant operations issues.

Base Load Hydro

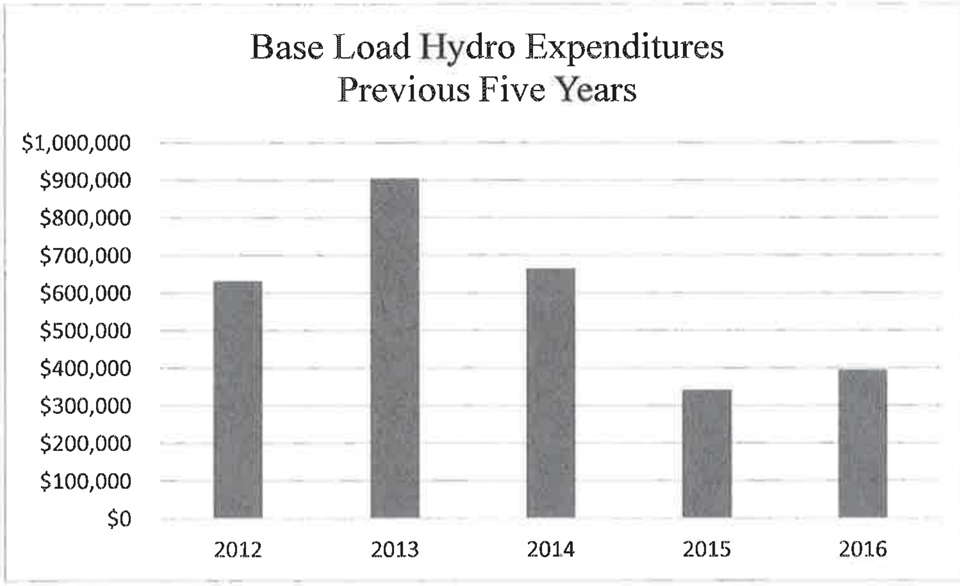


Examples of projects completed in 2016 or in progress under this business case include:

- Monroe St. – Water Drain and Diversion Installation. This project captured high flows on the site that were washing away some of the visitor amenities.
- Nine Mile – Replace Failed Spillway Gate Controls. This project will replace failed controls that allow the spillway to automatically adjust to maintain a forebay level.
- Upper Falls – Upgrade Headgate Camera. This replaced a non-functioning camera used for some area surveillance and to observe the trash rake operation on the intake.
- Post Falls – Replace Switch Building Drain Field. This project is to move ponding of water away from the foundation structure to maintain the integrity of the building.
- Nine Mile – Install Roof Safety Handrail. This addresses a personnel safety item.
- Post Falls – Install N. Channel Downstream Warning System. This is a system that warns the public in the event of a start of a spill or a significant increase in spill at the site.

The Program funding requests are submitted to the Capital Planning Group (CPG) through the business case review process. The business case expenditures over the last 5 years are shown below.

Base Load Hydro



2012	2013	2014	2015	2016
$631,961	$905,557	$664,783	$342,194	$394,849

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Maintain Existing Base Hydro Program Business Case	*$350k - $1.15M*	*Annual*	*Annual*
Make all small projects as standalone projects	*$3.1M - $5.9M*	*Annual*	*Annual*

These base load hydro plants are among the oldest plants in Avista's generating fleet. The option to "Do Nothing" is impractical in that existing machinery and systems periodically fail and are required to be replaced. Having no costs allocated to address those concerns is impractical.

The second proposal is to continue with the Base Hydro program business case as it is intended for asset condition, failed plant and operations. The program is actively managed and the vetting process considers all options for projects including doing the project under maintenance, the Base Hydro program, or a specific project business case.

The last proposal to eliminate funding for this program introduces greater risk to the ongoing operation of the plants by reducing the efficiency of operations and administration to set up and execute the required projects, especially for failed plant and operations. The program gives us the flexibility to respond quickly and prudently.

The recommended option to pursue is the second proposal to continue with the Base Hydro program business case as it is intended for asset condition, failed plant and operations. The program is actively managed and the vetting process considers all options for projects including doing the project under maintenance, the Base Hydro program, or a specific project business case. The program offers greater efficiency to manage "drop-in" or emergency projects allowing for better response time.

The annual requested budget amount is conservative to cover potential large expenditures that do not require a new project business case to be developed. The annual amount is reasonable, especially given that the program is actively managed and there is a means to release or request funds through the CPG.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Base Load Hydro Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Michael G. Magruder Date: 4/19/2017
Print Name: Michael Magruder
Title: Mgr. Hydro Ops & Maintenance
Role: Business Case Owner

Signature: Date: 4/19/2017
Print Name: Andrew Vickers
Title: Director, GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Mike Magruder	03/17/17	Jacob Reidt	04/19/2017	Initial version

Template Version: 03/07/2017

Baseload Thermal Program

1 GENERAL INFORMATION

Requested Spend Amount	$3,100,000 per year
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Thomas Dempsey
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Failed Plant & Operations

1.1 Steering Committee or Advisory Group Information

This business case request is for Avista's base load thermal plants, Kettle Falls and Coyote Springs 2. The purpose of this program is for these plants to keep their operating expenses as low as possible by providing funding for specific efforts to allow the plants to accomplish that objective.

Smaller and emergent projects planned for Kettle Falls are identified and prioritized through their plant Budget Committee. The plant Budget Committee utilizes an in-house Maintenance Project Review scoring matrix.

Projects planned specifically for Coyote Springs 2 are identified and prioritized during the Annual Budgeting process, with emergent projects discussed during the Monthly Owners committee meetings between Avista management and Coyote Springs management. Some of the projects that fall within this business case are joint projects between Portland General Electric (PGE) and Avista. Those "common" projects are also reviewed in an owner committee setting during meetings at the plant that take place on a monthly basis.

Individual projects are identified and approved by the Manager of Thermal Operations and Maintenance, specific plant managers and/or GPSS management. Some specific jobs under this program may require additional financial analysis if they are sufficiently large or there are several options that can be chosen to meet the objective. These projects are reviewed with finance personnel to make sure that they are in the best interest of our customers.

2 BUSINESS PROBLEM

Various projects for Coyote Springs 2 and Kettle Falls Generating Station are necessary to ensure continued safe, low cost, reliable and compliant electrical generation for Avista's electric customers. Work includes replacement of items identified through asset management decisions and programs necessary to maintain reliable and low operating costs of these plants. As this program proceeds, it is expected that forced outage rates and forced de-rates of these facilities will decrease to a level one standard deviation less than the current average resulting in more economic benefits for the Program. The projects that are opened under this business case are not known in advance. Most of the individual projects are small in nature and are required due to regulatory or environmental requirements, emergent safety items, or for continued reliable operation. Examples of recent expenditures under this Program include:

- Kettle Falls - Replace the Furnace Grate Drive System, part of the system that moves the burned fuel from the boiler to the ash disposal system (Reliability)
- Kettle Falls – Replace Furnace Forced Draft Fan motor, the fan that blows the wood waste fuel into the boiler where it is burned (Reliability)
- Kettle Falls – Diesel Fueling System, providing additional containment and system to improve the onsite diesel fuel handling system (Regulatory or Environmental)
- Kettle Falls – Replace the Turbine/Generator fire system (Safety)
- Coyote Springs 2 – Replace the Reheat Steam Attemperator, the system used to control the steam temperature in the boiler (Reliability)
- Coyote Springs 2 – Upgrade the Medium Pressure steam control valves (Safety and Reliability)
- Coyote Springs 2 – Upgrade the NOx analyzer, part of the plant emission monitoring system that monitors the Nitrous Oxide emissions (Regulatory or Environmental)
- Coyote Springs 2 – Improve physical site security, addition of key card access door locks on critical facility doors. (Regulatory, Safety)

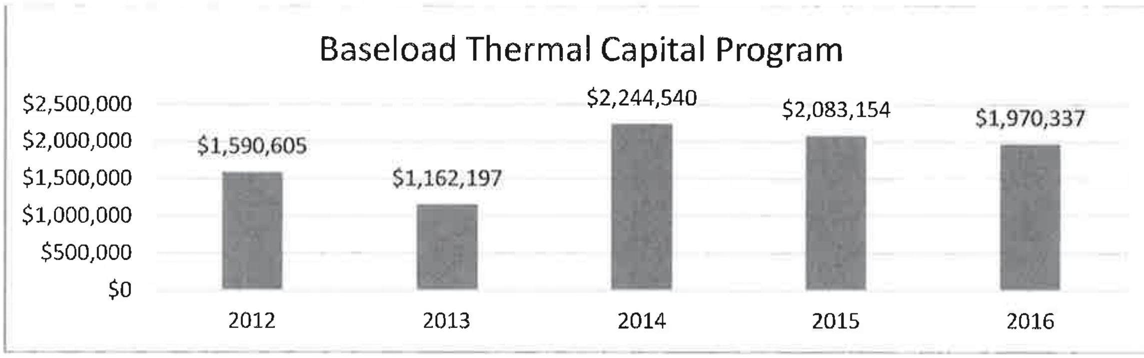
3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
As proposed	$3,100,000	Ongoing, required for operation		
Unfunded Program				

This program is necessary to sustain or improve the existing operating costs for Coyote Springs 2, the Coyote Springs Common Facilities, and Kettle Falls Generating Station. Work includes replacement of items identified through asset management decisions and programs necessary to maintain reliable and low operating costs of these plants. The Capital Retirement Unit Catalog for Kettle Falls and "Other" became effective January 1, 2017. Due to this Retirement Unit Catalog update, $900,000 in additional funds are necessary for 2017, in order to cover capital projects that were previously identified as Operation and Maintenance. The Base Load Thermal Business case is reassessed for adjustments on a 5 year cycle.

Baseload Thermal Program

A 5 year historical graph of expenditures is attached to help assess future capital funding for the Base Thermal Plant. This spending pattern indicates the diligence that is applied to capital requests as managed by the Kettle Falls plant Budget Committee and the joint owners of Coyote Springs during their monthly meetings. As mentioned above, there is opportunity to adjust this amount every five years if needed.



4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Baseload Thermal Program Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Thomas Dempsey Date: 4/21/2017
Print Name: Thomas Dempsey
Title:
Role: Business Case Owner

Signature: Date: 4/19/2017
Print Name: Andy Vickers
Title: Director, GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Mike Mecham	04/05/2017	Jacob Reidt	04/14/2017	Initial version

Template Version: 02/24/2017

Regulating Hydro

1 GENERAL INFORMATION

Requested Spend Amount	$3,533,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Mike Magruder
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

Most projects are proposed through Operations and Engineering. The projects are vetted holistically by Operations and Engineering to evaluate the issue, determine available options, confirm prudency, and bring the potential solutions forward for discussion with the Advisory Group consisting of the Plant Managers and the Manager of Hydro Operations. A similar vetting process is followed for funding emergency projects with the impacted stakeholders included.

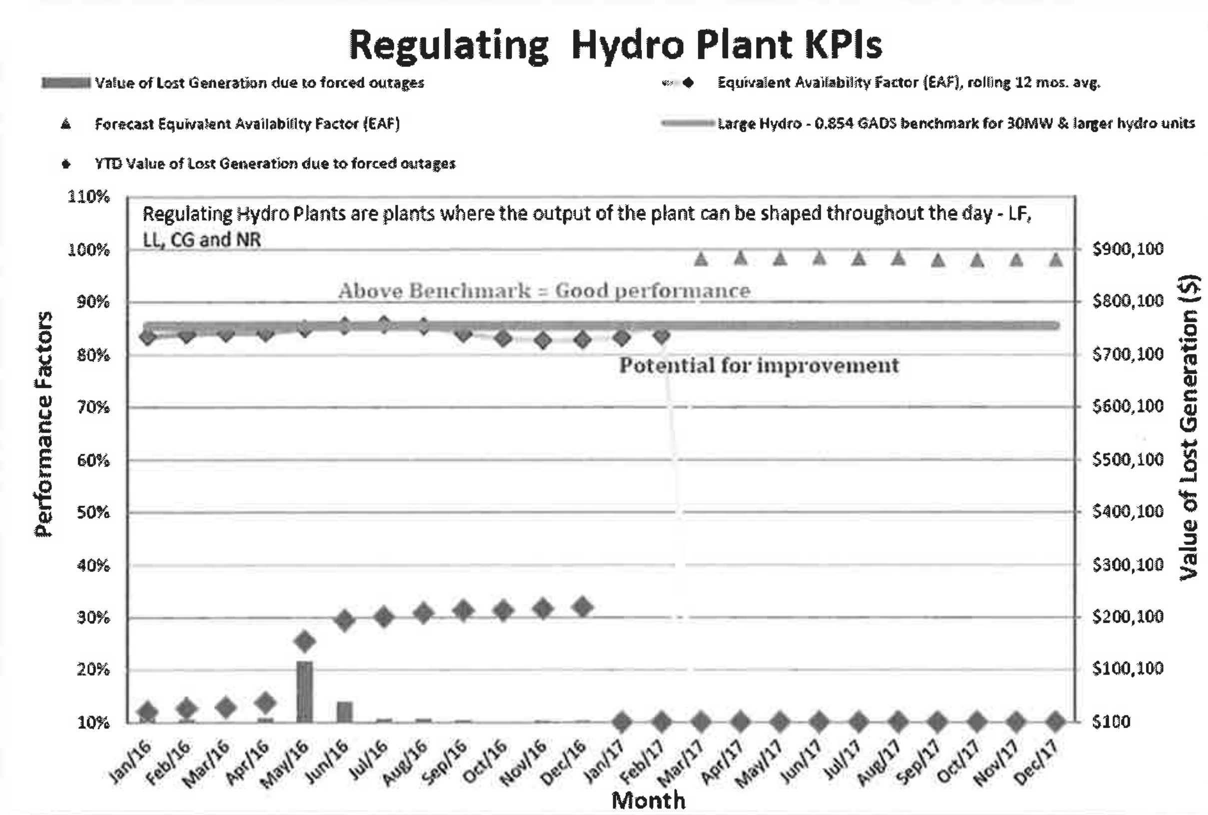
Over the course of the year, the program funding is actively managed by the Manager of Hydro Operations through monthly analysis and reporting for end of year expected spend.

2 BUSINESS PROBLEM

Avista's Regulating Hydro program includes the Cabinet Gorge (Idaho) and Noxon Rapids (Montana) Hydroelectric Developments on the Clark Fork River and the Long Lake (WA) and Little Falls (WA) Hydroelectric Developments on the lower Spokane River. Because of the storage available in their reservoirs, these plants are operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match the changing system loads, and other types of services necessary to provide a stable electric grid and to maximize value to Avista and its customers. These plants are the four largest hydro plants on Avista's system representing more than 950 MW of power.

Because these plants are used to provide a wide variety of grid services, energy and power supply, and other types of electric grid support services, the availability for the generating units in these plants is paramount. The purpose of this program is to provide funding to achieve availability targets (Equivalent Availability Factor or EAF) of 85% or higher.

Regulating Hydro



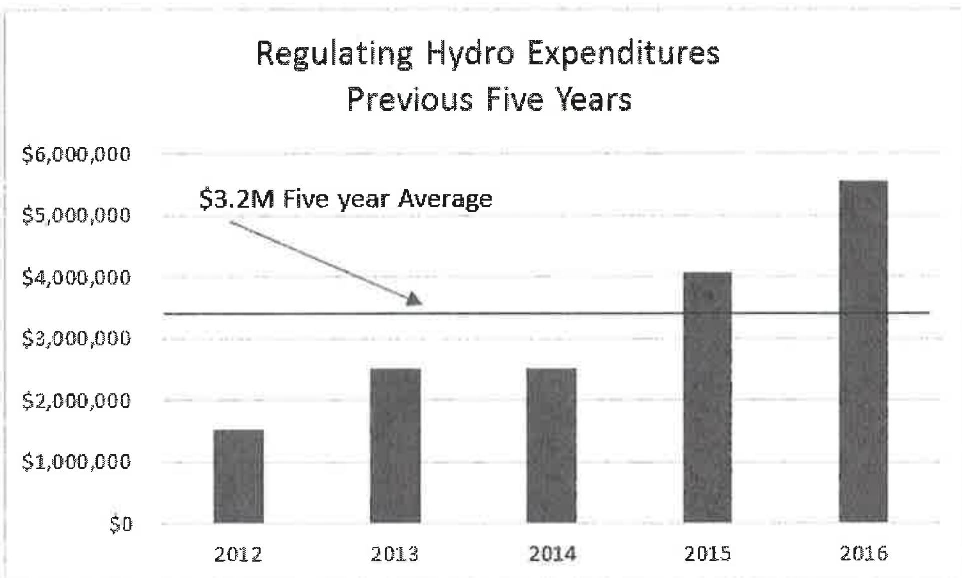
This program covers the smaller capital expenditures and upgrades required to safely and reliably operate four largest hydro plants and to achieve the EAF target. Maintaining these plants safely and reliably provides our customers with low cost, reliable power while ensuring the region has the resources it needs for the Bulk Electric System. Projects completed under this program include replacement of failed equipment and small capital upgrades to plant facilities. The business driver for this program is a combination of Asset Condition, Failed (or Failing) Plant, and addressing operations deficiencies. Most of these projects are short in duration, typically well within the budget year, and many are reactionary to plant operations issues.

Examples of projects completed in 2016 or in progress under this business case include:

- Cabinet Gorge – Tunnel Access Improvement; this work removed loose rock along the access road and installed protective metal netting to address the hazard of falling rocks on personnel and equipment. (Rock Scaling/Netting)
- Noxon – Install Dam Pressure Monitoring System; this work provided specialized instrumentation so that operators and engineers can monitor the structural stability of the dam.
- Long Lake – Spillway Improvements; this project replaced and enhanced some areas of the Long Lake spillway section by removing and replacing areas of the decaying 100 year old concrete. (Rebuild Parapet Wall/Extend Spillway Walkway)

- Little Falls – Replace Spillway Log Boom; this is a plant safety system that diverts floating debris from the generating units and can provide a boundary to keep the public away from the hazardous intake area of the dam.
- Noxon – Replace Unit 5 Turbine Bearing Cooling System
- Long Lake – Install Redundant Spillgate Hoist System; this work added a FERC required secondary system so that in the event of a failure of one system, the spillgates could still be operated with a second power source to assure ability to manage river flows at the project and provide safe operation of the spillway.

The Program funding requests are submitted to the Capital Planning Group (CPG) through the business case review process. The business case expenditures over the last 5 years are shown below.



2012	2013	2014	2015	2016
$1,514,577	$2,517,815	$2,519,775	$4,073,698	$5,558,100

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing – not a viable option.	$0		
Maintain Existing Regulating Hydro Program Business Case	*$1.5M - $5.5M*	*Annual*	*Annual*
Make all small projects as standalone projects	*$3.1M - $5.9M*	*Annual*	*Annual*

The plants that make up the Regulating Hydro group provide the most flexibility of any of the generating assets owned by Avista. As such, they provide a wide variety of critical and economical services that allows Avista to optimize the entire energy portfolio. Consequently, the option of doing nothing to maintain these units is a poor economic choice on behalf of Avista's customers and shareholders.

The second option is to continue with the Regulating Hydro program business case as it is intended for asset condition, failed plant and operations. The program is actively managed and the vetting process considers all options for projects including doing the project under maintenance, the Regulating Hydro program, or a specific project business case.

The last option to eliminate funding for this program introduces greater risk to the ongoing operation of the plants by reducing the efficiency of operations and administration to set up and execute the required projects, especially for failed plant and operations. The program gives us the flexibility to respond quickly and prudently.

The recommended option to pursue is the second proposal to continue with the Regulating Hydro program business case as it is intended for asset condition, failed plant and operations. The program is actively managed and the vetting process considers all options for projects including doing the project under maintenance, the Regulating Hydro program, or a specific project business case. The program offers greater efficiency to manage "drop-in" or emergency projects allowing for better response time.

The annual requested budget amount is conservative to cover potential large expenditures that do not require a new project business case to be developed. The annual amount is reasonable, especially given that the program is actively managed and there is a means to release or request funds through the CPG.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Regulating Hydro Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Michael A. Magruder Date: 4/19/2017
Print Name: Michael A. Magruder
Title: Mgr. Hydro Ops & Maintenance
Role: Business Case Owner

Signature: [signature] Date: 4/19/2017
Print Name: Andrew Vickers
Title: Director, GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Mike Magruder	03/17/17	Jacob Reidt	04/19/2017	Initial version

Template Version: 03/07/2017

Colstrip 3&4 Capital Projects

1 GENERAL INFORMATION

Requested Spend Amount	$10-$20 Million per year
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Thomas C Dempsey
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Program
Driver	Asset Condition

1.1 Steering Committee or Advisory Group Information

This Business Case request is for Colstrip 3&4 capital projects. Avista does not operate the facility nor does it prepare the annual capital budget plan. The current operator provides the annual business plan and capital budgets to the owner group every September. They also provide individual project summaries which characterize the work using categories similar in concept the Avista business case drivers. Avista reviews these individual projects. Some of them are reclassified to O&M if the work does not conform to our own capitalization policy. Avista does not have a "line item veto" capability for individual projects but it can present concerns during the September owners' meeting. Ultimately, the business plan is approved in accordance with the Ownership and Operation Agreement for units 3&4 that six companies are party too. This Business case represents the final approved budget after subtracting items that we will expense instead of charging to capital.

2 BUSINESS PROBLEM

This Business Case represents the entire body of capital work performed in a calendar year at Colstrip. This includes a variety of types of projects that Talen (current operator) characterizes using the following categories:

- ENVMD- Environmental Must Do
- Sustenance
- Regulatory
- Reliability Must Do

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete	Risk Mitigation
Ongoing Operations (Yes/No Vote)	$10-$20M		N/A	

Colstrip 3&4 Capital Projects

Colstrip Capital is required as part of ongoing operations of the facility.

- *The operator (Talon) reviews each proposed project. Discretionary items are reviewed in a hurdle rate analysis.*
- *The operator reviews the risk mitigation for each alternative using the business risk worksheet as well as describe the nature of the risks for each alternative.*
- *Those that meet the criteria are submitted as part of an overall budget to the owner committee,*
- *This process is repeated annually*
- *The annual business plan is available on request.*
- *Although alternatives are not available for consideration at this level, individual projects are reviewed and considered by all the joint owners. Projects may be delayed and changed per committee recommendation to the operator of the facility.*

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Colstrip 3&4 Capital Projects Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Date: 4/21/2017
Print Name:
Title:
Role: Business Case Owner

Signature: Date: 4/19/2017
Print Name: Andrew Vickers
Title: Director, GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Mike Mecham	04/17/2017	Steve Wenke	04/17/2017	Initial version

Template Version: 02/24/2017

1 GENERAL INFORMATION

Requested Spend Amount	$ 17,725,513
Requesting Organization/Department	Clark Fork License Implementation
Business Case Owner	Tim Swant
Business Case Sponsor	Bruce Howard
Sponsor Organization/Department	Legal
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

In mid-1996, stakeholders were invited to meet with a neutral facilitator to develop a process for participating in the relicensing of these projects. There evolved a Clark Fork Relicensing Team, which included representatives from nearly 40 organizations, including representatives from federal, state, and local government agencies, five Indian tribes, special interest groups, conservation groups, property owners, and Avista Corporation. The Relicensing Team established five technical working groups, covering: 1) fisheries; 2) water resources; 3) wildlife, botanical, and wetlands; 4) land use, recreation, and aesthetics; and 5) cultural resources management. The team developed protection, mitigation, and enhancement (PM&E) measures that were the basis for the comprehensive Settlement Agreement filed with Avista's license application. The Settlement Agreement establishes processes and includes 26 PM&E measures to resolve a wide range of complex and conflicting natural resource interests. Avista led this collaborative effort and signed the Agreement, making commitments for the 45-year term of the license. FERC incorporated the Settlement Agreement into the new license. Under the Settlement Agreement and license, the licensee works through a Management Committee (MC), comprised of one representative of each of the 27 parties to the Agreement, to implement the PM&E measures. In addition, the Clark Fork Settlement Agreement (CFSA) and license require Avista to provide funding for PM&E implementation over the course of the term.

All proposed PM&E activities and associated budgets are developed through one of the three technical working groups identified in the settlement agreement and approved by the MC, which strives to make all decisions, including approval of planned activities and expenditures, by consensus. FERC reviews and approves annual work plans to implement license requirements.

2 BUSINESS PROBLEM

Avista owns and operates the Noxon Rapids and Cabinet Gorge hydroelectric developments (Clark Fork Project No. 2058). The operation of the Clark Fork Project is conditioned by the Clark Fork Settlement Agreement, signed in 1999, and FERC

License No. 2058, effective date of March 1, 2001. Avista evaluated whether to proceed with a traditional licensing process in the 1990s, which typically led to conflict and litigation, or pursue a different strategy. The Company elected to pursue an agreement through a collaborative effort. During the negotiations, Officers and Directors of the company were informed and engaged, and officer approval was required for the Settlement. This business case represents the ongoing resolution of these issues and the means by which Avista fulfills its obligations under the CFSA and the FERC License.

The License was issued to Avista Corporation for a period of 45 years to operate and maintain the Clark Fork Project No. 2058. The License, and associated Code of Federal Regulation, includes hundreds of specific legal requirements, many of which are reflected in License Articles 404-430. These Articles derived from a comprehensive settlement agreement between Avista and over 20 other parties, including the States of Idaho and Montana, various federal agencies, five Native American tribes, and numerous Non-Governmental Organizations. We are required to develop, in consultation with the Management Committee, an annual implementation plan and report, addressing all PM&E measures of the License. In addition, implementation of these measures is intended to address ongoing compliance with Montana and Idaho Clean Water Act requirements, the Endangered Species Act (fish passage), and state, federal and tribal water quality standards as applicable. License articles also describe our operational requirements for items such as minimum flows, and reservoir levels, as well as dam safety and public safety requirements.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	0	N/A	
Fund the annual request	$17,725,513	01/2017	12/2017

Funding of the Clark Fork License Implementation is essential to remain in compliance with the FERC license and CFSA for permission to continue to own and operate the hydro-electric facilities. This commitment was made in 2001, and is ongoing. At that time, Avista determined that the Settlement was in the best interest of Avista, our customers, our shareholders, and the communities we serve. These decisions were documented throughout the process at that time.

If the PM&Es and license articles are not implemented and/or funded, we would be in breach of an agreement and in violation of our License. There would be high risk for penalties and fines, new license requirements, higher mitigation costs, and loss of operational flexibility of the Cabinet Gorge and Noxon Rapids Hydro Electric Facilities. Ultimately, FERC has the authority to revoke our operating license and we could risk a competing license or even losing the facility. Loss of operational flexibility, or, in the extreme, of these generation assets, would create substantial new costs, to the detriment of our customers and the company.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Clark Fork Settlement Agreement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ______________________ Date: __________
Print Name: ______________________
Title: ______________________
Role: Business Case Owner

Signature: [signature] Date: 4/17/17
Print Name: BRUCE F HOWARD
Title: DIRECTOR, ENV. AFFAIRS
Role: Business Case Sponsor

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Heide Evans	03/29/17	Bruce Howard	03/29/17	Initial version

Template Version: 02/24/2017

flexibility, or, in the extreme, of these generation assets, would create substantial new costs, to the detriment of our customers and the company.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Clark Fork Settlement Agreement Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: [signature] Date: 04/19/2017
Print Name: Timothy J Swant
Title: Clark Fork Licensee Manager
Role: Business Case Owner

Signature: [signature] Date: 4/19/17
Print Name: BRUCE F HOWARD
Title: DIRECTOR, ENV-AFFAIRS
Role: Business Case Sponsor

5 VERSION HISTORY

[Version #	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Heide Evans	03/29/17	Bruce Howard	03/29/17	Initial version

Template Version: 02/24/2017

Hydro Safety Minor Blanket

1 GENERAL INFORMATION

Requested Spend Amount	$350,000.00
Requesting Organization/Department	Hydro Compliance
Business Case Owner	Michele Drake
Business Case Sponsor	Bruce Howard
Sponsor Organization/Department	Legal
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

Funded projects are identified in several ways. During periodic site inspections, FERC staff may identify a new specific concern or point out an existing item that is deficient or in need of repair. In other cases, Avista has assessed the condition of safety items at our dams, and proactively plans replacement or addition of a new safety measure. Replacement can be driven by physical condition/age/function, changing standards in FERC guidance, industry practice, or emergent public safety needs. All projects are subject to the conceptual approval of the Chief Dam Safety Engineer and to additional internal review and oversight.

2 BUSINESS PROBLEM

Section 10(c) of the Federal Power Act authorizes the Federal Energy Regulatory Commission (FERC) to establish regulations requiring owners of hydro projects under its jurisdiction to operate and properly maintain such projects for the protection of life, health, and property. FERC's Division of Dam Safety and Inspections establishes national guidance and policy, and Regional Offices implement this responsibility. 18 CFR Part 12 delegates to the Regional Engineer the authority to require safety devices, where necessary. Section 12.42 of the Regulations states that, "To the satisfaction of, and within a time specified by the Regional Engineer, an applicant or licensee must install, operate, and maintain any signs, lights, sirens, barriers, or other safety devices that may reasonably be necessary or desirable to warn the public of fluctuations in flow from the project or otherwise, to protect the public in the use of the project lands and waters."

In addition to the broad regulatory discretion given to FERC, Avista is subject to liability should we not maintain safety-related equipment at our hydro facilities. This work is aimed at reducing both regulatory and liability risks. Some of the projects under this budget are planned, but others are opportunistic. We take advantage of other planned work to coordinate dam safety actions, and at times, we have to replace equipment that has been damaged due to flow conditions. [1]

Projects identified for 2017 include replacement of the boater safety cable at Noxon Rapids and replacement of a boater safety sign at Post Falls.

1. The boater safety cable at Noxon Rapids is more than 30 years old, and has begun to show visual signs of failure, including listing, rusted floats and deteriorating concrete. Operators and hydro safety staff identified the item as in need of repair or replacement.
2. The boater safety sign at Post Falls was installed in 1994 and utilizes neon, molded bulb lighting. A FERC inspector identified that the sign was becoming difficult to read, and informally suggested replacement. Upon investigation, some of the individual letters fail to illuminate.

In both cases, repair of the existing item was considered. However the age and condition of the items and improvements in technology have made repair moot.

1. "Guidelines for Public Safety at Hydropower Project" https://www.ferc.gov/industries/hydropower/safety/guidelines/public-safety.pdf

2. Avista's Hydro Public Safety Plans for each of it hydro facilities.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	0		
Fund annual request	$350,000	01 2017	12 2017

Funding of these activities protect employees, contractors, and the general public, and reduces financial risk to Avista.

Non-Funding activity would ultimately result in total failure of safety equipment, subjecting Avista to additional liabilities due to possible regulatory penalties, injuries or loss of life, and is therefore not a recommended option.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Hydro Safety Minor Blanket Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: ______________________ Date: __________
Print Name: ______________________
Title: ______________________
Role: Business Case Owner

Signature: [signature] Date: 4/17/17
Print Name: BRUCE F HOWARD
Title: DIRECTOR, ENV. AFFAIRS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Heide Evans	03/17/17	Bruce Howard	04/03/17	Initial version

Template Version: 03/07/2017

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Hydro Safety Minor Blanket Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Michele M. Drake Date: 4/17/17
Print Name: Michele M. Drake
Title: supervisor, hydro compliance services
Role: Business Case Owner

Signature: [signature] Date: 4/17/17
Print Name: BRUCE F HOWARD
Title: DIRECTOR, ENV. AFFAIRS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Heide Evans	03/17/17	Bruce Howard	04/03/17	Initial version

Template Version: 03/07/2017

Kettle Falls Water Treatment System

1 GENERAL INFORMATION

Requested Spend Amount	$4,750,000
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner	Jacob Reidt
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Category	Project
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

The Steering committee is comprised of the Manager of Thermal Operations & Maintenance, the Kettle Falls Plant Manager, the Manager of Contracts & Project Management, the Manager of Corporate Environmental Compliance, and the Manager of Mechanical Engineering for GPSS.

Monthly project status updates will be distributed via email indicating the status of the scope, schedule and budget of the project.

Steering committee meetings will be coordinated if decisions need to be made, due to significant changes to the scope, schedule or budget based on unforeseen circumstances and/or risk identification.

1.2 Customers & Stakeholders:

This projects impacts internally the Thermal Operations & Maintenance teams, including the crews at Kettle Falls, Mechanical Engineering and Environmental Compliance. By providing these stakeholders with a properly maintained water treatment system we are providing them with reliability of the system and regulatory compliance assurance.

This project impacts our external customers by ensuring we are in compliance with environmental regulations and protecting the public safety of ground water. We are also ensuring our customers have predictable, affordable power. When units go offline unscheduled, we are forced to purchase power on the open market and/or produce power with our less cost effective generating facilities. These alternatives come at the risk of higher and/or unpredictable power costs per MWH for both our customers and shareholders.

2 BUSINESS PROBLEM

Major Driver:

The water effluent discharged from the plant contains trace levels of mercury. To abate the mercury in the effluent, an expensive high quality food grade acid is added to the boiler water supply. With this treatment, mercury levels are not detectable.

In 2015, the water source for the plant was moved from the City of Kettle Falls to a new well system owned by Avista to reduce the water supply costs and to provide the City with needed additional capacity for their system. When this new water source was used for the plant, the water chemistry was different than the City Water source, leading to trace levels of mercury again. As with the previous effort, more of the expensive food grade acid was added to the treatment system. This again resulted in effluent with no detectable level of mercury.

While the current system meets the source and environmental needs, Kettle Falls Generating Station needs a more cost effective, long-term solution to achieve environmental permit compliance and to improve the water treatment process.

Kettle Falls is subject to the following regulatory drivers surrounding water treatment:

- Washington State Department of Ecology
  - National Pollutant Discharge System (NPEDS), 126 priority pollutants
  - Discharge water limits (into the Columbia River)

Currently, two intended short term solutions have been deployed to ensure environmental compliance with increasing and unsustainable operating costs. These two solutions have been evaluated to determine which best meets the cost effective, environmentally sound, long term solution being sought to best manage costs.

1. Use of high quality food grade acid
2. Rental/Test Reverse Osmosis (RO) system in place at one fourth (¼) of full operating capacity

Secondary Driver:
The present water treatment system has been in service since the plant went on line in 1983. The original water treatment demineralization system is aging. The two (2) demineralizer trains in service are controlled by the original automated control system or Programmable Logic Controllers (PLC's). Mechanical valves that control the water treatment are failing. The control system needs to be upgraded to a modern platform and the programming needs to be rewritten. Because of glitches with the existing control program, the system can get locked in step until it is reset which uses more chemicals and water, increasing operating expenses. The panel board for controlling the system has hardwired buttons/indicators that need to be replaced to allow soft control from a touch panel. The analyzers used are from a company that is no longer in business and replacement parts cannot be purchased. There is also a Caustic/Acid dilution rack that is seeing increasing corrosion on piping and valves need to be replaced. Overall the existing water treatment system needs an overhaul or replacement.

Risks:
The continued use of the food grade acid does abate the mercury in the effluent, but significantly increases O&M costs to run the unit. This treatment does not mitigate the performance risk associated with an aging/obsolete demineralization water treatment system. The current demineralization system requires a substantial amount of Plant Operator and Technicians time and effort to reset the system due to component and controls malfunctions. The system also requires corrective actions to fix pump, hose and valve leaks (see attached work order history).

Driving Metrics:

Through routine internal environmental testing we found that we were discharging trace amounts of mercury into the Columbia River due to acid and caustic chemicals injected into the cooling tower and boiler water purification treatment processes. The system is intended to bring these down to non-detectable levels of mercury.

Success Measures:

The Nalco DMS model will be run for any proposed water treatment system to ensure the system will meet our environmental requirements. The Nalco DMS model projects the outcome of water treatment solutions based on the quality and quantity of the incoming source water, and the quantity of chemicals introduced in the water purification process.

References/Studies:

- Department of Ecology – Self reported "Violation Letter", 1/20/2015
- URS Corporation – Mercury Source Review & Strategy Development, 2/12/2015
- Nalco, DMS – Water Treatment System Review, 7/16/2015
- Avista Maximo Water Treatment Work Order History

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Requested Start	Requested Complete	Risk Mitigation
Do nothing	$0	N/A		
Option 1 - Full Scale RO/EDI water treatment system	*$4.75M*	*02.2016*	*06.2018*	
Option 2 - Full Scale Water Treatment System TBD by vendor during RFP process	*$4.75M*	*02.2016*	*06.2018*	
Option 3 - Upgrade current demineralizer train	*unknown*	*02.2016*	*06.2018*	

Impacts:

While the Operations staff at Kettle Falls will need to be trained to operate the new water treatment system, no additional staff will be needed to meet the operational requirements. The water treatment system placed in service will be chosen based on O&M costs for treatment and other costs to repair or replace the existing water treatment system.

Alternatives:

1. The present system of food acid treatment only adds $30,000/ month incremental O&M expense to supply and manage this treatment. This can continue, however this option does not address the issues associated with the existing water treatment plant.
2. Installation of a new Reverse Osmosis (RO) and Electrodionization (EDI) water treatment system to replace much of the existing water treatment system, OR

3. Installation of an alternative water treatment system TBD by vendors during an RFP process that would replace much of the existing water treatment system, OR
4. Upgrade the current demineralizer train. Re-write the programming and move the control and monitoring to the existing plant control system. This option would also replace worn and non-performing valves and analyzers with new ones.

Risk Mitigation:

This project will improve the reliability of the treated water that is required for the boiler. It will also provide environmental compliance assurance by addressing mercury levels and other point source pollutants by upgrading or replacing or enhancing the water treatment system. Failure to find a long term, cost effective means to treat and provide water for the boiler could result in environmental compliance violations that could result in significant penalties and/or changes in permitting regulations with increased operating and capital costs to meet compliance.

Selected Alternative:

A selected alternative has not been determined at this time. The alternatives will be evaluated and a final solution will be determined.

Timeline:

- 2016 – Preliminary Analysis for RO/EDI Water Treatment System
- 2017 – Request for Proposal Process
- 2018 – In Service

Alignment with Strategic Initiatives:

Mandatory and compliance. The water treatment process needs to adhere to environmental regulations.

Safe and reliable infrastructure. The water treatment system is an essential operating system of the plant, failure of the system impacts operations.

Budget:

The rough +/- 25% estimate for the project is currently at $4.75M based on initial review conducted by Nalco for water treatment solution alternatives.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Kettle Falls Water Treatment System Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: [signature] Date: 20170417
Print Name: Jacob Reidt
Title: Mgr. Contracts & Project Management
Role: Business Case Owner

Signature: [signature] Date: 4/19/2017
Print Name: Andy Vickers
Title: Dir. GPSS
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Tara Moses	4/5/2017	Steve Wenke	4/10/2017	Initial version

Template Version: 02/24/2017

Spokane River License Implementation

I. GENERAL INFORMATION

Requested Spend Amount	$2,033,063
Requesting Organization/Department	Spokane River License Implementation
Business Case Owner	Speed Fitzhugh
Business Case Sponsor	Bruce Howard
Sponsor Organization/Department	Legal
Category	Mandatory
Driver	Mandatory & Compliance

1.1 Steering Committee or Advisory Group Information

Decisions related to annual implementation activities are reviewed and approved by technical working groups (i.e., fish, aquatic weeds, water quality, recreation, land use, and cultural) comprised of Avista, Tribal, local, state (Idaho and Washington), and federal agency staff. The activities are specific to the Federal Energy Regulatory Commission (FERC)-approved resource and operational plans that were developed to address Spokane River Project License conditions. Capital projects are undertaken only to meet the requirements of the Spokane River License.

II. BUSINESS PROBLEM

Avista must have a license from FERC to operate the Spokane River Project. The Spokane River Project consists of the Post Falls Hydroelectric Development (HED), Upper Falls HED, Monroe Street HED, Nine Mile HED and Long Lake HED. Avista's prior license expired in 2007; Avista undertook a relicensing effort beginning formally in 2002 to secure a new license, consisting of a collaborative process with over 200 stakeholders. The process ultimately resulted in FERC's issuance of a 50-year license to Avista to operate and maintain the Spokane River Project, No 2545, effective June 18, 2009. This License defines how Avista shall operate the Spokane River Project and includes several hundred requirements, through license conditions, that we must meet.

The License was issued pursuant to the Federal Power Act (FPA) and embodies requirements of a wide range of other laws (The Clean Water Act, The Endangered Species Act, The National Historic Preservation Act, etc.). These requirements are also expressed through specific license articles (known as Protection Mitigation and Enhancement Measures (PME)), relating to fish, terrestrial, water quality, recreation, land use, education, cultural and aesthetic resources.

Avista also entered into additional two-party agreements with local state, and federal agencies and the Spokane Tribe. Avista's FERC license and agreements include mandatory conditions issued by the Idaho Department of Environmental Quality (401 Water Quality Certification, issued June 5, 2008), the Washington Department of Ecology (401 Certification, issued May 8, 2009), the U.S. Forest Service (Federal Power Act 4(e), issued May 4, 2007), U.S. Bureau of Land Management, as well as commitments joined in with the Idaho Department of Fish and Game, Idaho Department of Parks and Recreation, City of Coeur d'Alene, and the City of Post Falls, Kootenai County Parks and Waterways, Washington Parks and Recreation Commission, the Washington Department of Natural Resources, and articles set forth in Form L-1 (entitled "Terms and Conditions of License for Constructed Major project Affecting Lands of the United States"). During the seven-year relicensing process, we engaged stakeholders in direct negotiations and we also engaged in litigation to challenge some proposed conditions. Avista's officers and Board were updated regularly during these efforts, and officers were engaged at key decision points. Ultimately, FERC retains oversight jurisdiction for license compliance; however, other entities, such as state agencies, assert their authority to independently enforce license terms. The FERC license ensured Avista's ability to operate the Spokane River project on behalf of our customers for another 50 years.

III. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	$0		
Fund the annual request	$2,033,063	01 2017	12 2017

Complying with our license is mandatory to continued permission to operate the Spokane River Project. Funding the implementation activities for the Spokane River Project License is essential to remain in compliance with the FERC license. There are no practicable alternatives to meet compliance. Avista evaluated the potential of surrendering the Spokane River license at the beginning of the relicensing process, determining that this option would be detrimental to our customers, the company, and the communities we serve.

If the PM&Es, license articles and settlement agreements are not implemented and/or funded, we would be out of compliance with and/or in violation of our License. This would lead to penalties and fines, new license requirements, court costs, higher mitigation costs, and loss of operational flexibility. Ultimately, FERC has the authority to revoke our License if we do not comply with the terms and conditions required by it. Loss of operational flexibility, or in the extreme, loss of our generation assets, would create substantial new costs to our customers and no benefits.

IV. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Spokane River License Implementation Business Case and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Speed Fitzhugh   Date: 4/19/17
Print Name: Speed Fitzhugh
Title: Spokane River License Manager
Role: Business Case Owner

Signature: Bruce Howard   Date: 4/17/17
Print Name: BRUCE F HOWARD
Title: DIRECTOR, ENV. AFFAIRS
Role: Business Case Sponsor

V. VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Heide Evans	03/15/17	Bruce Howard	3/30/17	Initial version

Template Version: 03/07/2017

Energy Imbalance Market

1 GENERAL INFORMATION

Requested Spend Amount	$12,000,000
Requesting Organization/Department	Power Supply
Business Case Owner	Scott Kinney
Business Case Sponsor	Jason Thackston
Sponsor Organization/Department	Energy Resources
Category	Project
Driver	Performance & Capacity

1.1 Steering Committee or Advisory Group Information

This project is a future effort that is being considered for implementation in April of 2021 with a start date of January 2019, so a steering committee does not yet exist. Prior to the start of project implementation a steering committee will be formed with representation from Power Supply, System Operations, Generation and Production, Enterprise Technology, and Resource Accounting. Until a formal steering committee is formed Scott Kinney and Mike Magruder will coordinate business case development and project schedule. The final decision of when to join the California Independent System Operator Energy Imbalance Market will be made by the Officer Team based on recommendations from Power Supply and System Operations in the fall of 2017.

2 BUSINESS PROBLEM

The California Independent System Operator Energy Imbalance Market is an in-hour hour economic based regional resource dispatch program that allows participants to lower energy costs by either dispatching less expensive resources to meet load obligations or increase revenue through the bidding of excess energy into the market. The Energy Imbalance Market dispatches the most economic resource across its entire market footprint based on bid prices to balance in-hour load and generation resulting in lower overall dispatch cost for each individual participant. The Energy Imbalance Market also lowers the amount of on-line regulation that each utility holds in excess every hour to make up the error between the forecasted load and resource plans, and what actually occurs during the operating hour. The reduced regulation can then be monetized creating additional revenue.

There are several factors that impact the timing for when Avista will join the California Independent System Operator Energy Imbalance Market. Avista will continuously monitor these factors throughout this year and plans to make a formal decision on when to join the market by the end of 2017.

Several northwest utilities (Pacificorp, Portland General Electric, Puget Sound Energy, Idaho Power, and Seattle City Light) along with other western utilities have either already joined the California Independent System Operator Energy Imbalance

Market or announced they will be joining in the next two years. This shift in market participation may impact daily market liquidity by reducing the number of available bi-lateral trading partners to conduct near term daily energy transactions. The risk of limited trading partners could drive daily market prices higher and/or cause reliability issues if energy can't be procured from the bi-lateral market during stressed conditions such as the loss of an Avista generating facility.

Another driver for joining the Energy Imbalance Market is the integration of additional renewable resources in the Avista Balancing Authority. Renewable generation requires additional regulation and load following to back up the intermittency of the resource. There is a tipping point where Avista's existing hydro flexibility can't sufficiently supply the required load following for the amount of renewable resources integrated into the Avista Balancing Authority. The Energy Imbalance Market allows for the expanded integration of renewable resources by providing a cost effective back stop market to balance intermittent resources. Currently Avista has only a single wind facility and limited solar facilities within its Balancing Authority so there is adequate hydro flexibility to follow these plants. However there are several third party independent power producers that are in the Avista transmission interconnection queue that are exploring integration. Also the new Washington State Clean Air Rule requirements could drive additional renewable integration to be built in our Balancing Authority. Finally Avista continuously receives requests from smaller solar and wind resources that are seeking Public Utility Regulatory Policies Act contracts. Any additional renewable resource integrated in Avista's service territory will result in a reduction of hydro flexibility to follow the resource and will be a factor in the timing of Avista joining the Energy Imbalance Market.

Avista continues to monitor the daily bi-lateral market trading and associated liquidity as well as the potential for additional renewable resource integration in our Balancing Authority. These are the primary drivers for when Avista will need to join the Energy Imbalance Market. The opportunity to lower resource dispatch costs based on estimated benefits verses the costs to join the market will also be evaluated and considered in the determination of the appropriate time for Avista to become an Energy Imbalance Market participant.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Do nothing	*$0*	*N/A*	*N/A*
California Independent System Operator Energy Imbalance Market	*$12.0 M*	*01 2019*	*04 2021*
Northwest Based Energy Imbalance Market	*N/A*	*N/A*	*N/A*

Power Supply is currently contracting with a consultant to perform a benefit analysis to determine the estimated value of joining the Energy Imbalance Market. The assessment should be completed by September of 2017. Based on other similar northwest utilities that have conducted benefit studies or are actually operating in the Energy Imbalance Market, Avista anticipates annual benefits of $3-5 M. The benefit analysis results will be used along with estimated project costs to create a full cost/benefit analysis to help inform the decision to join the market. After completion of the benefit study, the business case will be updated this fall and support the recommendation to the Officer Team regarding the appropriate timing for Avista to join the Energy Imbalance Market.

Power Supply hired a consultant (Utilicast) to develop a high level cost estimate to join the California Independent System Operator Energy Imbalance Market and is currently working with System Operations and ET to fine tune the estimates. The estimated costs to join the market is $15M up front and $3.0 to 3.5 M annually based on the gap assessment completed by Utilicast. The implementation effort includes new software applications, changes to existing software, generation controls and metering upgrades, contractors to assist with implementation, and internal resources including new employees to support on-going operations. Current estimates assume 30-35 Avista employees and five contractors will be required to support project implementation over a 24-30 month window. Not all estimated employees will be needed full time to support project implementation. In order to support the effort long term it is estimated that 11-13 additional full time positions will be needed including a new 24x7 operating desk in System Operations, an analyst in Power Supply, an accountant in Resource Accounting, a data support engineer, operations engineers, and technology support. Some of the needed on-going positions may be filled by changing work responsibilities instead of hiring new employees.

Based on other northwest utilities experience it will take 24-30 months to integrate into the Energy Imbalance Market. Currently the California Independent System Operator is only allowing two additional utilities to join the Energy Imbalance Market every year. With the current schedule of utilities deciding to join the market, the earliest Avista could join is April of 2021 and this date could move out to April of 2022 or 2023 pending the decision of additional utilities to join and the lack of operational and/or economic drivers for Avista as previously discussed. As a conservative place holder this project is being budgeted with a go-live date of April 2021. A recommendation on the project and go-live date will be finalized and presented to the Officer Team in the fall of 2017 after the cost benefit assessment is complete.

Based on the proposed 2021 implementation date the project and corresponding funding would begin in 2019 with a majority of work and spend occurring in 2020. The remaining work in the first quarter of 2021 will primarily be parallel operations and testing of functions to prepare for the April energization date. Current project funding estimates are based on an 80% capital and 20% operations and maintenance split for implementation costs. The split between capital and expense funding may be adjusted as we get closer to project implementation however the current estimate of 80% capital spend should be the highest capital funding level for the project.

Currently the only other option available to Avista with regards to joining a formal market is the do nothing option. In this case Avista will maintain current operations and look to optimize resources (buy and sell as needed) in the bi-lateral market to keep costs as low as possible. However if any of the market risks discussed above change significantly then Avista will probably need to join the California Independent System Operator Energy Imbalance Market to keep costs and market risks under control.

Dramatic growth in wind and solar generation introduces energy sources from which significant variations can occur due to change of weather conditions. The lack of bi-lateral trading partners can significantly increase resource costs or introduce the risk that energy cannot be obtained through bi-lateral trading when needed by Avista to balance near term generation and load requirements. An Energy Imbalance Market implements an automated system to efficiently dispatch resources across multiple balancing authorities in real-time for use as short-term balancing resources to ensure supply matches demand. This allows Energy Imbalance Market participants to voluntarily make available and take advantage of generation resources from across a much larger regional market. Without the Energy Imbalance Market, only generation resources within each balancing authority area can be used to cover short-term system imbalances which can be costly (i.e. firing-up a thermal peaker). Energy Imbalance Market makes it more economical to dispatch short-term balancing resources, and enables buying and selling of these resources across a regional basis.

There is a slight possibility that another market could form in the region but that is highly unlikely in the near term based on the recent failure of the Northwest Utility Market Coordination initiative that evaluated the design and implementation of a northwest specific Energy Imbalance Market. Avista participated in the Northwest Utility Market Coordination evaluation from 2012 to 2015 along with 18 other northwest utilities. Unfortunately a cost effective northwest market design could not be agreed upon resulting in northwest utilities joining the California Independent System Operator Energy Imbalance Market to meet their renewable energy balancing needs.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the **Energy Imbalance Market** project and agree with the approach it presents and that it has been approved by the steering committee or other governance body identified in Section 1.1. The undersigned also acknowledge that significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Scott Kinney   Date: 04/2017
Print Name: Scott Kinney
Title: Director Power Supply
Role: Business Case Owner

Signature: Date: 04/2017
Print Name: Jason Thackston
Title: Senior VP Energy Resources
Role: Business Case Sponsor

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	*Scott Kinney*	*04/12/17*	*Jason Thackston*	*04/12/17*	*Initial version*

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