BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-20_____

EXH. JRT-6

JASON R. THACKSTON

REPRESENTING AVISTA CORPORATION

Index for Business Case Justification Narratives Related to Major Generation Investments for 2018 and 2019

Little Falls Plant Upgrade

EXECUTIVE SUMMARY

The Little Falls Plant Upgrade Program began in 2012 and in 2020, is in the final phases of implementation. With three project components left (Plant Sump, Drain Field, and Panel Room Roof/Enclosure for the new controls equipment) the vast majority of the project scope has been completed and risks mitigated. The remaining work has very little risk exposure and minimal impact on the plant's current operations.

Driven initially by the age of the infrastructure at the plant, Alternative 3, a full replacement of all four generatring units and all obsolete supporting equipment, was selected, implemented, and put in service. Given as how the program is nearly complete and decisions have already been made in regards to the following, no additional details regarding solution recommendations, risk of failure to implement, schedule significance or benefit to customers are provided at this time.

The remaining programmed work is being scheduled into 2021 as a response to internal resource constraints, and therefore, this business case and its remaining activities are subject to this Business Case Refresh exercise.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Brian Vandenburg*	*Initial draft of original business case*	*2.14.17*	*Signed/approved*
1.1	*Kara Heatherly*	*Conversion to new format*	*6.20.20*	*Includes budget update*

GENERAL INFORMATION

Requested Spend Amount	$56,100,000
Requested Spend Time Period	10 years
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Brian Vandenburg | Andy Vickers
Sponsor Organization/Department	GPSS
Phase	Execution
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

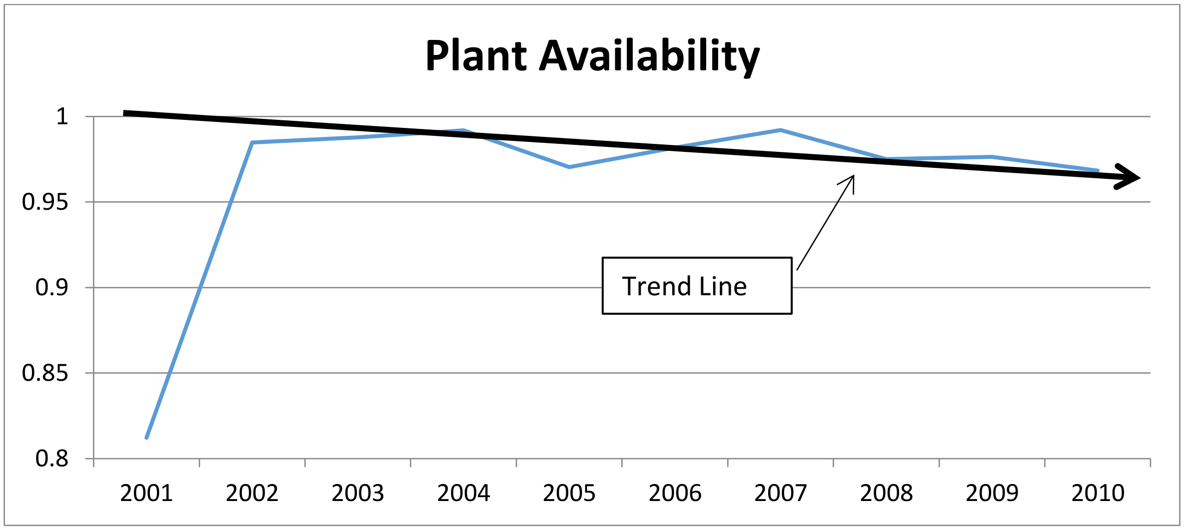
1.1 What is the current or potential problem that is being addressed?

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.

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.

1.2 Discuss the major drivers of the business case and the benefits to the customer

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.



1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

See alternatives analysis narrative conducted at project onset in section 2.1 for additional details.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

See alternatives analysis narrative conducted at project onset in section 2.1 for additional details.

Option	Capital Cost	O&M Cost	Start	Complete

Alternative 3: Preferred	*$56,100,000*	*$0*	*2012*	*2021*
Status Quo	*$0*	*$150,000/yr*		
Alternative 1	*$5,000,000*	*$20,000/yr*		
Alternative 2	*$83,000,000*	*$0*		

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

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.

Strategic Alignment:

Little Falls Plant Upgrade

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.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

In accordance with the detailed project schedule, annual projected capital expenditures for remaining scope are in accordance with the 5-year CPG budget table below.

Year	Requested Amount	CPG Approved Amount *(Admin use only)*
2021	$800,000	
2022	$0	
2023	$0	
2024	$0	
2025	$0	

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

No direct relationship exists between the other parts of the business and the completion of the remaining Little Falls program work. All integral connection points with other business units have already been made. Equipment upgrades have been performed to support other corporate priorities (such as EIM and HMI) and plant processes that are impacted by the remaining work are directly and appropriately involved in the planning and scheduling of that work in order to insure seemless integration with the plant.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

See alternatives analysis narrative conducted at project onset in section 2.1 for additional details. This project is in the closeout phase and budget is being adjusted into future years to respond to resource availability. Any remaining project risks will be mitigated at the project steering committee level for the remaining active program components.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

Milestone Schedule (reflective of original business case milestones):

January 2010 Program Begins

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

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Mission: This project safely, responsibility and affordably improves the level of service we provide to our customers by minimizing our exposure to potential, prolonged breaks in service.

Strategic Initiatives: 1. Safe and Reliable Infastructure, 2. Responsible Resources.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Prudency considers not only the likelihood of risk but the severity of the outcome in the event of failure. Prior to their upgrade, failure of these sytems could have been nearly immediately catastrophic. Minimizing the severity of non-preventable failure is the prudent and responsible thing to do.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Customers and Stakeholders:

Little Falls Plant Upgrade

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

3.1 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.

3.2 Provide and discuss the governance processes and people that will provide oversight

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 any 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.

More detailed project governance protocols will be established during the project chartering process whereby the Steering Committee will allocate appropriate resources to the management of all project activities, once better defined.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Project decisions will be made at the PM level where appropriate and escalated to the Project/Program Steering Committee when and if determined to be necessary by the definitions above. Regular updates will be provided to the Steering Committee by the PM team as project scope, schedule and budget are defined, and through the course of the project execution, change.

The undersigned acknowledge they have reviewed the HMI Control Software Business Case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: DocuSigned by: Brian Vandenburg 0304BE8BAF1D490... Date: Jul-10-2020 | 8:14 AM PDT

Print Name: Brian Vandenburg

Title: Manager, Hydro Operations

Role: Business Case Owner

Signature: DocuSigned by: Andy Vickers 8E5EBAFEABB04AA... Date: Jul-10-2020 | 8:30 AM PDT

Little Falls Plant Upgrade

Print Name:	Andy Vickers		
Title:	Director of GPSS		
Role:	Business Case Sponsor		
Signature:	DocuSigned by: Scott Kinney 50D41B164A9B4...	Date:	Jul-13-2020 | 5:56 AM PDT
Print Name:	Scott Kinney		
Title:	Director of Power Supply		
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

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

Nine Mile Rehabilitation

- 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: Jacob Reidt Date: 20170417

Print Name: Jacob Reidt

Title: Mgr Contract & Project Mgmt

Role: Business Case Owner

Signature: Andy Vickers 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

Index for Business Case Justification Narratives Related to 2020 Pro Forma Plant Group Generation Capital Additions

Cabinet Gorge 15kV Bus Replacement

1 GENERAL INFORMATION

Requested Spend Amount	$1,200,000
Requesting Organization/Department	GPSS
Business Case Owner	Glen Farmer
Business Case Sponsor	Andy Vickers
Sponsor Organization/Department	GPSS
Category	Project
Driver	Performance & Capacity

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 will consist the Hydro Operations and Maintenance Manager, Project Delivery Manger and the Maintenance Management and Construction Manager.

2 BUSINESS PROBLEM

- During the design of the Cabinet Gorge Station Service Project, we had planned to raise this horizontal bus by 5 feet to allow for the Station Service equipment to be installed within these bus rooms.
- Further investigation is was discovered that the main horizontal bus between the generators and the GSU transformers was underrated compared the generator and circuit breaker ratings by approximately 10%.
- This led to the development of the replacement bus alternative to upgrade the 15kV bus to 4,000 Amps to be consistent with the generator machine ratings and GCB ratings.

3 PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Total Cost including Outages	Start	Complete
Do nothing	$0			
Replace the 15kV Bus A (2021) and Bus B (2022)	$1,200,000	$1,230,000	10/2020	12/2022
Raise the existing 15kV Bus A (2021) and Bus B (2022)	$1,400.000	$1,700,000	10/2020	12/2022

Cabinet Gorge 15kV Bus Replacement

Two of the major design requirements for the Cabinet Gorge Station Service Project are contributing factors that has led to the development of this new 15kV Bus Replacement Project:

- Build as much of the new station service system as possible while the existing station service equipment remains in service. The benefit of this construction approach will greatly reduce generation unit outages from several months to just a few weeks.
- Remove oil-filled equipment from the outdoor powerhouse deck. This requirement is based on the extensive amount of water that the powerhouse deck receives during spill season with the modified spillways now in service for TDG abatement and is intended to reduce risk of potential oil spills.

This approach requires that we find new locations for the planned station service equipment. The Station Service Project Team's recommendation was to use the bus rooms at Cabinet for installing the new dry-type station service transformers and the Power Centers to help minimize unit outage time and also removes the existing oil filled station service transformers off the deck.

In order to be able to use the bus rooms at Cabinet, we need to move the existing 15kV bus. We did look at just removing and replacing a section of bus to allow the equipment to be moved into the bus rooms. However, this option would not provide adequate safe working clearance around the equipment if the bus remains in its current location, and was disregarded as a viable alternative.

In order to resolve this issue of moving the 15kV generator bus to install the proposed station service project equipment in these bus rooms, we evaluated two alternatives: 1.) Raising the existing 3,000 Amp bus; and 2.) Replacing the bus with a new 4,000 Amp bus.

Alternative 1.) Raise the existing 3,000 Amp 15kV bus. This alternative was not chosen based on the following:

- Highest cost alternative
- Requires up to an 8 week outage for two units. Outage time is rather long as we would have to remove all of the bus sessions in 7 foot sections, install new structural steel hangers. Then re-install all of the bus section by section. Then add the vertical transition boxes to connect to the existing generator disconnects and GSU B-Phase bus.
- Does not resolve concerns over existing bus being marginally rated.
- Has a higher level of risk with damaging the aged brown glass insulators during disassembly and reassembly of the bus sections.

Cabinet Gorge 15kV Bus Replacement

- Has a higher level of seismic risk as this existing equipment was not designed to today's seismic standards.

Alternative 2.) Replace the existing 15kV bus with new 4,000 Amp segregated bus. This is the recommended alternative based on the following:

- It's the least cost alternative
- Upgrades bus ratings to be aligned with GCB's and Generators
- Only requires a 6 day outage. This is based on the construction method of installing scaffolding over the existing bus and installing most all of the new horizontal bus by ceiling hangers prior to the outage. Then a shorter six day outage would be required to install the vertical transition boxes at the generator disconnects and B-Phase GSU bus.
- The new bus will has less risk as it will be seismically certified as a packaged system that includes the horizontal and vertical bus sections and associated and hanger and support system.

Timeline for the recommended Alternative 2.):

2020 Q4 Commit to multiyear equipment supply contract – no cost

2021 Q2 Receive Bus A – $200K

Q3 Install Bus A – $400K and place in-service

2022 Q2 Receive Bus B – $200K

Q3 Install Bus A – $400K and place in-service

The project estimate for this equipment and associates labor are reasonable based on the vendor proposals from Eaton and Technibus.

Key Stakeholders are Hydro Managers, Hydro Schedulers, and Plant Operations.

This project is effected by the station service project and it is the driver of when this needs to be done. Due to priorities and projects that are already in the works it is not able to be sequenced until 2023. In order for this to work the station service project will have to be reconfigured and staged so that we can do half of the service and then the other half of the service. In conclusion the project time frame will be changed due to changes in the station service project.

4 APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Cabinet Gorge 15kV Bus Replacement Project and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Glen Farmer Date: 6/28/2019
Print Name: Glen Farmer
Title: Electrical Engineering Manager
Role: Business Case Owner

Signature: Andy Vickers Date: 7/1/2019
Print Name: Andy Vickers
Title: Director GPSS
Role: Business Case Sponsor

Signature: Date:
Print Name:
Title:
Role: Steering/Advisory Committee Review

5 VERSION HISTORY

Version	Implemented By	Revision Date	Approved By	Approval Date	Reason
1.0	Dave Schwall	06/28/19	Glen Farmer	06/28/19	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

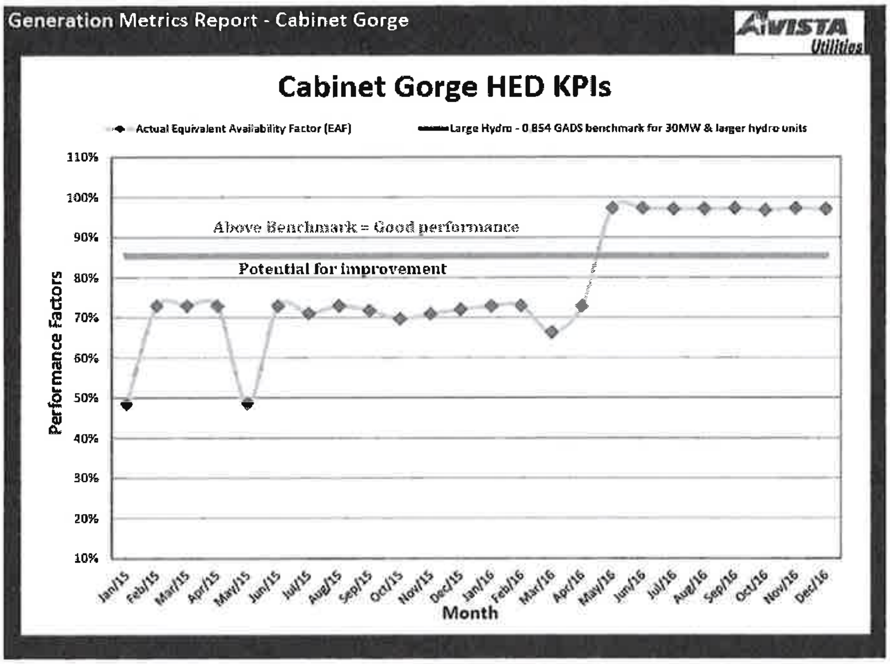
This plant was designed for base load operation. Today, Cabinet Gorge is called on to not only provide load, but to quickly change output in response to the variability of wind generation, to adjust to changing customer loads, and other regulating services needed to balance the system load requirements 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

Cabinet Gorge Automation

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.

Chart 1 – Equivalent Availability Factor



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%

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].

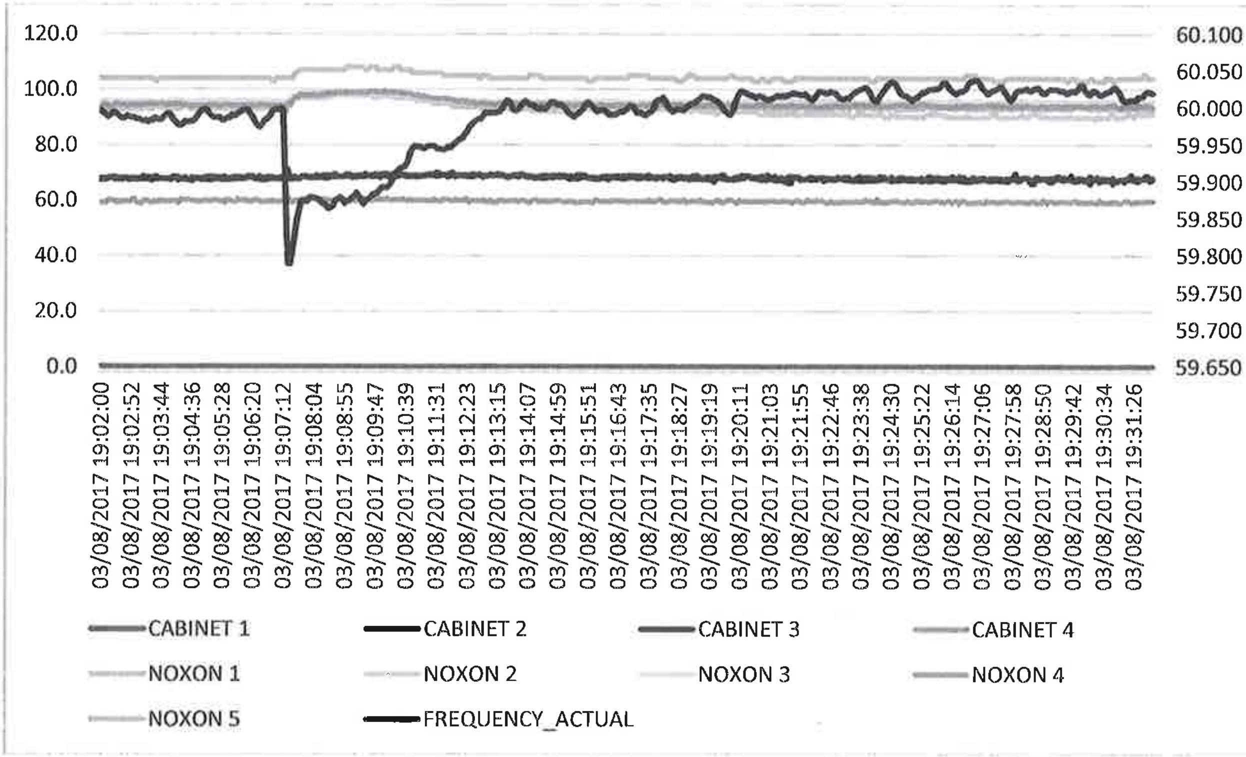
An additional problem with the existing speed controls (governors) is the lack of response in a system frequency event. The graph below shows a significant frequency "excursion" (the dark blue line) and the response of the machines at Noxon Rapids HED to this excursion. Those are the lines that move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

Cabinet Gorge Automation

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

Cabinet Gorge Automation

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: [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

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

Cabinet Gorge Automation

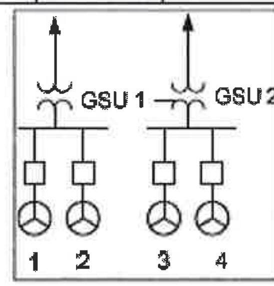
APPENDIX A

AVISTA Utilities

Page 1 of 1

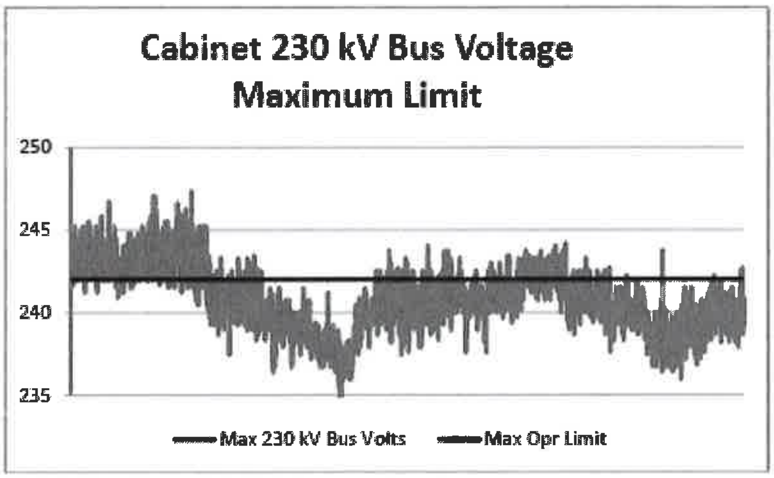
Project:	Cabinet Gorge HED - 230 kV Bus			Date:	03/29/17
Subject:	Bus Operating Voltage Analysis			By:	SEW
				Rev:	1
Proj No.:	09801545	Task:	535000	Ck'd:	

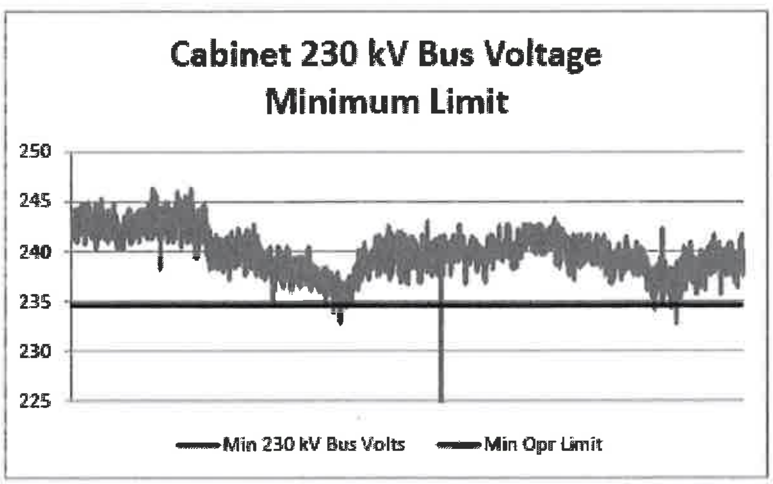
Generating Units Connected
Units 3 and 4



	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
G:\G&P Files\Budget\Capital Budget\2017 Capital Budget\Cabinet Automation\Cabinet Voltage Schedule Report.xlsx

CS2 Single Phase Transformer

EXECUTIVE SUMMARY

Avista has experienced multiple catastrophic GSU transformer failures since the plant's construction in the early 2000's. The purpose of this project is to replace the currently in-service transformer, "T4", which exhibited unacceptably high gassing levels after only being in service a couple of months following the failure of it's twin that failed after approximately nine years of service "T3". Coyote Springs serves Washington and Idaho electric customers. After a detailed financial analysis was performed, the recommended solution is to replace the existing three-phase dual-wound transformer, T4, with three single phase dual-wound transformers. As of the June 2020 (version 3.2) update to this Business Case, the estimated cost is expected to be $21,400,000 which includes replacement of T4 as well as the purchase of a spare unit.

The financial analysis included a calculation of Customer Internal Rate of Return as compared to all possible alternative options. The CIRR of the proposed solution was the highest. Subjectively stated, this project will result in higher reliability and reduced power supply expense. The timeline is critical given the current gassing state of T4. The risk of not approving this business case is the likely failure of T4 with a corresponding outage of 18-24 months.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	*Mike Mecham*	*Initial draft of original business case*	*6.25.19*	*Signed/approved*
2.0	*Thomas Dempsey*	*Updated Budget*	*9.19.19*	
3.0	*Thomas Dempsey*	*Updated Budget*	*12.23.19*	
3.1	*Kara Heatherly*	*Conversion to new format*	*6.20.20*	*Includes budget update*
3.2	*Thomas Dempsey*	*Final Updates to new format*	*7/7/2020*	

GENERAL INFORMATION

Requested Spend Amount	$21,400,000
Requested Spend Time Period	2 years
Requesting Organization/Department	GPSS
Business Case Owner | Sponsor	Thomas Dempsey | Andy Vickers
Sponsor Organization/Department	GPSS
Phase	Execution
Category	Project
Driver	Failed Plant & Operations

CS2 Single Phase Transformer

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Coyote Springs 2 currently uses a single three phase transformer (GSU) configuration for power transformation to the BPA electric grid. Subsequent initial GSU energization in 2002, we have experienced seven GSU failures. In 2018, a spare transformer (T4) was placed in service subsequent the failure of Transformer 3 (T3). After being in service for one month, T4 saw a spike in combustible gases. Gases are now being closely monitored and the transformer is currently limited to 90% capacity.

The Business Problem is that we now have an underperforming transformer that is not at full capacity and which is exhibiting troubling gassing behavior. We consider the risk of failure to be significantly higher than acceptable. We also have no spare at this time- a failure without a spare could lead to an 18 month or longer outage.

The table below is an overview of the historical failures of the 4 three-phase transformers purchased and installed at Coyote Springs 2 since construction:

	Energized date	Failure Date	Comments
Transformer 1 (Alstom - Turkey)	March, 2002	May, 2002	Catastrophic failure - back feed only
Transformer 2 (Alstom - Turkey)		August, 2002	Failed factory impulse testing Retested and passed, Nov 2002
Transformer 2 (Alstom - Turkey)		December, 2002	Shipping damage to core leg - sent to shop for repair
Transformer 2 (Alstom - Turkey)	May, 2003	Jan, 2004	Buchholz alarm, de-energized. Repaired at factory
Transformer 2 (Alstom - Turkey)	August, 2004	March, 2007	Buchholz alarm, de-energized.
Transformer 3 (Siemens - Brazil)	May, 2007	September, 2018	Buchholz alarm - removed from service
Transformer 4 (Siemens - Brazil)	October, 2018	November, 2018	Spike in combustible gas - still in service

1.2 Discuss the major drivers of the business case and the benefits to the customer

Failed Plant Conditions: one of the primary drivers to our selection of this preferred alternative is the likelihood of the risk exposure that remains with an "in kind" three-phase replacement. It is in Avista's best interested to spend these resources on a more reliable solution.

CS2 Single Phase Transformer

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

This work is needed immediately given the condition of the existing transformer and the lack of a reliable spare. If the existing transformer fails now we would expect to see an 18-24 month outage with its associated power supply expense implications. See business problem details in Section 1.1 and additional data and analysis details provided in Section 2.1.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

- **Power Output**- After the project is complete, the operating limit of the plant will be increased to 320 MW- This is an immediate increase and an appropriate objective measure.
- **Gassing Levels**- The new transformers will be outfitted with Serveron Gas Monitoring equipment to ensure that we are not experiencing interal hot spots or arcing that could lead to catastrophic failure.
- **Reliabilty**- We expect the new transformers to provide reliable service immediately and into the future, therefore equipment availability is the third such measure that can be used to determine if the investment has met the stated objectives.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Please see the appendices listed under Section 2.1

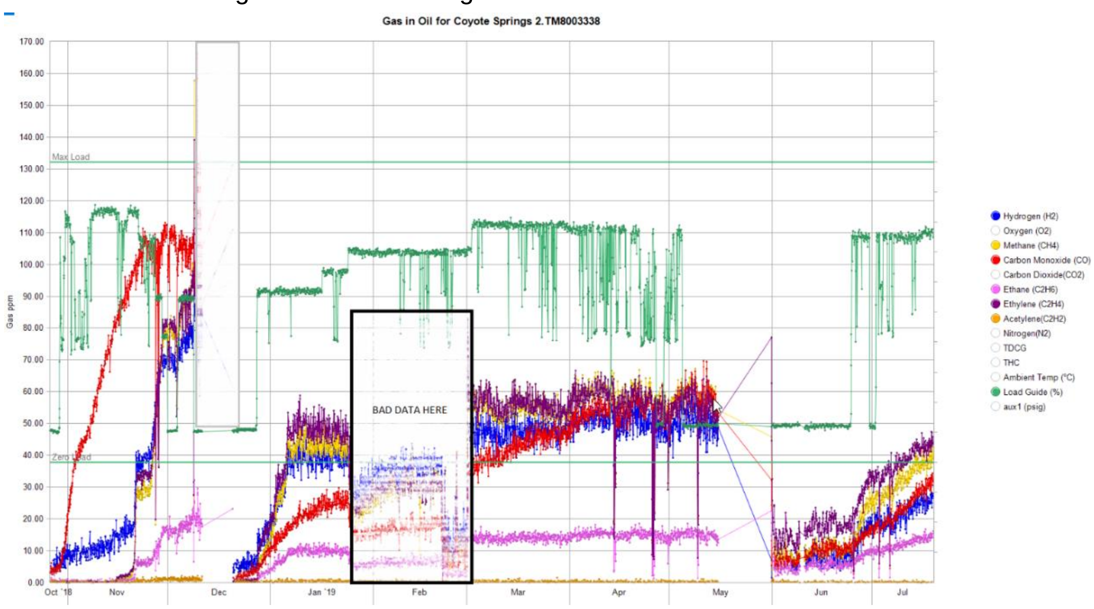
1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

This project provides for replacement of the failed T3 as well as the currently operating but gassing T4. T3 failed catastrophically due to an internal fault. See Figure 1 below that clearly shows internal arcing damage. T4, which is of nearly identical construction as T3, is currently gassing at dangerous levels. If left unchecked, we expect the gasses could reach explosive levels within a two year period. We are carefully monitoring gassing levels to make sure they do not reach these explosive limits during the period of time we are waiting to install the new single phase units. Figure 2 shows the gassing levels currently being seen in T4. In June 2019 we performed a “dialysis” of sorts as a mitigative measure to prevent the dissolved gasses from reaching an explosive level until such time as the transformer can be replaced.

Figure 1- T3 Static Shield Ring Catastrophic Internal Damage

CS2 Single Phase Transformer

Figure 2- T4 Gassing Trend



1.6 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Avista has experienced multiple failures of GSU transformers in service at Coyote Springs despite proper operations and maintenance activities.

- The new transformers will collectively be higher in capacity than the prior transformers at Coyote to provide a higher safety margin and also to allow for technology improvements (which historically have been typical) that allow for higher output at higher efficiency.
- The three phase transformers have proven to be very expensive and difficult to move due to their size and weight. In an email exchange with BPA where Avista asked about use of three

phase transformers in this application, BPA indicated they would not use transformers of this size due to transportation difficulty.

- Changing to a single phase design versus keeping the existing three phase configuration will be challenging- but given the large number of failures Avista believes it is prudent to abandon the existing configuration. To that end, the financial analysis assumptions regarding three phase transformer reliability reflect Avista's experience at Coyote Springs 2.

- The difficulty and enormous complexity of mobilization associated with the three phase solution results in longer duration outages than those associated with individual single phase transformers.

- Avista and its expert consultants determined that manufacturing defects were the likely culprit with respect to the failures of T1 and T2. The failure mechanism for T3 is currently being evaluated. T4 is in service, however it is gassing at dangerous levels. Avista cannot rule out a fundamental application flaw associated with what Siemens and others have described as a somewhat "unusual" configuration. It is possible that this dual low voltage with 500KV high side configuration approach has as yet-to-be determined fundamental flaws. Avista can no longer rule out this possibility given the number of failures we have experienced. PGE, with its single phase transformers is interconnected with the grid at a virtually identical location as unit 2, and they have experienced no failures in 20+ years of operation.

Additional detail and project background can be found in the associate documents:

- Appendix I 20191223 Power Supply Asset Management Consolidated Financial Analysis
- Appendix II David Nichols Engineering Recommendation
- Appendix III Avista-CoyoteSpgs-GSU-Replcmt-Concept-Report_Final_Rpt-w-ATT rev.pdf
- Appendix IV 20191223 Decision Tree Narrative
- Appendix V 20200513 New Financial Analysis of T5 Project.docx

1.7 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

In accordance with the detailed project schedule, annual projected capital expenditures for remaining scope are as identified in the 5-year CPG budget:

- 2020 - $9,900,000
- 2021 - $11,500,000

With respect to O&M reduction, the primary reduction to customer expense is the reduction in power supply expense. The financial analysis includes such risk modified expenses. The financial analysis is included as Appendix I.

CS2 Single Phase Transformer

1.8 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

This project requires internal and external resources for it to be completed successfully.

1.9 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

Note: The following table of results and the associated explanations represent the initial results from the initial study associated with this project. These numbers were based on our best estimates at the time. As we have gotten further into the project, costs have increased due a number of reasons, including increased fire protection requirements and firm bids from suppliers that were higher than initially projected by Avista's Consulting Engineer. The options were subsequently reviewed and Option V remains the best choice for customers. A summary of the new analysis performed may be found in this document: *20200513 New Financial Analysis of T5 Project.docx.*

Option		Capital Cost	NPV of Net Plant Margin	Relative CIRR	Start	Complete
I.	Repair T3, no repair of T4	$6.2 Million	$209.0 Million	4.0%	10/2019	6/2020
II.	Purchase one (1) new 3-phase, no repair of T4	$8.0 Million	$206.5 Million	5.8%	10/2019	12/2020
III.	Purchase one (1) new 3-phase, Repair T3	$13.7 Million	$206.3 Million	5.8%	10/2019	6/2022
IV.	Purchase two (2) new 3-phase units	$13.1 Million	$207.2 Million	6.2%	9/2019	12/2020
V.	***Purchase four (4) single-*****phase transformers (*****includes*** **spare)**	**$15.1 Million**	**$213.9 Million**	**9.4%**	**9/2019**	**6/2021**

Options I- Eliminated due to high power supply risk and relatively lower IRR than the preferred option.

Option II- Eliminated due to high power supply risk and relatively lower IRR than the preferred option.

Option III- Eliminated because Option IV provides superior reliability at lower cost and lacks the opportunity for a double redundant emergency spare. This option also has a relatively lower IRR than the preferred option.

Option IV- Siemens-Austria provided an indicative price for two new 3-phase units at a delivered and commissioned at price of about $9.2 million (Option IV). After other site costs, Avista engineering, and other costs are considered, the price estimate is **$13.1 million**. Furthermore, Avista expects that a choice to begin a new procurement process and a path towards a 3-phase solution would cause significant power supply risk for the summer of 2021. These considerations point further towards Option V as the best solution. Option IV eliminated because even though this option provides the potential for a double redundant emergency spare, it still utilizes the 3-phase dual wound design that has proven unreliable at Coyote Springs in this configuration. This option also has a relatively lower IRR than the preferred option.

CS2 Single Phase Transformer

Option V- Option 5 is the preferred option as it has the highest relative IRR of any of the options. This option uses single phase transformers that are smaller and much easier to transport. This is the same configuration that is used on Unit 1 which have proven highly reliable over time. This option also allows for a double redundant emergency backup using T4 (this would require iso-phase bus reconfiguration and would only be used if single phase lead times dictated the need).

Siemens-Austria and SMIT-Netherlands were the finalists for Option V. David Nichols and Rob Selby from Avista as well as Avista's expert consultant Pierre Feghali visited both factories. While both appeared to be of high quality, Siemens-Austria stood out as a top of class facility with extensive quality control mechanisms in place. It is therefore the factory of choice the transformer supply costs are referenced to.

RECOMMENDATION: Purchase and install four (4) single phase transformers and all supporting equipment (coolers, fans, instrumentation, bushings). Included in the request is all of the design engineering, all equipment modification including containments, fire suppression, electrical protection, isophase bus, and all supporting equipment.

1.10 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

Project planning and design activities began in 2019. In order to minimize outage activities during critical operations windows, the project execution plan will include a two-phased outage during the Spring/Summer of 2020 and 2021.

The 2020 outage will consist of early civil/structural foundation work for the T5A and C locations and T5A, B, and C containment where possible.

The 2021 outage will include all civil/structural activities that require T4 to be out of service and relocated, as well as all other activities (including but not limited to): placement of new transformers, installation of IsoPhase Bus, new deluge system piping, and High Voltage Bus.

Project is expected to be completed and Coyote Springs Unit 2 back online by the end of June 2021.

1.11 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Mission: This project safely, responsibility and affordably improves the level of service we provide to our customers. This project does so by:

- Minimizing our exposure to unnecessary breaks in service
- Avoiding inflated power purchase prices and subsequent increased costs to our customers
- Minimizing the risk of potentially catastrophic failure
- Eliminating ongoing operations safety risks, and
- Eliminating unnecessarily escalating operating costs

Strategic Initiatives: 1. Safe and Reliable Infastructure, 2. Responsible Resources.

1.12 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

A number of alternatives were considered. The recommended course of action represents the highest value of CIRR. See Appendix I and Appendix II.

With respect to investment prudency review; as of version 3.2 of this business case,the project budget was increased to $21.4 million. We conducted a thorough review as well as a new financial analysis to review whether going forward was the best course of action. It was. A complete discussion of this process and its results is provided in Appendix V- *20200513 New Financial Analysis of T5 Project.docx*. A summary table exerpt from that document is provided below:

Options	**Capital Cost $M / Plant Net Market Value $M**	
Options	Original Analysis	Revised Analysis
Option I- Rebuild T3; T4 Spare	6.2/209	Rejected
Option II- New 3Ph, T4 Spare	8/206.5	Rejected
Option III- New 3Ph, Repair T3	13.7/206.3	17.1/202.5
Option IV- Two new 3Ph	13.1/207.2	17.6/202.1
Option V- Single Phase	15.1/213.9	21.4/**206.6**

1.13 Supplemental Information

1.13.1 Identify customers and stakeholders that interface with the business case

There is no customer interface with respect to this project. Key stakeholders include the Avista Power Supply group as well as GPSS.

CS2 Single Phase Transformer

1.13.2 Identify any related Business Cases

This Business Case represents the new 2020 format and thus it replaces the prior approved Business Case titled, “BCJN_CS2 Single Phase Transformer_signed 201912”.

2.1 Steering Committee or Advisory Group Information

Prior to July 2020, executive level oversight of this project was provided on an as-needed basis by Power Supply Management, GPSS Management, and Energy Resources Executive Leadership. Initial project estimates and project execution frameworks were developed by Avista’s consultant engineer and project manager, Black and Veatch.

A formal Steering Committee has been established as of July 2020 and will meet on a quarterly basis over the next year to review project status.

As of March 2020, this project has been assigned an Avista Project Manager responsible for the management and regular reporting of scope, schedule and budget deviations from the current project execution plan.

2.2 Provide and discuss the governance processes and people that will provide oversight

Executive level scope, schedule, & budget oversight is provided by the Steering Committee on a Quarterly basis. Ongoing senior management is provided by the Manager of Thermal Operations. Day to day project oversight is provided by the assigned Project Manager.

2.3 How will decision-making, prioritization, and change requests be documented and monitored

Project decisions will be made at the PM level where appropriate and escalated to the Mananger of Thermal Operations & Maintenance when and if determined to be necessary by the role definitions above. Regular updates will be provided to management by the PM team as project scope, schedule and budget are defined, and throughout the course of the project execution.

The undersigned acknowledge they have reviewed the CS2 Single Phase Transformer Business Case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature: Thomas C Dempsey Date: 7/10/2020

Print Name: Thomas Dempsey

Title: Manager, Thermal Operations

Role: Business Case Owner

Signature: Andy Vickers Date: 7/10/2020

Print Name: Andy Vickers

Title: Director of GPSS

Role: Business Case Sponsor

CS2 Single Phase Transformer

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

Clark Fork License

EXECUTIVE SUMMARY

The ongoing operation of the Clark Fork Project is conditioned by the Clark Fork Settlement Agreement (CFSA) and FERC License No. 2058. The CFSA and License are the result of a multi-year stakeholder engagement and negotiation process, which established the terms of the 45-year license issued to Avista. Imbedded in the license is the requirement to continue to consult agencies, tribes and other stakeholders. In addition, the CFSA and license provide decision-making participation for the settlement signatories, resulting in ongoing negotiations on implementing license terms. The CFSA and license also include a number of funding commitments to help achieve long-term resource goals in the Clark Fork and related watersheds. Some items are relatively predictable each year; many others are dynamic, depending on potential projects, natural resource conditions and evolving resource management goals.

Avista is required to develop an annual implementation plan and report, addressing all Protection, Mitigation and Enhancement (PM&E) measures of the License. Implementation of these measures is intended to address ongoing compliance with Montana and Idaho Clean Water Act requirements, the Endangered Species Act, and state, federal and tribal water quality standards. 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, land use, and related matters.

If the PM&Es and license articles are not implemented and/or funded, Avista would be in breach of an agreement and in violation of our License. There would be risk for administrative orders and penalties, new license requirements, increased mitigation costs, and potential loss of operational flexibility of the Cabinet Gorge and Noxon Rapids Hydro Electric Facilities. Loss of operational flexibility, or of these generation assets, would create substantial new costs, which would be detrimental of all our electric customers. Funding of the Clark Fork License Implementation is essential to remain in compliance with the FERC license and CFSA, which provides Avista the operational flexibility to own and operate the Clark Fork hydroelectric facilities.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Nate Hall*	*Initial draft of original business case*	*6/30/2020*	
1.0	*Nate Hall*	*Completed business case*	*7/23/2020*	
1.1				
2.0				

Clark Fork License

GENERAL INFORMATION

Requested Spend Amount	$5,318,068
Requested Spend Time Period	*1 year*
Requesting Organization/Department	B04/Clark Fork License
Business Case Owner | Sponsor	Nate Hall | Bruce Howard
Sponsor Organization/Department	A04/Environmental Affairs
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

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.

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

These activities fall under the category of Mandatory and Compliance associated with the Clark Fork Settlement Agreement and FERC License. Benefit to our customers and the company is the ability to provide clean, reliable and cost-effective power.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

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 FERC 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.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

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.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Option	Capital Cost	Start	Complete
Capital funding	*$5,318,068*	*01 2021*	*12 2021*
Activity is mandatory – resulting in operational cost overage	*$0*	*01 2021*	*12 2021*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Primary consideration occurred during the multi-year negotiations that led to the CFSA and License. If the PM&Es and license articles are not implemented and/or funded, Avista 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. Loss of operational flexibility, or of these generation assets, would create substantial new costs, which would be detrimental to all our electric customers and the company. Funding of the Clark Fork License Implementation is essential to remain in compliance with the FERC license and CFSA, which provides Avista the operational flexibility to own and operate the hydro-electric facilities.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

As these projects are regulatory obligations, if the capital dollars are not available, they will need to implemented utilizing O&M dollars. Result would be an increase in O&M costs at least equal to the decrease in capital funding available.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

NA

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

If the PM&Es and license articles are not implemented and/or funded, Avista 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.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

This is an ongoing commitment running with the Clark Fork FERC License #2058 and will continue until the License expires in 2046.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Remaining in compliance allows for the continued operation of the Clark Fork HEDs for the benefit of our customers and company. This supports our commitments to collaboration, environmental stewardship, and trustworthiness – all to help deliver clean, renewable energy for our customers.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Prudency is measured by remaining in compliance the FERC License and Clark Fork Settlement Agreement, such that we can continue to operate Noxon and Cabinet dams for the benefit of our customers and company.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

FERC and over 20 other parties, including the States of Idaho and Montana, various federal agencies, five Native American tribes, and numerous Non-Governmental Organizations. In addition, we coordinate with numerous internal stakeholders, in particular within GPSS and Power Supply.

2.8.2 Identify any related Business Cases

Cabinet Gorge Dam Fishway Project has its own business case and supports meeting the overall regulatory requirements of the FERC License and CFSA.

3.1 Steering Committee or Advisory Group Information

3.2 Provide and discuss the governance processes and people that will provide oversight

In addition to the responsible managers, The Clark Fork License Manager, Sr. Director of Environmental Affairs, and

Sr VP Energy Resources & Env Comp Officer, many other internal and external stakeholders provide oversite. Externally, we submit annual work plans and reports to FERC for its review and approval. Many decisions are subject, per the License, to oversite by the Clark Fork Management Committee, consisting of settlement parties. And many elements receive oversite from internal staff in GPSS and Power Supply.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Through normal business case update process; each year of License implementation varies. Each year's budget is established internally at Avista months prior to the actual capital work plan. In addition, resource conditions, permitting and other issues impact work plan implementation each year. As a result, regular "truing up" is required.

The undersigned acknowledge they have reviewed the *Clark Fork License* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	Nate Hall	Date:	7/28/2020
Print Name:	Nate Hall		
Title:	Mgr Clark Fork License		
Role:	Business Case Owner		
Signature:	Bruce F Howard	Date:	7/29/2020
Print Name:	Bruce Howard		
Title:	Sr Dir Environmental Affairs		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Clark Fork License

Template Version: 05/28/2020

Spokane River License Implementation

EXECUTIVE SUMMARY

Non-federal hydroelectric facilities must have a license from the Federal Energy Regulatory Commission (FERC) to operate. Avista's first Spokane River Project License expired in 2007, and after a multi-year process involving hundreds of stakeholders, FERC issued Avista a new 50-year license for the continued operation and maintenance of the Spokane River Project (No. 2545, effective June 18, 2009). This license covers the Post Falls, Upper Falls, Monroe Street, Nine Mile and Long Lake Hydroelectric Developments. 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 the 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 expressed through specific license articles 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 Coeur d'Alene and Spokane Tribes. 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 Water Quality Certification, issued May 8, 2009), the U.S. Forest Service (Federal Power Act 4(e), issued May 4, 2007), and the U.S. Department of Interior on behalf of the Coeur d'Alene Tribe (Federal Power Act 4(e), filed January 27, 2009). The FERC license ensures Avista's ability to operate the Spokane River project on behalf of our electric customers within our service territory for a 50-year license term with an annual cost that varies annually.

Complying with our license is mandatory to continued permission to operate the Spokane River Project and funding the implementation activities is essential to remain in compliance with the FERC license. Specific elements of this program change from year to year, depending on license requirements as well as resource conditions. Ongoing stakeholder engagement, and therefore, negotiation, is also required by the license. As a result, some elements of the license are relatively predictable and static while others are dynamic and evolving.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	*Meghan Lunney*	*Initial draft of original business case*	*7/7/2020*	
1.0	*Meghan Lunney*	*Complete business case*	*7/28/2020*	

Spokane River License Implementation

GENERAL INFORMATION

Requested Spend Amount	$1,011,300
Requested Spend Time Period	*1 year*
Requesting Organization/Department	CO4 – Spokane River License Implementation
Business Case Owner | Sponsor	Meghan Lunney | Bruce Howard
Sponsor Organization/Department	A04 / Environmental Affairs
Phase	Execution
Category	Mandatory
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Non-federal hydroelectric facilities must have a license from the Federal Energy Regulatory Commission (FERC) to operate. Avista's first Spokane River Project License expired in 2007, and after a multi-year process involving hundreds of stakeholders, FERC issued Avista a new 50-year license for the continued operation and maintenance of the Spokane River Project (No. 2545, effective June 18, 2009). This license covers the Post Falls, Upper Falls, Monroe Street, Nine Mile and Long Lake Hydroelectric Developments. This license, based in large part on settlement agreements, defines how Avista shall operate the Spokane River Project and includes several hundred requirements, expressed as license conditions, that we must meet. The license was issued pursuant to the Federal Power Act (FPA) and embodies the 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 expressed through specific license articles 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 Coeur d'Alene and Spokane Tribes, most of which are embodied in the License. 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 Water Quality Certification, issued May 8, 2009), the U.S. Forest Service (Federal Power Act 4(e), issued May 4, 2007), and the U.S. Department of Interior on behalf of the Coeur d'Alene Tribe (Federal Power Act 4(e), filed January 27, 2009). The FERC license ensures Avista's ability to operate the Spokane River project on behalf of our electric customers within our service territory for a 50-year license term. The capital costs of implementing the License varies each year, depending on specific requirements and opportunities to accomplish projects.

Spokane River License Implementation

1.2 Discuss the major drivers of the business case *(Customer Requested, Customer Service Quality & Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition, or Failed Plant & Operations)* and the benefits to the customer

Complying with our license is mandatory for continued permission to operate the Spokane River Project. Funding implementation activities is essential to remain in compliance with the FERC license. Specific elements of this program change from year to year, depending on license requirements as well as resource conditions. Ongoing stakeholder engagement, and therefore, negotiation, is also required by the license. As a result, some elements of the license are relatively predictable and static while others are dynamic and evolving.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred

Complying with our license is mandatory to continued permission to operate the Spokane River Project and funding the implementation activities is essential to remain in compliance with the FERC license. Ultimately, FERC has the authority to issue orders and penalties, or in the extreme, 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. In addition, Avista would suffer reputational costs for not meeting our commitments.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

The Spokane River License team engages with the regulatory agencies and stakeholders in annual, five-year, and ten-year planning to implement the license and settlement agreement conditions. Implementation measures for each of the natural resource conditions have specific success criteria identified. This data along with key accomplishments are reported/documented as part of the license conditions, along with agency/stakeholder approvals. We, as well as FERC, maintain a complete record of our stakeholder consultation, work and project planning, and reported results.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Federal Energy Regulatory Commission (FERC). 2009. Order Issuing New License and Approving Annual Charges For Use Of Reservation Lands. Issued June 18.

Avista. 2005. Spokane River Hydroelectric Project, FERC No. 2545, Final Application for New License Major Project – Existing Dam. July 2005.

Avista. 2005. Post Falls Hydroelectric Project, Currently Part of Project No. 2545, Final Application for New License Major Project – Existing Dam. July 2005.

Spokane River License Implementation

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

NA.

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 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.

Option	Capital Cost	Start	Complete
Capital Funding	*$1,011,300*	*01 2021*	*12 2021*
Activity is mandatory resulting in operational cost overage	*$0*	*01 2021*	*12 2021*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Implementation measures conducted under this capital request are based upon regular meetings engaging with regulatory agencies and external and internal stakeholders during annual, five-year, and ten-year planning meetings. Implementation measures for each of the natural resource conditions have specific success criteria identified. This data along with key accomplishments are reported/documented as part of the license conditions, along with agency/stakeholder approvals. At every opportunity during project planning cost sharing options and opportunities are fully explored to ensure Avista’s fiduciary duty to its customers is upheld.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?). Include any known or estimated reductions to O&M as a result of this investment.

The requested capital costs will be implemented in accordance with the schedules, milestones and benchmarks identified in the annual planning process as identified and committed to within annual, five-year and ten-year workplans. The work is completed in collaboration with internal and external stakeholders.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

The Spokane River implementation activities are coordinated across many internal departments to ensure other business functions/processes are not impacted. Collaboration is an essential component of the work and successful implementation is dependent upon input from other internal departments. GPSS and Power Supply, in particular, depend on the successful implementation of our License activities.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

There are no practicable alternatives to meeting 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.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

Implementing the license activities will take place over the course of the year extending from January through December. Transfers will happen throughout the course of the year.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

Implementing the required Spokane River license conditions during 2020 is required by the FERC license in order to operate the Spokane River Hydroelectric Project. This ensures a reliable energy supply for our customers. The License is the result of seven years of community-based collaboration, and implementation also reflects ongoing collaboration with key stakeholders. Additionally, these implementation measures showcase Avista's ongoing commitment to environmental stewardship which benefits our customers, the company and the communities we serve.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

The requested capital costs will be implemented in accordance with the schedules, milestones and benchmarks identified in the annual planning process as identified and committed to within annual, five-year and ten-year workplans. The work is completed in collaboration with internal and external stakeholders. At every opportunity during project planning cost sharing options and opportunities are fully explored to ensure Avista's fiduciary duty to its customers is upheld. Project costs are reviewed monthly, if not weekly, and managed tightly by each Spokane River resource lead, budget analyst and the Spokane River License Manager.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The majority of our external agency stakeholders that interface with this business case include the Idaho Department of Environmental Quality, Idaho Department of Fish and Game, Idaho State Historic Preservation Office, Idaho Department of Lands, Washington Department of Ecology, Washington Department of Fish and Wildlife, Washington State Historic Preservation Office, Washington Department of Natural Resources, U.S. Forest Service, U.S. Fish and Wildlife Service, U.S. Department of Interior, Coeur d'Alene Tribe, and Spokane Tribe. Additional external stakeholders including conservation districts, non-profits, and local educational institutions, as well as a number on non-governmental environmental organizations.

Major internal stakeholders include GPSS, Power Supply, External Communications, etc.

2.8.2 Identify any related Business Cases

NA.

3.1 Steering Committee or Advisory Group Information

Prior to receiving the license, 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. Now that the license has been issued for a term of 50-years, governance is multi-faceted and includes the Spokane River License team engaging with regulatory agencies, stakeholders, and many internal departments including GPSS, Power Supply, and External Communications to ensure the appropriate governance is applied per natural resource implementation condition.

3.2 Provide and discuss the governance processes and people that will provide oversight

Now that the license has been issued for a term of 50-years, governance is multi-faceted and includes the Spokane River License team engaging with regulatory agencies, external and internal stakeholders in annual, five-year, and ten-year planning to implement the license and settlement agreement conditions. Implementation measures for each of the natural resource conditions have specific success criteria identified. This data along with key accomplishments are reported/documented as part of the license conditions, along with agency/stakeholder approvals. Internal governance can include steering committees for specific major projects, as well as the organizational hierarchy within which the Spokane River team operates. Work coordination occurs through multi-departmental meetings and work planning.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Decision-making, prioritization, and change requests will be documented and monitored by each natural resource lead on the Spokane River Team and reviewed by the Spokane River License Manager and others, depending on financial authority. Budget is tracked and reviewed on a monthly, if not weekly basis, and a change request form will be completed should additional, or less, funding be needed to implement the license conditions under this business case. Spending and invoices are reviewed and tracked at each level within the organization per budget approval authorities.

The undersigned acknowledge they have reviewed the *Spokane River License Implementation* and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Spokane River License Implementation

Signature:	Meghan Lunney	Date:	7/28/2020
Print Name:	Meghan Lunney		
Title:	Mgr Spokane River License		
Role:	Business Case Owner		

Signature:	Bruce F Howard	Date:	7/29/2020
Print Name:	Bruce Howard		
Title:	Sr Dir Environmental Affairs		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

GPSS_Base Load Thermal Program

EXECUTIVE SUMMARY

Avista's Base Load Thermal plants include **Coyote Springs 2** and **Kettle Falls Generating Station**. These two base loaded plants have uniquely different operational flexibility to best serve Avista's customers energy demands. Coyote Springs 2 is a natural gas fired combined cycle unit which generates 300 MW's. It is equipped with automation to adjustment unit output to match changing system loads and other types of services necessary to provide a stable electric grid. Kettle Falls is a base loaded renewable resource with the ability to store energy for long periods of time to optimize energy markets to best serve Avista Renewable needs.

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. These projects are also reviewed in an owner committee setting during meetings at the plant that take place on a monthly basis. Kettle Falls Generation Station projects are identified and prioritized through the plant Budget Committee. Both plants utilize the GPSS ranking matrix system to evaluate the projects.

The operational availability for these plants is paramount. The service code for this program is Electric Direct and the jurisdiction for the program is Allocated North serving our electric customers in Washington and Idaho

Individual projects which are identified are then 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.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Greg Wiggins	Initial draft of original business case	7/8/2020	

GPSS_Base Load Thermal Program

GENERAL INFORMATION

Requested Spend Amount	$14,880,000
Requested Spend Time Period	*5 years*
Requesting Organization/Department	C06, K07 / GPSS
Business Case Owner | Sponsor	Thomas Dempsey | Andy Vickers
Sponsor Organization/Department	A07 / GPSS
Phase	Initiation
Category	Program
Driver	Asset Condition / Failed Equipment

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

This program is important in providing funding to support the replacement of critical assets and systems for the reliable operations of these facilities. These two plants provide full load output during peak power demands when other resources are limited. This program allows for smaller strategic asset management and planning while allowing for emergent funding of failed plant assets. It is difficult to predict failures and unscheduled problems of operating thermal generating facilities this allows for quick access to funding when breakdown occur.

1.2 Discuss the major drivers of the business case

The major drivers for this business case are Asset Condition and Failed Plant. This program provides funding for small capital projects that are required to support the safe and reliable operation of these thermal facilities. The reliable operations and generating capacity of these plants maximize value for Avista and our customers.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred.

Critical asset condition and failed equipment jeopardize the safe and reliable operation of these generating facilities. If problems are not resolved in a timely manner, the plant and plant personnel could be at risk and failed or unavailable critical assets and systems will limit plant flexibility and availability. This could have a substantial cost impact to Avista and our customers.

Without this funding source it will be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This will jeopardize plant availability and greatly impact the value to customers and the stability of the grid.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Plant reliability and availability is measured, as well as the frequency and nature of forced outages. These metrics will contribute to prioritizing the projects in this program. Historically, this program has funded multiple projects per year which contributed to unit availability. Both plants have seen increased capacity and output over the years.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The historical drivers of the projects selected to be funded by the program are a mix of Asset Condition and Failed Plant. About 75% of the annual budget is planned due to Asset Condition with 25% reserved for Failed Plant that arise during the year. Many of these projects are small in scope and budget.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Being a Program, this review will be performed on a project by project basis. This decision will be made by the program Steering Committee.

Using funds from the Base Load Thermal Program, spend $2,790,000 per year in 2021-2022; spend $3,100,000 per year in 2023-2025.

Option	Capital Cost	Start	Complete
Base Load Thermal Program	*14,880,000*	*01/2021*	*12/2025*
Individual Capital Projects	*14,880,000*	*01/2021*	*12/2025*

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Maximo is the system of record for recording failed plant assets. Work orders are used to show trends in increased maintenance or complete failures. Some projects are driven by asset age and are no longer supported by the OEM.

GPSS_Base Load Thermal Program

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

If capital funds were not available for the projects in this program, reliability of the plant would decrease and more O&M would need to be performed to repair aging equipment instead of replacement. This would be an unacceptable and substantial increase in the O&M expenditures.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

These projects vary in size and support needed from the Department and key stakeholders. The larger projects require formal project management with a broader stakeholder team. Medium to small projects can be implemented by a project engineer or project coordinator and many cases can be handled by contractors managed by the regional personnel. All of these projects are prioritized and coordinated by the broader support team.

2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

One alternative would be to create business cases using the business case template and process for each of these small projects. There are typically 30-50 projects a year funded by the program between the two plants. This would overload the Capital Budget Process with small to medium projects whose governance can be effectively handled by the Thermal Organization. These projects are specific to these plants and the leadership in Thermal Operations understand the best the nature and context of these projects.

These projects are somewhat unpredictable. It would be difficult to forecast unforeseen events such as equipment failures and identify critical asset condition that could effectively be put in the annual capital plan.

Another alternative would be to attempt to repair this equipment instead of replacing critical assets at the end of their lifecycle. This will be expensive and older equipment will become more and more unreliable until it becomes obsolete. Operating in a run-to-failure mode is proven to be an unsuccessful approach and subjects Avista and its customers to risk.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer.

The projects in this program for Coyote Springs 2 and Kettle Falls typically take place during the annual outages, which are typically in May-June of each year. There are projects that are completed throughout the year without requiring a unit outage by utilizing standby equipment.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The purpose of this program is to provide funding for small to medium size projects with the objective of keeping our thermal plants reliable and available. By doing this we support our mission of improving our customer's lives through innovative energy solutions which includes thermal generation. Executing the projects funded by the program, we insure that Thermal Facilities are performing at a high level and serving our customers with affordable and reliable energy.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Historically the two plant have been able to work within a 3 million annual budget allocation. Some years one plant is in need of more and adjustments are made with the other plant to accommodate the need. Since the inception of the Base Load Program funding Coyote Springs and Kettle Falls Generation Station has been able to work well in making continued improvement to the plant assets through small incremental steps. Each individual project is reviewed by the Plant Manager the approved by the GPSS Thermal Operations and Maintenance Manager prior to beginning work.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The list of primary customers and stakeholders includes: GPSS, Environmental Resources, Power Supply, Systems Operations, ET, and electric customers in Washington and Idaho

2.8.2 Identify any related Business Cases

None.

GPSS_Base Load Thermal Program

3.1 Steering Committee or Advisory Group Information

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

The plant Budget Committee utilizes GPSS Department Project Ranking 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.

For Coyote Springs 2, 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 projects are also reviewed in an owner committee setting during meetings at the plant that take place on a monthly basis.

3.2 Provide and discuss the governance processes and people that will provide oversight

Projects are proposed through various organizations in Generation Production and Substation Support (GPSS) and through key stakeholder such as Environmental Resources, Safety and Security. The projects are vetted by the Advisory Group. With the assistance of Operations, Construction and Maintenance and Engineering, projects are evaluated to determine available options, confirm prudency, and bring potential solutions forward.

This same vetting process is followed for emergency projects and may include other key stakeholders. Over the course of the year, the program is actively managed by the Plant Managers, with the assistance of their Advisory Groups. This includes monthly analysis of cost and project progress and reporting of expected spend.

3.3 Provide and discuss the governance processes and people that will provide oversight

Projects are proposed through various organizations in Generation Production and Substation Support (GPSS) and through key stakeholder such as Environmental Resources, and Safety and Security. The projects are vetted by the Advisory Group. With the assistance of Operations, Construction and Maintenance and Engineering, projects are evaluated to determine available options, confirm prudency, and bring potential solutions forward.

This same vetting process is followed for emergency projects and may include other key stakeholders. Over the course of the year, the program is actively managed by the Plant Managers, with the assistance of their Advisory Groups. This includes monthly analysis of cost and project progress and reporting of expected spend.

3.4 How will decision-making, prioritization, and change requests be documented and monitored

Each project request will be evaluated by the Advisory Group which will include the scope, cost and risk associated with the project. The project will be evaluated based on the impact or potential impact of the operation of the Thermal plants. The selection and approval of the project will be based on the experience and consensus of the Advisory Group.

Depending on the size of the project, a Project Manager or Project Coordinator may be assigned. They will follow the project management process for reporting and identifying and executing change orders. Smaller projects will have a point of contact and financials will be reviewed on a monthly basis by the Advisory Group.

The undersigned acknowledge they have reviewed the *Base Load Thermal Program Business Case* and agree with the approach it presents. Significant

GPSS_Base Load Thermal Program

changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:		Date:	7/10/2020
Print Name:	Thomas Dempsey		
Title:	Manager of Thermal Ops & Maint		
Role:	Business Case Owner		

Signature:		Date:	7/10/2020
Print Name:	Andy Vickers		
Title:	Director of GPSS		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

Regulating Hydro

EXECUTIVE SUMMARY

Avista's regulating hydro plants are unique in that they have storage available in their reservoirs. This enables these plants to have operational flexibility and 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 and include Noxon Rapids and Cabinet Gorge on the Clark Fork River in Montana and Idaho and Long Lake and Little Falls on the Spokane River.

The operational availability for these generating units in these plants is paramount. The service code for this program is Electric Direct and the jurisdiction for the program is Allocated North serving our electric customers in Washington and Idaho. The purpose of this program is to fund smaller capital expenditures and upgrades that are required to maintain safe and reliable operation. 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 (BES).

Projects completed under this program include replacement of failed equipment and small capital upgrades to plant facilities. The business drivers for the projects in this program is a combination of Asset Condition, Failed (or Failing) Plant, and addressing operational deficiencies. Most of these projects are short in duration, typically well within the budget year, and many are reactionary to plant operational support issues. Without this funding source it will be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This will jeopardize plant availability and greatly impact the value to customers and the stability of the grid.

Due to the age of the facilities more and more critical assets, support systems and equipment are reaching the end of their useful life. This program is critical in continuing to support asset management program lifecycle replacement schedules.

The annual cost of this program is variable and depends on discovery of unfavorable asset condition and the unpredictability of equipment failures.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Bob Weisbeck	Initial draft of original business case	6/29/20	
1.0	Bob Weisbeck	Final signed business case	7/2/20	

Regulating Hydro

GENERAL INFORMATION

Requested Spend Amount	$16,800,000
Requested Spend Time Period	5 years
Requesting Organization/Department	L07, D07, I07 / GPSS
Business Case Owner | Sponsor	Bob Weisbeck | Andy Vickers
Sponsor Organization/Department	A07 / GPSS
Phase	Initiation
Category	Program
Driver	Asset Condition / Failed Equipment

1. BUSINESS PROBLEM

1.1 What is the current or potential problem that is being addressed?

Due to the age and continuous use of the regulating hydro facilities, more and more critical assets, support systems and equipment are reaching the end of their useful life. In addition, it is difficult to predict failures and unscheduled problems of operating hydroelectric generating facilities. This program is critical in providing funding to support the replacement of critical assets and systems that support the reliable operations of these critical facilities.

1.2 Discuss the major drivers of the business case

The major drivers for this business case are Asset Condition and Failed Plant. This program provides funding for small capital projects that are required to support the safe and reliable operation of these hydro facilities. The flexible operations and generating capacity of these plants, maximize value for Avista and our customers.

1.3 Identify why this work is needed now and what risks there are if not approved or is deferred.

Critical asset condition and failed equipment jeopardize the safe and reliable operation of these generating facilities. If problems are not resolved in a timely manner, the plant and plant personnel could be at risk and failed or unavailable critical assets and systems will limit plant flexibility and availability. This could have a substantial cost impact to Avista and our customers.

Without this funding source it will be difficult to resolve relatively small projects concerning failed equipment and asset condition in a timely manner. This will jeopardize plant availability and greatly impact the value to customers and the stability of the grid.

1.4 Identify any measures that can be used to determine whether the investment would successfully deliver on the objectives and address the need listed above.

Plant reliability and availability is measured as well as the frequency and nature of forced outages. These metrics will contribute to prioritizing the projects in this program. Historically, this program has funded multiple projects per year which contributed to high unit availability.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The historical drivers of the projects selected to be funded by the program are a mix of Asset Condition, approximately 87% and Failed Plant, approximately 13%. Projects are typically completed in the calendar year. The work is primarily performed in the 3rd and 4th quarters of the year when outage in the Hydro Plants are scheduled, typically after run off in the rivers has subsided.

1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

Being a program, this review will be performed on a project by project basis. This decision will be made by the program Advisory Group.

Option	Capital Cost	Start	Complete
Regulating Hydro Program	$16,800,000	*01/2021*	*12/2025*
Individual Capital Projects	$16,800,000	*01/2021*	*12/2025*
Perform O&M maintenance	0		

Regulating Hydro

2.1 Describe what metrics, data, analysis or information was considered when preparing this capital request.

Review of the program budget over the period of the last six years has revealed a realistic annual budget is $3.5 Million.

The drivers of the projects selected to be funded by this program are mix Asset Condition (approximately 87%) and Failed Plant (13%). Resolving issues encountered in operating these plants in a timely manner benefits the customers with providing safe, reliable, low cost power which supports the needs of Bulk Electric System and provides value to Avista and our customers.

2.2 Discuss how the requested capital cost amount will be spent in the current year (or future years if a multi-year or ongoing initiative). (i.e. what are the expected functions, processes or deliverables that will result from the capital spend?)**. Include any known or estimated reductions to O&M as a result of this investment.**

The annual budget program, based on review of the past six years, is approximately $3.5 million. In order support the budget constraints of the department, this amount has been reduced by 10% for 2021 and 2022. Projects with lower risk will be delayed through this period. The projects in this program typically take place during the outages which are in the summer and fall of each year. Most of the capital is deployed in the 3rd and 4th quarter of each year.

If capital funds were not available for the projects in this program, reliability of the plant would decrease, and more O&M would need to be performed to repair aging equipment instead of replacement. This would be an unacceptable and substantial increase in the O&M expenditures.

2.3 Outline any business functions and processes that may be impacted (and how) by the business case for it to be successfully implemented.

These projects vary in size and support needed based on the requests from the department and from key stakeholders. The larger projects require formal project management with a broader stakeholder team. Medium to small projects can be implemented by a project engineer or project coordinator and many cases can be handled by contractors managed by the regional personnel. All these projects are prioritized and coordinated by the broader support team.

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2.4 Discuss the alternatives that were considered and any tangible risks and mitigation strategies for each alternative.

One alternative would be to create business cases using the business case template and process for each of these small projects. There are typically 40-50 projects a year funded by the program. This would overload the Capital Budget Process with small to medium projects whose governance can be effectively handled by the hydro organization. These projects are specific to these plants and the leadership in hydro operations understand the best the nature and context of these projects.

These projects are somewhat unpredictable. It would be difficult to forecast unforeseen events such as equipment failures and identify critical asset condition that could effectively be put in the annual capital plan.

Another alternative would be to attempt to repair this equipment instead of replacing critical assets at the end of their lifecycle. This will be unacceptably expensive and older equipment will become more and more unreliable until it becomes obsolete. Operating in a run-to-failure mode is proven to be an unsuccessful approach and subjects Avista and its customers to unacceptable risk.

2.5 Include a timeline of when this work will be started and completed. Describe when the investments become used and useful to the customer. spend, and transfers to plant by year.

The projects in this program typically take place during the outages for the Hydro Plants which are typically in the summer and fall of each year. Some projects may have the ability to be performed in the first two quarters of the year but most of the capital is deployed in the 3rd and 4th quarter of each year. Work performed in and around the dams that require outages typically is safer and more cost effective after run off has occurred in the rivers.

2.6 Discuss how the proposed investment aligns with strategic vision, goals, objectives and mission statement of the organization.

The purpose of this program is to provide funding for small to medium size projects with the objective of keeping our hydroelectric plants reliable and available. These plants affordably support the power needs of our company and our customers. By taking care of these plants we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By executing the projects funded by the program, we ensure that hydro facilities are performing at a high level and serving our customers with affordable and reliable energy.

2.7 Include why the requested amount above is considered a prudent investment, providing or attaching any supporting documentation. In addition, please explain how the investment prudency will be reviewed and re-evaluated throughout the project

Review of the program budget has revealed that a realistic annual budget is $3.5 Million. In order to support the capital budget goals of the GPSS department, this budget was reduced in the short term for 2021 and 2022 by 10% per year. Projects with lower risk will be delayed through this period.

The drivers of the projects selected to be funded by this program are mix Asset Condition (approximately 87%) and Failed Plant (13%). Resolving issues encountered in operating these plants in a timely manner benefits the customers with providing safe, reliable, low cost power which supports the needs of Bulk Electric System and provides value to Avista and our customers.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The list of primary customers and stakeholders includes: GPSS, Environmental Resources, Power Supply, Systems Operations, ET, and electric customers in Washington and Idaho.

2.8.2 Identify any related Business Cases

3.1 Advisory Group Information

The Advisory Group for this program consists of the four regional Hydro Managers and the Sr Manager of Hydro Operations and Maintenance.

3.2 Provide and discuss the governance processes and people that will provide oversight

Projects are proposed through various organizations in Generation Production and Substation Support (GPSS) and through key stakeholder such as Environmental Resources, Dam Safety, and Safety and Security. The projects are vetted by the Hydro Advisory Group. With the assistance of Operations, Construction and Maintenance and Engineering, projects are evaluated to determine available options, confirm prudency, and bring potential solutions forward.

This same vetting process is followed for emergency projects and may include other key stakeholders. Over the course of the year, the program is actively managed by the Sr. Manager of Hydro Operations, with the assistance of the Advisory Group. This includes monthly analysis of cost and project progress and reporting of expected spend.

3.3 How will decision-making, prioritization, and change requests be documented and monitored

Each project request will be evaluated by the Advisory Group which will include the scope, cost and risk associated with the project. The project will be evaluated based on the impact or potential impact of the operation of the Regulating Hydro plants. The selection and approval of the project will be based on the experience and consensus of the Advisory Group.

Depending on the size of the project, a Project Manager or Project Coordinator may be assigned. In this case, the project management process will be followed for reporting and identifying and executing change orders. Smaller projects will have a point of contact and financials will be review on a monthly basis by the Advisory Group.

The undersigned acknowledge they have reviewed the Regulating Hydro Program business case and agree with the approach it presents. Significant changes to this

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will be coordinated with and approved by the undersigned or their designated representatives.

Signature:	R. S. Weisbeck	Date:	7-2-2020
Print Name:	Bob Weisbeck		
Title:	Manager, Hydro Ops and Maint		
Role:	Business Case Owner		

Signature:	ANdrew Vickers	Date:	7/2/2020
Print Name:	Andrew Vickers		
Title:	Director GPSS		
Role:	Business Case Sponsor		

Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Template Version: 05/28/2020

Index for Business Case Justification Narratives Related to 2018-2022 Colstrip Capital Additions		
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Colstrip 3&4 Capital

1 GENERAL INFORMATION

Requested Spend Amount	$12,500,000
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 although individual projects can be cancelled or postponed if a sufficient majority of the owners agree.

Generally, by the subsequent November meeting, the business plan is approved in accordance with the Ownership and Operation Agreement for units 3&4 that six companies are party to. The amount requested in this Business case is generally an estimate taken from the prior year's forecast. As a result, the final approved Colstrip capital budget may not exactly match the amount highlighted in this Business Case.

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)	$12.5 M		N/A	

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

- *The operator (Talen) 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:	Thos. C. Dempsey	Date:	6/27/2019
Print Name:	Thomas Dempsey		
Title:	Manager Thermal Ops & Maint		
Role:	Business Case Owner		

Signature:	[signature]	Date:	6/27/19
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	04/17/2017	Steve Wenke	04/17/2017	Initial version
2.0	Thomas Dempsey	06/27/2019	Andy Vickers	06/27/2019	2020 Update

Template Version: 06/27/2019