

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-22 _____

EXH. JRT-4

JASON R. THACKSTON

REPRESENTING AVISTA CORPORATION

Capital Additions for 2021

Project #	Business Case	2021 TTP (System)	Exh. JRT-4 Page #
Generation			
1	Automation Replacement	\$ 632,112	3
2	Base Load Hydro	639,601	10
3	Base Load Thermal Program	2,501,333	18
4	Cabinet Gorge 15 kV Bus Replacement	394,671	26
5	Cabinet Gorge Dam Fishway	126,550	30
6	Cabinet Gorge Unit 3 Protection & Control Upgrade	3,073,449	39
7	Cabinet Gorge Unit 4 Protection & Control Upgrade	2,714,355	45
8	Clark Fork Settlement Agreement	5,477,022	51
9	Coyote Springs LTSA	15,898,972	57
10	CS2 Single Phase Transformer	17,052,971	64
11	Generation DC Supplied System Update	6,864	74
12	HMI Control Software	3,055,633	81
13	Hydro Safety Minor Blanket	49,317	90
14	Little Falls Plant Upgrade	1,680,999	95
15	Long Lake Plant Upgrade	2,264,782	102
16	Peaking Generation Business Case	598,839	113
17	Post Falls Landing and Crane Pad Development	3,508,167	121
18	Regulating Hydro	3,367,438	127
19	Spokane River License Implementation	904,651	135
20	Strategic Initiatives	3,373,971	142
21	Use Permits	27,142	151
22	WSDOT Franchises	20,525	157
Total Generation		\$ 67,369,363	
Exh. JRT-1T Total 2021 Capital Additions		\$ 67,369,363	

* = single Q&A - describing the project & refer to the business case in Testimony

** = quick sentence; for this project, please see 2022-2024 TTP section below

Provisional Capital Additions for 2022-2024 by Plant Group
Thackston

WA GRC Plant Group	Project #	Business Case	2022 TTP (System)	2023 TTP (System)	2024 TTP (System)	Exh. JRT-4 Page #	
Large Distinct Projects	23	Boulder Park Generator Replacement	\$ -	\$ -	\$ 999,998	163	
	24	Cabinet Gorge HVAC Replacement	-	1,500,000	-	169	
	25	Cabinet Gorge Station Service	7,761,859	5,152,936	-	178	
	26	Cabinet Gorge Stop Log Replacement	-	1,200,000	-	184	
	27	Cabinet Gorge Unit 4 Protection & Control Upgrade	750,000	-	-	45	
	28	Cabinet Gorge Unwatering Pumps	395,000	395,016	-	192	
	29	Generation DC Supplied System Update	550,001	550,001	400,000	74	
	30	Generation Masonry Building Rehabilitation	493,993	493,995	493,990	198	
	31	Generation Protection Upgrades	-	-	587,500	205	
	32	KF_Fuel Yard Equipment Replacement	-	30,367,127	-	214	
	33	Long Lake Plant Upgrade	-	-	19,541,000	102	
	34	Monroe Street Abandoned Penstock Stabilization	-	899,992	-	226	
	35	Nine Mile HED Battery Building	800,001	-	-	234	
	36	Nine Mile Powerhouse Crane Rehab	1,699,988	-	-	243	
	37	Nine Mile Units 3 & 4 Control Upgrade	-	2,000,000	1,999,999	251	
	38	Noxon Rapids HVAC	-	-	1,250,002	259	
	39	Peaking Generation Business Case	445,001	458,000	450,000	113	
	40	Post Falls North Channel Spillway Rehabilitation	-	-	18,499,999	266	
	41	Upper Falls Trash Rake Replacement	-	1,500,000	-	275	
	Total Large Distinct Projects			\$ 12,895,843	\$ 44,517,067	\$ 44,222,488	
	Mandatory & Compliance	42	Cabinet Gorge Dam Fishway	\$ 63,475,101	\$ 235,000	\$ -	30
43		Clark Fork Settlement Agreement	4,839,609	5,622,720	3,877,380	51	
44		Spokane River License Implementation	629,226	535,000	492,301	135	
45		Strategic Initiatives	225,225	-	-	142	
46		Use Permits	150,012	150,012	150,012	151	
47		WSDOT Franchises	99,996	99,996	99,996	157	
Total Mandatory & Compliance			\$ 69,419,169	\$ 6,642,728	\$ 4,619,689		
Programs	48	Automation Replacement	\$ 349,999	\$ 349,999	\$ 600,000	3	
	49	Base Load Hydro	958,925	963,504	963,504	10	
	50	Base Load Thermal Program	2,484,254	2,693,105	2,623,988	18	
	51	Regulating Hydro	2,947,845	2,961,000	2,961,000	127	
Total Programs			\$ 6,741,023	\$ 6,967,608	\$ 7,148,492		
Short-Lived Assets	52	HMI Control Software	\$ 3,500,000	\$ 2,550,000	\$ 1,550,000	81	
Total Short-Lived Assets			\$ 3,500,000	\$ 2,550,000	\$ 1,550,000		
Exh. JRT-1T Total 2022-2024 Provisional Capital Additions			\$ 92,556,035	\$ 60,677,403	\$ 57,540,669		

Automation Replacement

EXECUTIVE SUMMARY

The purpose of this program is to replace aging controllers and meters. Controllers are used to automate, control and monitor Avista's generating facilities. Each generating unit has a meter that measures MWh and MVARh. The controllers and meters of concern are aging and introducing an increase in hardware, software, and communication failures that limit Avista's ability to operate generating facilities reliably. The recommended solution is to replace all aging controllers and meters proactively on a schedule that takes into account resources and outage availability. The project cost to replace an outdated meter costs about \$40,000 and a controller costs about \$300,000-\$500,000 depending on the complexity. Proactively replacing these devices benefits customers by reducing unexpected plant outages that require emergency repair with like equipment. A planned approach allows engineers and technicians to update logic programs more effectively and replace hardware with current standards.

When this program was proposed in 2017 a 10-year plan was provided that captured the various controllers through Avista's generating facilities that need to be upgraded. This program funded the replacement of five outdated controllers over the last 3 years. These five controllers are in addition to 10 other controllers that have been replaced as part of other large capital projects. The program allows the overdue replacements of controllers and meters to happen at quicker pace to improve reliability and also support the HMI program and EIM program. The 10-year plan for this program is on track to replace remaining controllers that are outdated over the next seven years. The majority of meters will be upgraded by 2022 in preparation for the EIM. The risk of not continuing this business case slows progress toward replacing aging and outdated controllers and meters that could result in an unplanned outage or a cyber security issue.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	<i>Kristina Newhouse</i>	<i>Initial draft to convert to new template</i>	<i>7/2/2020</i>	<i>Existing Business Case. Executive summary only.</i>
2.0	<i>Kristina Newhouse</i>	<i>Complete remaining template</i>	<i>7/31/2020</i>	<i>Remaining sections 1, 2, & 3.</i>

Automation Replacement

GENERAL INFORMATION

Requested Spend Amount	\$650,000
Requested Spend Time Period	<i>10 years</i>
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner Sponsor	Kristina Newhouse Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

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

The purpose of this program is to replace aging Distributed Control Systems (DCS), Programmable Logic Controllers (PLC) and meters. DCSs and PLCs, referred to as controllers, are used throughout Avista's generating facilities to control and monitor Avista's generating units and auxiliary systems. Each generating unit and station service has a meter that measure MWh and MVARh. Controllers collect meter data that is used in logic programs. Controllers and meters used in generating facilities to automate, control, and monitor are aging and introducing an increase in hardware, software, and communication failures that limit Avista's ability to operate generating facilities reliably. The aging hardware of concern requires computer drivers that do not fit in new computers therefore we are required to operate computers with legacy operating systems. This creates a Cyber Security risk.

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

The major driver of this business case is Asset Condition. Outdated controllers have modules that are over 20 years old and spare parts are limited. Incorporating aging controllers and meters into modern designs is limited and often not possible. Improving the asset condition in this case will improve reliability within the generating facilities.

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

Replacing controllers and meters with new standards will reduce cyber security risk identified in section 1.1 and unexpected plant outages that require emergency repair with like equipment. Planned projects to replace aging controllers and meters before they fail will allow for more efficient upgrades with standardized hardware and software that engineers and technicians are trained on.

Automation Replacement

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.

Replacing hardware before it fails and software before it introduces a security risk while moving toward our standardized controllers and meters will be a success. In the past we've planned on upgrading controllers and meters during unit overhauls but this pace is slow when equipment is 20 years old and spare parts are not readily available. The intent of this business case is to increase the number of controllers and meters being replaced today which is about 1-3 controllers and meters a year.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
<i>[Recommended Solution] Upgrade Controllers and Meters</i>	<i>\$6.5M</i>	<i>01 2018</i>	<i>12 2025</i>
<i>[Alternative #1] Spare Parts Refurbishment / Do Nothing</i>	<i>\$100k/year</i>	<i>01 2018</i>	<i>NA</i>
<i>[Alternative #2] Software Upgrade</i>	<i>\$2.5M</i>	<i>01 2018</i>	<i>12 2025</i>

Alternative 1 is the preferred alternative. It includes replacing all aging controllers and meters proactively on a schedule that takes into account resources, outage availability, and EIM schedule demands. This option addresses aging hardware and software concerns as well as the cyber security vulnerabilities.

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

Information that was considered for this capital request included information from various individuals throughout the company. Technicians shared their challenges maintaining aging controllers and utilizing used spare parts that are often not reliable. It included feedback from operators that have concerns with keeping their plants running using 20 year-old controllers they depend on. Engineers expressed the design limitations they face when asked to install modern systems that tie into outdated technology. IT Security Engineers shared their concerns with technician requiring computers that operate Windows 95 and XP to access the controllers using the software required.

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). Include any known or estimated reductions to O&M as a result of this investment.

The requested capital cost for this program takes into consideration that project costs vary depending on the complexity of the controller and meter. Limited resources for design and construction as well as available outages make it necessary for upgrades to be spread out over many years. Upgrading controller & meters will reduce forced outages due to failures and unplanned O&M expenses.

Controllers that need to be replaced that are not part of a larger project in include:

- Upper Falls Unit 1 – design 2019,2020 / Construction tentatively scheduled for 2021
- Control Works – design 2019,2020 / Construction tentatively scheduled for 2021

Automation Replacement

- Boulder Park Balance of Plant - design 2020, 2021 / Construction tentatively scheduled for 2022
- Post Falls Balance of Plant - TBD
- Noxon Rapids Units 1-5 - TBD
- Coyote Springs Unit 2 -TBD

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

Additional resources are required in order to maintain a schedule and consistently meet the objectives. Engineering will require a designer to develop new logic programs and designs for installations. The Protection Control Meter Shop will need a resource to install and commission the PLC programs. The capital cost takes into account resources needed to perform designs and installations. It also takes into consideration feasibility of plant outages as projects are spread out over time.

This project will benefit Power Supply and System Operations as they are responsible for dispatching power from Cabinet Gorge plant to meet contractual obligations and managing the day-to-day transmission system operational requirements. It will also benefit engineering and the shops as they are responsible for providing maintenance and support with the generating facilities.

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

Alternative 1 is to maintain existing controllers and meters as we currently do today. This includes replacing controller modules as they fail with old spare parts or refurbish third party parts. Maintaining spare parts allows us to continue using existing infrastructure and logic programs but it does not resolve the long-term issue which is aging equipment that will eventually no longer be available. The risk of outages at undesirable times to replace failed parts becomes more likely the longer the aging hardware is in service. This alternative also does not resolve the issue with computers that have unsupported operating systems and are considered a cyber security risk.

Alternative 2 is to upgrade software on the controllers. This would include replacing each system's software that runs on Windows 95 and Windows XP with a separate software for each platform that runs on Windows 10. This will mitigate the software and cyber security issue but not the aging hardware issue. Outages would be required, and the new logic programs would need to be rewritten and fully commissioned. Upgrading the Bailey software and the Modicon software do not align with our standard PLC platform that our engineers and technicians are trained on. This would introduce two new software applications. Efficiency to troubleshoot and resolve issues in a timely manner could be impacted.

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 work began in 2018. This business case has funded the replacement of five outdated controllers over the last 3 years. These five controllers are in addition to 10 other controllers that have been replaced as part of other large capital projects. Most designs take place one year with installation and transfer to plant the following year upon completion of the project.

Automation Replacement

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

By proactively replacing aging controllers and meters we are able to increase reliability within our generating facilities. This program safely, responsibly, and affordably improves our customers' lives through innovative energy solutions.

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 prudence will be reviewed and re-evaluated throughout the project

The controllers & meters are both single point failures. If these devices fail they will cause either a single unit outage or a wider plant outage. If spare parts, from the limited supply on hand, can be found then the outage can be minimized but operating generating facility on outdated equipment requiring computers with unsupported operating systems is not sustainable, responsible, or cost effective, and exposes the generating facilities to unnecessary risk.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholders that interface with the Automation Replacement Business Case include:

- Controls Engineering
- SCADA Engineering
- Mechanical Engineering
- Project Management
- Network Engineering
- Network Operations
- PCM Shop
- Electric Shop
- Mechanic Shop
- Telecom Shop
- Hydro Operations
- Thermal Operations

2.8.2 Identify any related Business Cases

This business case does not replace any business cases but it is related to the HMI Control Software business case. As new control software and computers with Windows 10 are planned to be installed over the next couple years they need to communicate to controllers and meters. The oldest of the aging controllers require computer drivers that do not fit in new computers.

Automation Replacement

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Each project will have a project manager and steering committee for ongoing vetting. The steering committee for each project will consist of the Controls Engineering Manager, the Protection Control Meter Technician Foreman, the SCADA Engineering Manager, and either the Spokane River Plant Operations Manager, Cabinet Gorge Plant Operations Manager, Noxon Rapids Plant Operations Manager, Lower Spokane River Plant Operations Manager, or Thermal Operations Plant Manager.

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

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

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

Project decisions will be coordinated by the project manager. The Steering Committee will be advised when necessary. Regular updates will be provided to the Steering Committee by the project manager as project scope, schedule and budget are defined, and through the course of the project execution.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the [Automation Replacement](#) 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: *Kristina Newhouse* Date: 8/3/2020
 Print Name: Kristina Newhouse
 Title: Controls Engineering Manager
 Role: Business Case Owner

Signature: *Andrew Vickers* Date: 8/3/2020
 Print Name: Andy Vickers
 Title: Director of GPSS
 Role: Business Case Sponsor

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

Automation Replacement

Template Version: 05/28/2020

Base Load Hydro

EXECUTIVE SUMMARY

Avista’s Base Load Hydro plants are all located on the upper Spokane River and are “run of river” plants which means they have little to no storage capacity and their operation is subjected to the flow in the Spokane River and the lake level requirements of Lake Coeur d’Alene, upstream of the plants. The facilities considered in this program are: Post Falls, Upper Falls, Monroe Street and Nine Mile Hydroelectric Developments. This program also includes capital projects at the Generation Control Center and on the Generation Control Network. It can also include some projects at the Post Street 115kV Substation where the two downtown hydro plants are tied into the grid.

The 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 are 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 our 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	Updated for 2022-2026 Capital Plan	6/22/21	

Base Load Hydro

GENERAL INFORMATION

Requested Spend Amount	\$5,432,500
Requested Spend Time Period	5 years
Requesting Organization/Department	C07 / GPSS
Business Case Owner Sponsor	Bob Weisbeck Andy Vickers
Sponsor Organization/Department	C07 / 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 Base Load 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 cost-effective 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 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.

Base Load Hydro

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 66% and Failed Plant, approximately 34%. Projects are typically completed within the calendar year.

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 Committee.

Option	Capital Cost	Start	Complete
Regulating Hydro Program	\$5,535,000	<i>01/2022</i>	<i>12/2026</i>
Individual Capital Projects	\$5,535,000	<i>01/2022</i>	<i>12/2026</i>
Perform O&M maintenance	0		

Base Load 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 \$1,127,500, especially based on the age of the Base Load Hydro plants.

The drivers of the projects selected to be funded by this program are mix Asset Condition (approximately 66%) and Failed Plant (34%). 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 \$1,127,500. In order support the budget constraints of the department, this amount has been reduced by 10% for 2022. Projects with the lowest risk will be postponed during this period. The projects in this program typically take place within the calendar.

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.

Base Load Hydro

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 20 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. Work performed in and around the dams that require outages 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 to small to medium size projects with the objective of keeping our hydroelectric plants reliable and available. This enables these plants to affordably support the power needs of our company and our customers. By taking care of these facilities 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.

Base Load Hydro

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 prudence will be reviewed and re-evaluated throughout the project

Review of the program budget has revealed that a realistic annual budget is \$1,127,000. In order to support the capital budget goals of the GPSS department, this budget was reduced in the short term for 2022 by 10% for that 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 66%) and Failed Plant (34%). 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.

Base Load Hydro

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 prudence, 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 is followed 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.

Base Load Hydro

The undersigned acknowledge they have reviewed the Based Load Hydro Program 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: *R. S. Weisbeck* Date: 6/22/2021
 Print Name: R. S. Weisbeck
 Title: Manager, Hydro Ops and Maintenance
 Role: Business Case Owner

Signature: *Andrew Vickers* Date: 7/6/2021
 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

Base Load Thermal Program 2022 - 2026

EXECUTIVE SUMMARY

This business case request is for Avista's base load thermal plants: **Kettle Falls** and **Coyote Springs 2**. This program 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. Smaller and emergent projects planned for Kettle Falls are identified and prioritized through their plant Budget Committee. The plant Budget Committee utilizes an in-house Maintenance Project Review scoring matrix.

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

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

VERSION HISTORY

Version	Author	Description	Date	Notes
<i>Draft</i>	<i>Greg Wiggins</i>	<i>Initial draft of original business case</i>	<i>7/8/2020</i>	
	<i>Mike Mecham</i>	<i>Updated</i>	<i>7/6/2021</i>	<i>For years 2022 - 2026</i>

Base Load Thermal Program 2022 - 2026

GENERAL INFORMATION

Requested Spend Amount	\$13,950,000
Requested Spend Time Period	<i>5 years</i>
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?

Due to the age and continuous use of the base load thermal 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 thermal 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 thermal 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.

Base Load Thermal Program 2022 - 2026

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.

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. Projects are typically completed in the calendar year.

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 2022-2026; to “keep the lights on”.

Option	Capital Cost	Start	Complete
<i>Base Load Thermal Program</i>	<i>13,950,000</i>	<i>01/2022</i>	<i>12/2026</i>
<i>Individual Capital Projects</i>	<i>13,950,000</i>	<i>01/2022</i>	<i>12/2026</i>

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

2.1

Review of the recent program budget has revealed the a realistic annual budget is \$3,100,000. In order to support the capital budget goals of the GPSS department, this budget has been reduced by 10% to \$2,790,000 for years 2022 through 2026. Projects with lower risk will be delayed through this period.

Base Load Thermal Program 2022 - 2026

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 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 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 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.

Base Load Thermal Program 2022 - 2026

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 Kettle Falls and Coyote Springs 2 typically take place during the annual outages, which are typically in May-June of each year.

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 to small to medium size projects with the objective of keeping our thermal plants reliable and available to support the power needs of our company and our customers affordably. By doing this we support our mission of improving our customer's lives through innovative energy solutions which includes thermal generation. By 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 prudence will be reviewed and re-evaluated throughout the project

Review of the recent program budget has revealed the a realistic annual budget is \$3,100,000. In order to support the capital budget goals of the GPSS department, this budget has been reduced by 10% to \$2,790,000 for years 2022 through 2026. 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 and Failed Plant. 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

Base Load Thermal Program 2022 - 2026

2.8.2 Identify any related Business Cases

None.

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, Asst 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 “common” 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, 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 prudence, 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.

Base Load Thermal Program 2022 - 2026

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 prudence, 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

Base Load Thermal Program 2022 - 2026


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

Signature:  Date: 7/6/2021

Print Name: Thomas C Dempsey

Title: Mgr. Thermal Operations & Maintenance

Role: Business Case Owner

Signature:  Date: 7/6/2021

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

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 sections 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.

Cabinet Gorge 15kV Bus Replacement

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

Signature:  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 Dam Fishway

EXECUTIVE SUMMARY

The Clark Fork Settlement Agreement (CFSA) and FERC License require Avista to implement the Native Salmonid Restoration Plan (NSRP), which includes a step-wise approach to investigating, designing and implementing fish passage at the Clark Fork Project. Appendix C of the CFSA commits Avista to fund Fishway design and construction as well as annual operations. Fish passage is intended to restore connectivity of native salmonid species in the lower Clark Fork watersheds. During relicensing the U.S. Fish & Wildlife Service (USFWS) reserved its authority under Section 18 of the Federal Power Act to require fish passage at both Noxon Rapids and Cabinet Gorge dams, in order to pursue the NSRP more collaboratively. Those efforts, including involvement of native American tribes and state agencies, as well as other stakeholders, continued over 15 years to the current project.

The Agreement and License support all electric customers in Washington and Idaho by authorizing the continued operation of Noxon and Cabinet dams. In Amendment No. 1 to the CFSA, Avista agreed to construct and operate a permanent upstream fishway facility, consistent with the objective and purpose of the design approved by the Design Review Team (DRT) on January 13, 2013, and modified to include a two-chamber trap and siphon water supply approved by the DRT in July 2017. Any subsequent changes in design that may affect the design criteria identified in the final Basis of the Design Report will require approval by the USFWS. This agreement provides protection for Avista from being ordered to build alternative facilities and also satisfies obligations under the Endangered Species Act as well as Federal Power Act Section 18. Approval of this business case and the estimated total project cost of \$64.3 million will benefit our customers by maintaining compliance with the CFSA and FERC License and subsequent agreements, which provide operational flexibility at Avista's Noxon and Cabinet Gorge Facilities.

VERSION HISTORY

Version	Author	Description	Date	Notes
<i>Draft</i>	<i>Michael Truex</i>	<i>Initial draft of original business case</i>	<i>6/30/2020</i>	
<i>1.0</i>	<i>Michael Truex</i>	<i>Completed business case</i>	<i>7/28/2020</i>	<i>Reviewed by Nate Hall</i>
<i>1.1</i>	<i>Michael Truex</i>	<i>2021 Update</i>	<i>7/9/2021</i>	<i>Reviewed by Nate Hall</i>
<i>2.0</i>				

Cabinet Gorge Dam Fishway

GENERAL INFORMATION

Requested Spend Amount	\$63.7M
Requested Spend Time Period	2013 - 2023
Requesting Organization/Department	B04 / Clark Fork License
Business Case Owner Sponsor	Nate Hall Bruce Howard
Sponsor Organization/Department	A04 / Environmental Affairs
Phase	Execution
Category	Project
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

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

Design and Construction of the Cabinet Gorge Dam Fishway (CGDF) that fulfills the upstream fish passage requirements identified in the Clark Fork Settlement Agreement (CFSA) and FERC License No. 2058 issued for Cabinet Gorge HED in 2001.

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

The project is driven by the CFSA and FERC License issued for Cabinet Gorge HED in 2001. The CFSA and FERC license were amended in 2017 to establish final terms and conditions with regulatory agencies having jurisdiction as to specifics of the project. The project will start operation in 2022 and operate at least through the term of the FERC license (2045).

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

Avista, working closely with interested stakeholder groups, began implementation of an Upstream Fish Passage Program for Bull Trout in 2001 as part of Appendix C of the CFSA. A similar program for Westslope Cutthroat Trout was initiated in 2015, and the results of this study will help inform future fish passage decisions. Bull Trout are listed as threatened under the Endangered Species Act and Westslope Cutthroat Trout are a species of species concern in both Montana and Idaho. A number of fish collection methods have been employed to capture these fish prior to upstream transport. The use of these methods has resulted in some level of fish capture success; however, there is evidence the majority of the fish that are approaching Cabinet Gorge Dam are not being captured and not all fish that are captured are captured the first time they approach the dam. The Cabinet Gorge Dam Fishway (CGDF) is being constructed to capture a larger

Cabinet Gorge Dam Fishway

number of the migratory native salmonids that are approaching Cabinet Gorge Dam. The goal of construction and operation of the CGDF is to provide timely and effective upstream passage for native trout species in support of broad native salmonid recovery and connectivity in the lower Clark Fork watershed. The signatories to the CFSA agree that the construction and operation of upstream and downstream fishways, and the provisions in Amendment No. 1 to the CFSA is in the public interest and that it satisfies various agency authorities applicable to the Project. Critical among the authorities cited are Section 18 of the Federal Power Act, the Endangered Species Act, the Clean Water Act, state fishway and transport regulations, and USFWS's 1999 Biological Opinion for licensing and operating the Project for the term of the License.

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.

Avista agreed to construct and operate the CGDF as part of Amendment No. 1 to the CFSA, consistent with the objective and purpose of the "100% design" approved by the Design Review Team on January 13, 2013, modified to include a two-chamber trap and siphon water supply approved by the Design Review Team in July 2017, that is compliant with National Marine Fisheries Service fish passage standards. Any changes to that design will require the approval of USFWS if the change would impact criteria identified in the final Basis of Design Report. The Basic Monitoring Plan and transport protocols may be modified from time to time by the MC; however, Amendment No. 1 to the CFSA makes clear that the transport protocols must be approved by USFWS for Bull Trout, and must be consistent with the detailed pathogen sampling and upstream transport protocols set forth in Section 5 and Appendix 2 of Amendment No. 1 to the CFSA. Therefore, the success for this project would be Avista's construction of the CGDF, as specified in Amendment No. 1 to the CFSA, and willingness to conduct upstream fish passage through operation of the CGDF or through other methods fully satisfying any obligation Avista may have to mitigate for the Cabinet Gorge Dam's blockage of upstream fish passage for the term of the License and any subsequent annual licenses. Parties may request minor modifications to the facility, but agree not to require Avista to replace the CGDF or install alternative fishway facilities or to make structural or operational changes to Cabinet Gorge generating facilities or its reservoir. In the event the CGDF does not capture native salmonids in a manner that is safe, effective and timely, the parties agree that Avista will alternatively recommence electrofishing, operation of the Cabinet Gorge hatchery ladder, and/or hook-and-line fishing below Cabinet Gorge Dam.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The Clark Fork Settlement Agreement (CFSA) under FERC License No. 2058 issued for Cabinet Gorge HED in 2001, and Amendment No. 1 of the Clark Fork Settlement Agreement both stipulate that Avista will construct a fish passage facility for Bull Trout at Cabinet Gorge Dam. As such, there

Cabinet Gorge Dam Fishway

is no alternative to constructing the facility. Not doing so could jeopardize the FERC license and thus the ability to generate power at Cabinet Gorge Dam. The current design is the result of years of consultation, as well as value engineering, with the intent to build an effective permanent facility at the lowest cost.

ASSUMPTIONS & EXPECTED CONDITIONS

- No alternative exists for construction of a fish passage facility at Cabinet Gorge Dam (see above). This plan is a result of our license requirements and subsequent negotiations.
- If Avista does not build a fish passage facility at Cabinet Gorge Dam FERC could issue orders, penalties or even rescind our operating license.
- If Avista does not build a fish passage facility at Cabinet Gorge Dam the USFWS could take legal action under Section 18 to order Avista to build the facility, with none of the assurances enacted by agreement in the CFSA Amendment.
- Operations of the CGDF will be performed by the Environmental Affairs Department's staff.

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. (N/A)

No alternative exists for construction of a fish passage facility at Cabinet Gorge Dam (see above). The values below are for the construction bids and do not include full Parametric or Analogous estimates with Avista Labor, contracted Engineering, Overhead Loadings, and AFUDC.

Option	Capital Cost	Start	Complete
<i>MJ Kuney Original Bid (no bond, tax, or risk registry)</i>	<i>\$41.8M</i>	<i>03/2019</i>	<i>12/2021</i>
<i>Slayden Original Bid (no bond, tax, or risk registry)</i>	<i>\$22.8M</i>	<i>03/2019</i>	<i>12/2019</i>
<i>Slayden GMP (includes tax, bond, and risk registry)</i>	<i>\$24.9M</i>	<i>03/2019</i>	<i>12/2019</i>

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

Once engineering support during construction, construction management and inspection, and construction contracts were executed, the budget estimate was developed using Parametric and Analogous estimating methods scaled over the time of the project with a cost loaded construction schedule. Then Avista anticipated labor, respective labor loadings, capital overhead loadings, and AFUDC were applied per the project accounting and capital cost structure. 2020 construction delays related to the FERC Left Thrust Block Stability concerns and engineering analysis, as well as, repairs to the temporary cofferdam have negatively impacted the construction schedule and project expenditure schedule. As a result, \$1.9M of planned spend in 2021 has slid into 2022 and an additional need of \$235K in 2023 for the construction schedule slide, as well as, the FERC project closeout period post construction startup support. Due to risk mitigation and less risk

Cabinet Gorge Dam Fishway

registry being utilized the \$1.9M push in 2021 has resulted in a need for an additional \$615K in 2022 and \$235K in 2023. This is ultimately resulting in a total cost of capital of \$63.7M.

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.**

Operations and maintenance costs will not be covered as part of this project and will be managed through the ongoing implementation of the CFSA and License. Capital costs forecasted annual include engineering service during construction, construction management, special inspection, construction, startup, commissioning, and nine months of post commissioning troubleshooting and engineering support.

The project is anticipating the following capital costs:

- 2013 – 2018: \$19.56M
- 2019: \$10.87M
- 2020: \$12.93M
- 2021: \$14.7M
- 2022: \$5.55M
- 2023: \$235K

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

There is currently no Avista communication network at the Fish Handling and Holding Facility. Engineering and IT will explore options to get communications to and from the CGDF and the Handling and Holding Facility. The final facility will be managed and operated by the Environmental Affairs staff at the Clark Fork Natural Resource Office. In coordination with other departments, the local Cabinet Gorge Dam staff will assist in performing some startup activities, maintenance, and trouble shooting. Work larger in magnitude will be performed by GPSS craft shops, and or subcontracted to local contractors.

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

Alternatives and upstream fish passage and facility location were evaluated and discussed in the design development and partnership with the CFSA Management Committee and respective agencies involved. The project design package was originally bid in late 2015. Due to high bid prices and timing, the bids were rejected in early 2016. The project team then met with the lowest cost bidder and went through a value engineering process through July 2016. The final design was then completed from January 2017 to June 2018. An early contract was executed with Slayden Construction to complete the cofferdam design for FERC and USACE submission, support in permitting and develop a Guaranteed Maximum Price (GMP) contract based on the Stantec 100% design documents.

Cabinet Gorge Dam Fishway

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.

2020 construction delay has shifted the substantial completion and in-service date to late April to early May 2023, final construction completion July 2023, and FERC project closeout October 2023.

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

The delivery of this project is highly important in the sustainability and operations of our Clark Fork River facilities and operating them safely and responsibly. The project will focus of the people responsible the delivering with a strong emphasis on performance. This nature of the project demands a collaborative environment with the wide array of key stakeholder groups. These efforts aligns with Avista values of collaboration and environmental stewardship.

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 prudence will be reviewed and re-evaluated throughout the project

The project budget and total cost will be regularly reviewed with the project steering committee, as well as, receive approvals as described below for any changes in scope and cost.

Prudence is also measured by remaining in compliance the FERC License and Clark Fork Settlement Agreement, such that we can continue to operate the Clark Fork project 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

- GPSS Engineering; Electrical, Controls, Mechanical, Civil, Dam Safety
- Distribution Engineering
- Hydro Operations
- Environmental, Permitting, and Licensing
- Master Scheduler
- Asset Management
- Project Accounting, Finance, and Rates
- Supply Chain and Legal
- Corporate Communications
- Construction Inspection and Project Management

2.8.2 Identify any related Business Cases

This project was part of the Clark Fork Settlement Agreement business case until 2018 when it was separated into its own business case.

Cabinet Gorge Dam Fishway

3.1 Steering Committee or Advisory Group Information

- Project Sponsor:
 - Bruce Howard – Senior Director Environmental Affairs

- Steering Committee:
 - Bruce Howard – Senior Director Environmental Affairs
 - Andy Vickers – Director GPSS
 - Nate Hall – Manager Clark Fork License
 - Jacob Reidt – Manager Project Delivery

- Project Manager:
 - Michael Truex – Generation Project Delivery

- Key Project Stakeholders:
 - Bob Weisbeck – Manager of Hydro Ops & Maintenance
 - Guy Paul – Senior Engineer II
 - Andrew Burgess – Manager Plant Operations Hydro – Cabinet Gorge
 - Eric Rosentrater – Manager Safety, Training Operations & Labor Specialist
 - Greg Hesler – Senior Counsell II
 - Michele Drake – Supervisor Hydro Compliance
 - Laroy Dowd – Chief Operator
 - Heide Evans – Environmental Budget Specialist
 - Rod Price – Manager Real Estate
 - Shawna Kiesbuy – Senior Manager Network Engineering
 - Steve Lentini – Sr Hydro Ops Engineer II, Power Supply
 - Pat Maher – Sr Hydro Ops Engineer II, Power Supply
 - Scott Kinney – Director Power Supply

- Project Team:
 - Shana Bernall – Supervisor Biologist NE
 - Lisa Vollertsen – Environmental Scientist I
 - Guy Paul – Senior Engineer II (Avista Project Technical Lead & QCIP Mgr)
 - Matthew Moots (IT/ET) – Project Manager
 - Lindsay Fracas – Associate Project Manager
 - Ryan Traylor – Project Engineer
 - Michael Truex – Project Manager
 - Clint Smith – Stantec PM, Engineer of Record
 - James Larsen – CM/Inspector STRATA & All West
 - Slayden Construction Inc - Contractor

Cabinet Gorge Dam Fishway

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

The project will be led by the core project team. Any changes to scope, schedule and budget will be submitted for approval to the steering committee and with the respective cost thresholds as defined in the table below.

Manager/Budget Owner	\$25,000 or less	Nate Hall
Director/Steering Committee	\$25,000 - \$99,999	Reidt, Hall, Vickers, Howard
Vice President	\$100,000 - \$499,999	Jason Thackston
Sr. VP/CFO	\$500,000 - \$2,999,999	Jason Thackston
President	\$3,000,000 and above	Dennis Vermillion

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

The project is utilizing the Project Change Log to track and manage all Project Change Requests (PCR) associated with the delivery of the construction project. The PCR describes the need for change, supplemental documentation, related project artifacts, change order proposals, and any other pertinent information. PCR's are then signed for approval by the project approval thresholds, and then processed against the project risk registry, and or contract amendment with the contractor.

The undersigned acknowledge they have reviewed the *Cabinet Gorge Dam Fishway* 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** Digitally signed by Nate Hall
Date: 2021.07.20 15:19:34
-06'00' Date: _____

Print Name: Nate Hall

Title: Mgr Clark Fork License

Role: Business Case Owner

Signature: **Bruce F Howard** Digitally signed by Bruce F
Howard
Date: 2021.07.20 14:58:45 -07'00' Date: _____

Print Name: Bruce Howard

Title: Sr Dir Environmental Affairs

Role: Business Case Sponsor

Cabinet Gorge Dam Fishway

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

Template Version: 05/28/2020

Cabinet Gorge Unit 3 Protection & Control Upgrade

EXECUTIVE SUMMARY

Cabinet Gorge Hydroelectric Development (HED) is the second largest such generating plant in Avista's hydropower fleet. It is located on the Clark Fork River in Bonner County, Idaho. With four generators, it has a 270 MW output capacity. Built in 1952, the plant has retained most of its original equipment which is now aging and at end of life. This plant was designed for base load operation but, today is called on to not only provide load but to quickly change output in response to the variability of wind generation, to changing customer loads and other regulating services needed to balance the system load requirement and assure transmission system reliability.

In order to respond to these new demands, it is necessary to upgrade protection and controls equipment. This equipment includes speed controllers (governors), voltage controls (automatic voltage regulation a.k.a. AVR), primary unit control systems (Programmable Logic Controllers) and the protective relay system all of which serve to increase communications and reaction time. Timing for this work is not unrelated to Avista's entrance into the Energy Imbalance Market (EIM). The risks for not completing these upgrades include an inability to quickly respond to market demands thereby jeopardizing Avista's ability to serve its customers.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Glen Farmer	Initial draft of original business case	8/1/2020	

Cabinet Gorge Unit 3 Protection & Control Upgrade

GENERAL INFORMATION

Requested Spend Amount	\$750,000
Requested Spend Time Period	1 year, 2021
Requesting Organization/Department	GPSS
Business Case Owner Sponsor	Glen Farmer 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 problem being addressed is the protection and control systems on Cabinet Gorge Unit 3. These systems have reached end of life and serve to provide start, stop, run, change load, react to system changes and protect the generator from electrical disturbances.

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.

The current protection and controls systems were installed in the early 1990's. These systems can no longer be maintained due to the manufacturer no longer supporting the equipment. The customer benefits through higher reliability of Unit controls: i.e. reduced unexpected outages and manufacturer support of upgraded equipment.

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

This is an overall protection and control upgrade that addresses all of the components of the generator and turbine thereby ensuring that each auxiliary system connects and communicates as one. If individual failures were realized, they would be addressed with a patchwork of components that would not connect and communicate with one another. At some point in time, we would be forced to rework the systems as a whole.

Cabinet Gorge Unit 3 Protection & Control Upgrade

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.

This protection and control upgrade mirrors thirteen previous upgrades at various plants throughout Avista's generating facilities. It provides consistency on the auxiliary systems for maintenance and troubleshooting. Reduced reliance on manufacturer support decreases overall maintenance costs for auxiliary equipment. Interchangeability of the equipment and knowledge transfer amongst electricians, mechanics, technicians and engineering plays a key role in reliability.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

No studies per se have been performed however, lessons learned from the previous thirteen upgrades have been incorporated into this design.

Option	Capital Cost	Start	Complete
Replace Unit Control, Monitoring and Protection System [CURRENT PLAN]	\$750,000	01/2021	04/2021
Replace Unit Control, Monitoring and Protection System, Reinsulate Pole Pieces and Stator Re-wedge [ALTERNATIVE PLAN]	\$1,750,000	01/2021	07/2021

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

Capital planning for this work consisted of bids from manufacturers to determine best cost and schedule. Consistent communication platform between auxiliary equipment was used to determine best compatibility. Information from previous projects was used to determine installation costs and schedules.

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.

Installation and commissioning of purchased equipment will take place in 2021. Maintenance costs will not be reduced but, Unit reliability will be improved through decreased outages.

Cabinet Gorge Unit 3 Protection & Control Upgrade

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

Design processes, purchasing processes, PI (IO to data historian) will be impacted, new control screens (HMI) for checkout and upgraded protection enables the protection group to have direct communication with the relays.

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

With regard to rebuilding the Pole Pieces, the temperature of the field did not exceed the designed temperature therefore there is no driver to rebuild the Pole Pieces. Measurements of the ripple springs used to keep the coils tight in the stator slots did not indicate a need to replace or re-wedge the stator.

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.

Work on this project is already underway having commenced in 2019. 2021 will continue with installation of procured equipment and commissioning. Unit 3 will be returned to service (used and useful) by April 2021.

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

Upgrading the protection and controls systems on Unit 3 at Cabinet Gorge contributes to the Safe and Responsible design, construction, operation and maintenance of Avista's generating fleet.

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 prudence will be reviewed and re-evaluated throughout the project.

We ranked this project based on a ranking matrix to ensure prudent consideration of costs, scheduling and personnel resources.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case.

Electric shop, mechanical shop, relay shop, engineering, Operations, SCADA, Protection, Environmental, Project Management and Power Supply.

Cabinet Gorge Unit 3 Protection & Control Upgrade

2.8.2 Identify any related Business Cases.

Cabinet Gorge Units 1, 2 and 4 Protection and Control upgrades

3.1 Steering Committee or Advisory Group Information

The Steering Committee consists of the following members: Manager of Project Delivery, Manager of Maintenance and Construction, Manager, Manager of Hydro Operations & Maintenance.

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

Persons providing oversight include: Generation Electrical Engineering Manager, Generation Controls Engineering Manager, General Foreman of Protection, Control and Meter technicians, Manager C&M - Electric Shop, Cabinet Gorge Plant Manager, and Manager Engineering Protection

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

The persons identified in Section 3.2 will be called on to evaluate recommendations raised from the stakeholder group. Documented decisions will be stored in the project folder located on the department network drive.

Cabinet Gorge Unit 3 Protection & Control Upgrade

The undersigned acknowledge they have reviewed the Cabinet Unit 3 Protection & Control Upgrade 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 S. Farmer Date: 7/31/2020
 Print Name: Glen Farmer
 Title: Manager Electrical Engineering
 Role: Business Case Owner

Signature: *Andrew Vickers* Date: 7/31/2020
 Print Name: Andy Vickers
 Title: Director, GPSS
 Role: Business Case Sponsor

Signature: *R. S. Weisbeck* Date: 8-3-2020
 Print Name: Bob Weisbeck
 Title: Manager, Hydro Operations and Maintenance
 Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Cabinet Gorge Unit 4 Protection & Control Upgrade

EXECUTIVE SUMMARY

Cabinet Gorge Hydroelectric Development (HED) is the second largest such generating plant in Avista's hydropower fleet. It is located on the Clark Fork River in Bonner County, Idaho. With four generators, it has a 270 MW output capacity. Built in 1952, the plant has retained most of its original equipment which is now aging and at end of life. This plant was designed for base load operation but, today is called on to not only provide load but to quickly change output in response to the variability of wind generation, to changing customer loads and other regulating services needed to balance the system load requirement and assure transmission system reliability.

In order to respond to these new demands, it is necessary to upgrade protection and controls equipment. This equipment includes speed controllers (governors), voltage controls (automatic voltage regulation a.k.a. AVR), primary unit control systems (Programmable Logic Controllers) and the protective relay system all of which serve to increase communications and reaction time. Timing for this work is not unrelated to Avista's entrance into the Energy Imbalance Market (EIM). The risks for not completing these upgrades include an inability to quickly respond to market demands thereby jeopardizing Avista's ability to serve its customers.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Glen Farmer	Initial draft of original business case	8/1/2020	

Cabinet Gorge Unit 4 Protection & Control Upgrade

GENERAL INFORMATION

Requested Spend Amount	\$2,000,000
Requested Spend Time Period	1 year, 2021
Requesting Organization/Department	GPSS
Business Case Owner Sponsor	Glen Farmer 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 problem being addressed is the protection and control systems on Cabinet Gorge Unit 3. These systems have reached end of life and serve to provide start, stop, run, change load, react to system changes and protect the generator from electrical disturbances.

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.**

The current protection and controls systems were installed in the early 1990's. These systems can no longer be maintained due to the manufacturer no longer supporting the equipment. The customer benefits through higher reliability of Unit controls: i.e. reduced unexpected outages and manufacturer support of upgraded equipment.

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

This is an overall protection and control upgrade that addresses all of the components of the generator and turbine thereby ensuring that each auxiliary system connects and communicates as one. If individual failures were realized, they would be addressed with a patchwork of components that would not connect and communicate with one another. At some point in time, we would be forced to rework the systems as a whole.

Cabinet Gorge Unit 4 Protection & Control Upgrade

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.

This protection and control upgrade mirrors thirteen previous upgrades at various plants throughout Avista's generating facilities. It provides consistency on the auxiliary systems for maintenance and troubleshooting. Reduced reliance on manufacturer support decreases overall maintenance costs for auxiliary equipment. Interchangeability of the equipment and knowledge transfer amongst technicians plays a key role in reliability.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

No studies per se have been performed however, lessons learned from the previous thirteen upgrades have been incorporated into this design.

Option	Capital Cost	Start	Complete
Replace Unit Control, Monitoring and Protection System [CURRENT PLAN]	\$2,000,000	01/2021	04/2022
Replace Unit Control, Monitoring and Protection System, Reinsulate Pole Pieces and Stator Rewedge [ALTERNATIVE PLAN]	\$3,000,000	01/2021	07/2022

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

Capital planning for this work consisted of bids from manufacturers to determine best cost and schedule. Consistent communication platform between auxiliary equipment was used to determine best compatibility. Information from previous projects was used to determine installation costs and schedules.

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.

Installation and commissioning of purchased equipment will take place in 2021. Maintenance costs will not be reduced per se but, Unit reliability will be improved through decreased outages.

Cabinet Gorge Unit 4 Protection & Control Upgrade

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

Design processes, purchasing processes, PI (IO to data historian) will be impacted, new control screens (HMI) for checkout, upgraded protection enables the protection group to have direct communication with the relays.

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

With regard to rebuilding the Pole Pieces, the temperature of the field did not exceed the designed temperature therefore there is no driver to rebuild the Pole Pieces. Measurements of the ripple springs still needs to be performed to determine the necessity of a rewedge.

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.

Work on this project is already underway having commenced in 2019. 2021 will continue with installation of procured equipment and commissioning. Unit 3 will be returned to service (used and useful) by April 2021.

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

Upgrading the protection and controls systems on Unit 3 at Cabinet Gorge contributes to the Safe and Responsible design, construction, operation and maintenance of Avista's generating fleet.

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 prudence will be reviewed and re-evaluated throughout the project.

We ranked this project based on a ranking matrix to ensure prudent consideration of costs, scheduling and personnel resources.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case.

Electric shop, mechanical shop, relay shop, engineering, Operations, SCADA, Protection, Environmental, Project Management and Power Supply.

Cabinet Gorge Unit 4 Protection & Control Upgrade

2.8.2 Identify any related Business Cases

Cabinet Gorge Units 1, 2 and 4 Protection and Control upgrades

3.1 Steering Committee or Advisory Group Information

The Steering Committee consists of the following members: Manager of Project Delivery, Manager of Maintenance and Construction, Manager, Manager of Hydro Operations & Maintenance.

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

Persons providing oversight include: Generation Electrical Engineering Manager, Generation Controls Engineering Manager, General Foreman of Protection, Control and Meter technicians, Manager C&M - Electric Shop, Cabinet Gorge Plant Manager, and Manager Engineering Protection

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

The persons identified in Section 3.2 will be called on to evaluate recommendations raised from the stakeholder group. Documented decisions will be stored in the project folder located on the department network drive.

Cabinet Gorge Unit 4 Protection & Control Upgrade

The undersigned acknowledge they have reviewed the Cabinet Unit 3 Protection & Control Upgrade 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 S. Farmer Date: 7/31/2020
 Print Name: Glen Farmer
 Title: Manager Electrical Engineering
 Role: Business Case Owner

Signature: *Andrew Vickers* Date: 7/31/2020
 Print Name: Andy Vickers
 Title: Director, GPSS
 Role: Business Case Sponsor

Signature: *R. S. Weisbeck* Date: 8-3-2020
 Print Name: Bob Weisbeck
 Title: Manager, Hydro Operations and Maintenance
 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
<i>Draft</i>	<i>Nate Hall</i>	<i>Initial draft of original business case</i>	<i>6/30/2020</i>	
<i>1.0</i>	<i>Nate Hall</i>	<i>Completed business case</i>	<i>7/23/2020</i>	
<i>1.1</i>				
<i>2.0</i>				

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

Clark Fork License

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
<i>Capital funding</i>	<i>\$5,318,068</i>	<i>01 2021</i>	<i>12 2021</i>
<i>Activity is mandatory – resulting in operational cost overage</i>	<i>\$0</i>	<i>01 2021</i>	<i>12 2021</i>

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 be 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

Clark Fork License

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 prudence will be reviewed and re-evaluated throughout the project

Prudence 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,

Clark Fork License

Sr. Director of Environmental Affairs, and

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

Coyote Springs LTSA

EXECUTIVE SUMMARY

Coyote Springs 2, one of Avista's wholly-owned Base Load Thermal power plants, is a Natural Gas fired combined cycle unit which has the capability to generate 300 MW. Coyote Springs 2 is equipped with automation to safely adjust unit output to match changing system loads and other types of services necessary to provide a stable electric grid.

The service code for the plant covered under the Coyote Springs Long Term Service Agreement (LTSA) is Electric Direct and the jurisdiction for the capital project is Allocated North serving our electric customers in Washington and Idaho.

The gas turbine at Coyote Springs 2 requires major overhauls every 32,000 operating hours to remain operable. Components are subject to extreme high temperatures and stress and must be serviced at the OEM specified intervals. A Long Term Service Agreement with the OEM (General Electric) was determined to be the most cost effective solution for customers. Originally effective in 2003, it has been renegotiated twice- in 2012 and 2015. This multi-year program covers the capital accruals required to execute the Long Term Service Agreement (LTSA) with GE for Coyote Springs Unit 2. Annual costs fluctuate because Avista pays on the number of fired hours that changes from year to year. Payments in 2021 will cover the estimated 1,416 operating hours that will accrue in January and February.

Based on the next major overhaul scheduled to begin in the Spring, 2021, the Combustion Turbine will have 32,000 operating hours since the last major overhaul and the second complete set of new components will be installed in the Combustion Turbine during that time. Once this maintenance is completed, and the new components have been installed, the payments under the LTSA will be transferred to the Operation and Maintenance budget to allow funds to rebuild the used components.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Mike Mecham	Initial draft of original business case	8/4/2020	
1.0				

GENERAL INFORMATION

Requested Spend Amount	\$509,760
Requested Spend Time Period	2021

Coyote Springs LTSA

Requesting Organization/Department	C06 / GPSS
Business Case Owner Sponsor	Thomas Dempsey Andy Vickers
Sponsor Organization/Department	C06 / GPSS
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

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

The gas turbine at Coyote Springs requires major overhauls every 32,000 operating hours to remain operable. Components are subject to extreme high temperatures and stress and must be serviced at the OEM specified intervals. When the initial LTSA was negotiated in 2003, the OEM had the most technical ability to service this LTSA, with the OEM (General Electric) was determined to be the most cost effective solution for customers.

1.2 Discuss the major drivers of the business case

The major drivers for this business case are Asset Condition. The LTSA program provides funding for capital projects that are required to support the safe, reliable, and efficient operation of the combustion turbine and supporting equipment.

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

This is the last year of multi-year capital accrual to install a second new set of combustion hardware. The accrual is based on a dollar amount per factored fired hour of the combustion turbine. The replacement timing of the next new set of equipment is following 32,000 hours of operation, therefore has the potential to fluctuate depending on Avista Power Supply needs. The 32,000 hour mark is projected to occur during Q1 of 2021, when the next set of new hardware will be installed. At year end of 2020, accruals to date will be slightly over \$11,000,000 since the accrual began in 2016, when the first set of new hardware was installed. \$509,760 is being requested to complete the accrual prior to the outage to install the new set of hardware

Coyote Springs LTSA

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.

By completing the OEM recommended replacement of combustion hardware following 32,000 operating hours, and continuing to perform annual inspections on components under high temperature and stress, better ensures the equipment will continue to operate until the next major overhaul following 32,000 operating hours.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

The gas turbine at Coyote Springs requires major overhauls every 32,000 operating hours to remain operable. Components are subject to extreme high temperatures and stress and must be serviced at the OEM specified intervals.

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.

The gas turbine at Coyote Springs 2 requires major overhauls every 32,000 operating hours to remain operable. Components are subject to extreme high temperatures and stress and must be serviced at the OEM specified intervals to continue safe, reliable and efficient operation.

Option	Capital Cost	Start	Complete
CS2 LTSA and negotiated work	\$20,000,000	2016	2040

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

In 2016 we performed an Advanced Gas Path upgrade on the combustion turbine that included further efficiency and output improvements at Coyote Springs 2. Changes to the machine extended the time between major overhauls and because of this we were able to negotiate additional cash discounts on the fired hour based LTSA payments. We also negotiated an extension of the LTSA to ~2040. By renegotiating the CS2 LTSA in 2015, the actual fired hours charge reduced 12.4%.

Coyote Springs LTSA

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.

\$509,760 that will accrued in 2021 will be combined with the previous 5 years of accruals earmarked for the CS2 LTSA. The entirety of the accruals will be transferred to plant in Q1 and Q2 of 2021 during the installation of the second complete set of new equipment will be installed.

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

All maintenance covered under this LTSA is the responsibility of GE, the OEM, whom Avista is under contract with to perform the tasks under identified in the LTSA.

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

When the CS2 LTSA was first negotiated and placed into action in 2003, and renegotiated in 2012, GE, the OEM had the appropriate technical ability to service the combustion turbine and associated equipment. As the industry grew, other market alternatives arose which allowed Avista to research alternatives. Knowledge of these alternatives allowed Avista to negotiate a substantial reduction over the initial contract price. GE was able to provide LTSA service, and upgrades, at a reduced rate.

In 2016 we performed an Advanced Gas Path upgrade on the combustion turbine that included further efficiency and output improvements at Coyote Springs 2. Changes to the machine extended the time between major overhauls and because of this we were able to negotiate additional cash discounts on the fired hour based LTSA payments. We also negotiated an extension of the LTSA to ~2040. By renegotiating the CS2 LTSA in 2015, the actual fired hours charge reduced 12.4%.

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 next set of new hardware is scheduled to be installed and transferred to plant in Q1 – Q2 of 2021.

Coyote Springs LTSA

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 accruals, based on operating hours, for the Long Term Service Agreement. The agreement in the LTSA includes already purchased and installed smaller upgraded equipment that increased efficiency and output.

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 prudence will be reviewed and re-evaluated throughout the project

The total requested amount was approved in 2015 following the LTSA renegotiation as the best alternative for Avista's customers. The reduction in cost per operating hour, coupled with improved efficiency of the combustion turbine, allowed a better alternative from what was previously agreed upon in the 2012 LTSA.

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, Power Supply, Systems Operations, and electric customers in Washington and Idaho.

2.8.2 Identify any related Business Cases

None

3.1 Advisory Group Information

The Advisory Group for the Coyote Springs LTSA consisted of Power Supply Management, GPSS Management, and the Vice President of Energy Resources. There are monthly Owners meetings with Avista management, General Electric and Portland General Electric contractors who review ongoing operations and monitor the status of the unit and planned activities as part of the LTSA.

Coyote Springs LTSA

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

The LTSA has guidance written in to the agreement that relates to equipment covered under the LTSA. Much of the equipment has OEM and industry standard replacement intervals that are adhered to. Other equipment is covered under the LTSA should an out of cycle replacement need occur, as well as items that are not Routine Maintenance. The governance of the LTSA is performed by Avista's Coyote Springs 2 manager, Portland General Electric management, and General Electric contract and service managers.

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

During monthly Coyote Springs 2 Owners Meetings that include PGE site management and GE LTSA representative, future spend items are discussed along with the combustion turbine performance. The maintenance and/or replacement cycle of the components listed in the LTSA are contractually agreed upon between Avista and GE.

The undersigned acknowledge they have reviewed the Peaking Generation Program 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:  Date: 08/05/2020

Print Name: Thomas C Dempsey

Title: Mgr. Thermal Operations & Maintenance

Role: Business Case Owner

Signature:  Date: 08/05/2020

Print Name: Andy Vickers

Title: Director GPSS

Role: Business Case Sponsor

Signature: _____ Date: _____

Coyote Springs LTSA

Print Name: _____
Title: _____
Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

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 interest 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 internal hot spots or arcing that could lead to catastrophic failure.
- **Reliability-** 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.

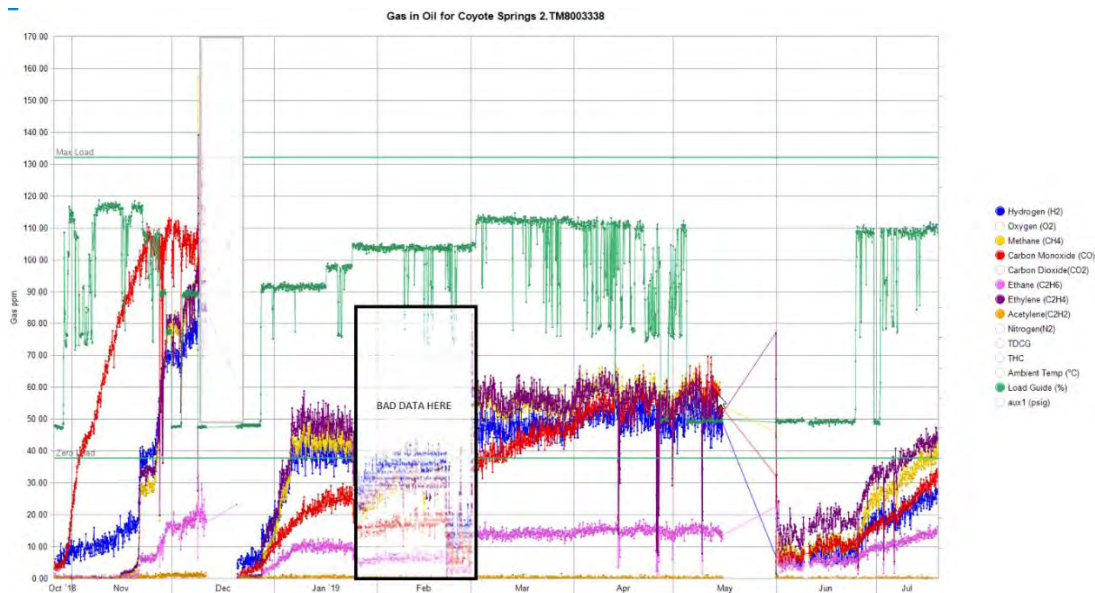
This project provides for replacement of the failed T3 as well as the currently operating but gassing T4. T3 failed catastrophically due to an internal fault. See Figure 1 below that clearly shows internal arcing damage. T4, which is of nearly identical construction as T3, is currently gassing at dangerous 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

CS2 Single Phase Transformer

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.

CS2 Single Phase Transformer

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 Infrastructure, 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 prudence 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 prudence 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 excerpt from that document is provided below:

Options	Capital Cost \$M / Plant Net Market Value \$M	
	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

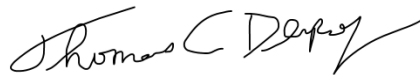
Executive level scope, schedule, & budget oversight is provided by the Steering Committee on a Quarterly basis. Ongoing senior management is provided by the Manager of Thermal Operations. Day to day project oversight is provided by the assigned Project Manager.

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 Manager 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:



Date: 7/10/2020

Print Name:

Thomas Dempsey

Title:

Manager, Thermal Operations

Role:

Business Case Owner

Signature:



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

Generation DC Supplied System Update

EXECUTIVE SUMMARY

The Generation DC Supplied System program covers all the generation and control facilities. It is the backbone for supplying power to the protective relays, breakers, controls and communication systems. With NERC requirements followed and design enhancements the DC system is being monitored, tested and remains reliable. Experience shows that we must continually monitor, review and maintain our DC system. The equipment manufactures gives an estimated life span to the batteries and auxiliary equipment. Some of these estimates have not hit the mark and have been changed out early due to failing tests or issues with the equipment. Proven manufactures are used to improve reliability and life. The risk of not approving this program would reduce the reliability of our generation and control facilities.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Glen Farmer	Initial version	4/10/2017	
2.0	Glen Farmer	Updated timeline from 5-year plan.	8/1/2020	

Generation DC Supplied System Update

GENERAL INFORMATION

Year	Current Approval	Requested Change	Proposed Total
2021	\$840,000	\$0	\$840,000
2022	\$900,000	\$0	\$900,000
2023	\$840,000	\$0	\$840,000
2024	\$900,000	\$0	\$900,000
2025	\$0	\$800,000	\$800,000

Requested Spend Time Period	yearly
Requesting Organization/Department	GPSS
Business Case Owner Sponsor	Glen Farmer Andy Vickers
Sponsor Organization/Department	GPSS
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

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

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

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

Some of the other issues we have had on the DC systems are the failing of battery cells due to inconsistent temperature and environmental control needed

Generation DC Supplied System Update

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

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

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

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.**

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

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

Generation DC Supplied System Update

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

The biggest risk is a battery bank not being able to provide load to the plant. The batteries are supposed to have a 20-year life based on the manufacture, but we have only seen one manufacture perform to this level. We are using this manufacture going forward and expect to have them last the full life.

If not approved and we have a failure of a battery then budgets, schedules and resources on other projects would be diverted to handle fixing the failure.

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.

With the DC design standard, we are creating the best possible environment for the battery banks and have enhanced monitoring of the system. This gives Operations better insight to how the DC system is functioning.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

The preparation of our DC Standard incorporates IEEE design parameters and standards. It has redundancy built in for testing and supplying load.

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
1. Address the DC systems as they fail testing or battery issues arise.	\$1,315,000/yr	01/2017	12/2030
2. Establish an independent DC system replacement program to bring plants to a standard as quickly as possible.	\$1,315,000/yr	05/2027	8/2026

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

The capital request was developed from budgetary quotes from manufacture and compared to previous projects of similar type.

Generation DC Supplied System Update

- 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.**

There are normally three different projects happening each year. One project would be in the initiation phase, the next would be in the execution phase and the next would be in the close out phase. Maintenance is reduced after the execution phase and we have not seen it pick back up for the first five years of the life span.

- 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 engineer business process would be used. This allows for the stakeholders to be involved from the beginning to the end of the project.

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

The risk of addressing the DC system when there is an issue is usually that is too late. We have had one instance where the DC system failed and some equipment was damaged due to this not functioning correctly.

- 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.**

We normally have one project per year become used and useful.

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

A new DC System contributes to the Safe and responsible design, construction, operation and maintenance of Avista's generation fleet.

- 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 prudence will be reviewed and re-evaluated throughout the project**

We ranked this project based on a ranking matrix to ensure prudent consideration of costs, scheduling and personnel resources.

- 2.8 Supplemental Information**

Generation DC Supplied System Update

2.8.1 Identify customers and stakeholders that interface with the business case

Electric shop, Relay shop, Engineering, Operations, Protection, Environmental, Project Management and Power Supply.

2.8.2 Identify any related Business Cases

None

3.1 Steering Committee or Advisory Group Information

The Steering Committee consists of the following members: Manager of Project Delivery, Manager of Maintenance and Construction, Manager of Hydro Operations & Maintenance.

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

Persons providing oversight include: Generation Electrical Engineering Manager, Forman PCM shop, Manager C&M - Electric Shop and the Plant Managers.

The undersigned acknowledge they have reviewed the Generation DC Supplied System Update 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 S. Farmer Date: 8/1/2020

Print Name: Glen Farmer

Title: Generation Electrical Engineering Manager

Role: Business Case Owner

Signature: *Andrew Vickers* Date: 8/3/2020

Print Name: Andy Vickers

Title: Director, GPSS

Role: Business Case Sponsor

Signature: _____ Date: _____

Print Name: Bob Weisbeck

Generation DC Supplied System Update

Title: _____
Manager, Hydro Operations and
Maintenance

Role: _____
Steering/Advisory Committee Review

Template Version: 05/28/2020

HMI Control Software

EXECUTIVE SUMMARY

The HMI Control Software update is a 10 (ten) million-dollar, multi-year effort to transition the controls software at all GPSS generating facilities from Wonderware to Ignition. This transition is integral to the continued safe and reliable operation of our generating units.

As a part of this updated, supporting software and hardware will also need to be upgraded as to ensure communication and support across all parts of our controls system. The timing of this transition is critical due to the expiring support for both Wonderware and Windows 7 (the current, and only, operating system functional with Wonderware). Risk likelihood, exposure, and severity increase the longer we continue to operate on extended service agreements and unsupported technology.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	<i>Kit Parker</i>	<i>Initial draft of original business case</i>	<i>7.10.17</i>	<i>Signed/approved</i>
1.1	<i>Kara Heatherly</i>	<i>Conversion to new format</i>	<i>6.20.20</i>	<i>Includes budget update</i>
1.2	<i>Kara Heatherly</i>	<i>Update for current budget projections and new schedule</i>	<i>7.9.21</i>	

HMI Control Software

GENERAL INFORMATION

Requested Spend Amount	(5 Year - \$7,600,000) (Full Program (\$10,400,000))
Requested Spend Time Period	5 years
Requesting Organization/Department	GPSS
Business Case Owner Sponsor	Jeremy Winkle Andy Vickers
Sponsor Organization/Department	GPSS
Phase	Execution
Category	Project
Driver	Asset Condition

HMI Control Software

1. BUSINESS PROBLEM

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

The existing Human Machine Interface (HMI) software, Wonderware has reached end of life as support ended in 2017. HMI Control Software is used to develop control screens which are used to control generating systems within Avista Hydroelectric Developments and Thermal Generating facilities. They allow an operator to run the station from a computer in a control room rather than from the equipment on the generating floor. New control screens need to be developed using a new software platform. The major driver for the HMI Control Software business case is the Asset Condition. This project aligns with Avista's Safe & Reliable Infrastructure strategy.

The existing architecture is outdated and requires software to be run on each individual computer. Moving to a new HMI platform will require moving to a server-based architecture.

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

Asset Condition: New HMI control software is needed now to prevent limitations going forward that will introduce security risks. The existing HMI software runs on Windows 7, which is planned to be unsupported after 2020.

Developing new controls screens on a new software platform will modernize control screens and allow operators to carry out their responsibilities more effectively. Control Screen will need to be developed for each generating facility; therefore, a planned approach will allow engineering and technicians to develop screens over time to coordinate with control upgrades.

In addition, a new server-based architecture will also create efficiencies for technicians as they will be able to maintain and update screens remotely.

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

If we do not stay current with supporting operating systems, then cyber security risks increase. Additionally, continuing operations on unsupported equipment puts our facilities at an increased risk of technology failure with much longer repair durations and continually increasing costs for support.

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 project execution team (co-led by GPSS and ET PM resources) has established a draft implementation schedule which addresses the following high-level deliverables:

- Develop design standards and validate ET implementation plan – Summer 2021
- Complete GCC PLC Lab (Summer 2021) and Monroe Implementation (new projected ET completion date: Spring 2022) to provide GPSS and ET opportunities to test screen design and practice conversions in order to minimize impact to generating facilities and outage durations during site installations

HMI Control Software

Option	Capital Cost	Start	Complete
<i>Purchase new software platform and develop new control screens</i>	\$10,400,000	1/2018	12/2024
<i>Upgrade existing software (Wonderware) and develop new control screens</i>	\$1,000,000	1/2018	9/2021
<i>Do nothing</i>	\$0		

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

The preferred alternative is to purchase new HMI control software that better meets the need of operators, protection control and meter (PCM) technicians, and engineers. Most HMI control software provides the same functionality but engineers and PCM technicians are interested in software that provides user-friendly installations, interfaces with existing equipment with ease, such as PLCs, and allows for control screen modifications and troubleshooting with efficiency.

This alternative addresses concerns with unsupported software, such as cyber security vulnerabilities. There is a risk that upgrading HMI software and developing new screens will take longer than expected. The duration of the project could take longer due to complexity, limited outage availability, or a shortage of resources. To mitigate risk a project manager is needed to maintain schedule and provide ongoing coordination. A Controls Engineer is also needed to consistently upgrade control screens at each generating facility. Engineering will assist with developing a new server-based architecture and developing and commissioning HMI control screens, as well as designing upgrades for the supporting plant infrastructure (namely PLC's.) The PCM Shop will need at least one full time resource to develop, install and commission the new HMI control screens. A contractor will be necessary, at least in the beginning, to help establish a new control screen standard template. Support from the Enterprise Technology (ET) will also be necessary to install new servers at each plant and provide ongoing support.

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 are in accordance with the 5-year CPG budget table below.

Year	Requested Amount
<i>Prior</i>	\$3,113,938
<i>2022</i>	\$4,000,000
<i>2023</i>	\$2,600,000
<i>2024</i>	\$1,000,000
<i>2025</i>	\$0

HMI Control Software

2026	\$0
------	-----

It is expected that a server-based architecture will reduce O&M costs as it will allow for modifications to be made to HMI control screens from one central location and eliminate the need to drive to each facility when changes are required. However, the servers will require ongoing support, therefore increasing O&M costs. Eliminating the extended Windows 7 support contract will also reduce O&M costs.

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 successful implementation of this new control software will improve remote monitoring and controls at all our facilities, secure and protect Avista's critical infrastructure, and minimize the impact of future technology upgrades and versioning on plant operations.

Bringing this system up to date will also ensure continued support from ET Applications, software licensing and versioning, as well as visibility into potential network and version conflicts. The Ignition design will also provide our PCM techs with real-time support from Controls Engineering by providing read-only access to the plant control screens from the Mission campus.

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

The alternatives considered (also represented in the table at the beginning of Section 2) ranged from inaction to complete product replacement. The selection of complete replacement was made based upon the risk/reward analysis performed at the onset of the project. Maintaining the Wonderware product still posed a near-term risk to operations by continuing a relationship with an antiquated and unsupported product. The decision to procure and design an entirely new solution better positions Avista for the future and mitigates more of the long-term risks associated with sunseting technologies.

HMI Control Software

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.

Site conversion will begin in 2020 and continue in accordance with the table attached, these dates reflect anticipated completion dates and therefore also represent the anticipated schedule for transfers to plant.

Facility	Conversion Year
GCC – PLC Lab	2021
GCC – Full Facility	2022
Monroe	2022 – potential short term test solution for 2021
Nine Mile	2022
Rathdrum	2022
Upper Falls/Control Works	2022
Long Lake	2022
Little Falls	2022
Cabinet Gorge	2023
Noxon	2023
Northeast	2023
Boulder Park	2023
Post Falls	2024
Post Street	2024 – pending prioritization shift

HMI Control Software

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 direct impacts to services. This innovative approach allows us to pilot software updates and configurations before implementing on active sites. This in turn, shortens our outage time and allows our operations team to reserve capacity for other critical needs.

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 prudence will be reviewed and re-evaluated throughout the project

One way to evaluate prudence is to consider not only the likelihood of risk but the severity of the outcome in the event of failure. Currently, failure of the controls system at our generating facilities would be nearly immediately catastrophic. Especially at remote facilities where resources are not physically available to bring systems online and facilities are not staffed to assume fully manual operations, having a central system “brain” for these functions is essential to keeping the system online and, if necessary, getting the system back online quickly. Minimizing the severity of non-preventable failure is the prudent and responsible thing to do.

Additionally, operating systems that are no longer supported on extended maintenance agreements is not sustainable, responsible, or cost effective, and exposes the plants to unnecessary risk.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholders that interface with the HMI Control Software Business Case include:

- Controls Engineering
- Project Management
- Hydro Operations
- Thermal Operations
- PCM Shop
- ET (Central, Distributed, Network, Security, and Applications)

HMI Control Software

2.8.2 Identify any related Business Cases

SCCM (09805992) – System Center Configuration Manager (SCCM) must be deployed to all GPSS production sites prior to the implementation of HMI. SCCM is the vehicle used to distribute the application to the site and to be able to manage updates and patches remotely from the GCC.

Win10 (09906389) - To the degree that the Windows 10 implementation is delayed out past HMI's current implementation schedule, those costs could become the burden of the HMI project or could equivalently impact the HMI installation schedule.

3.1 Steering Committee or Advisory Group Information

The need to address the risk of aging control software and outage control screens has been vetted through the Generation Production and Substation Support (GPSS) planning process.

The Controls Engineering Manager, along with the assigned Project Manager, will provide oversight and monthly tracking of the ongoing work within the project.

The Joint ET/GPSS Steering Committee will be comprised of the following members: GPSS Hydro Operations Manager (Bob Weisbeck), GPSS Thermal Operations Manager (Thomas Dempsey), GPSS Construction and Maintenance Manager (Alexis Alexander), GPSS Manager of Project Delivery (Jacob Reidt), ET Manager of Systems Engineering (Walter Roys), ET Manager of Applications Delivery (Brian Hoerner), ET Manager of Network Engineering (Shawna Kiesbuy)

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

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. At this point, we know that an ET and a GPSS PM will work in tandem to schedule, budget, and allocate resources appropriately to meet the project execution goals.

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 joint ET/GPSS Steering Committee when and if determined to be necessary. 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:

Date:

7/9/2021

HMI Control Software

Print Name: _____

Jeremy Winkle

Title: _____

Controls/Electrical
 Engineering Manager

Role: _____

Business Case Owner

Signature: _____



Date: _____

7/8/2021

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

Hydro Safety

EXECUTIVE SUMMARY

Through 18 CFR Section 12.42, the Federal Energy Regulatory Commission (FERC) is given broad regulatory discretion over the installation, operation and maintenance of hydro public safety device near Avista's dam. In addition to regulator requirements for such device such as lights, sirens, signage and barriers, Avista is subject to potential liability should the company not maintain safety-related equipment. Projects are identified in a variety of ways, including physical condition/age/function, changing standards in FERC guidance, industry practice, or emergent public safety needs. All projects are subject to conceptual approval by the Chief Dam Safety Engineer and to additional internal review and oversight. Work is both planned and opportunistic, leveraging scheduled outages. The program cost has historically been approved at \$50,000 annually.

This work benefits customers by maintaining and enhancing safety, ensuring compliance, and reducing risk. Customers impacted include all electric customers in Washington and Idaho (service code and jurisdiction ED/AN). If this business case is not approved, operating costs would increase as Avista would still maintain safety-related equipment to remain in compliance. In the absence of funding, Avista would undertake increased risk by delaying the purchase and installation of equipment.

VERSION HISTORY

Version	Author	Description	Date	Notes
<i>Draft</i>	<i>Michele Drake</i>	<i>Initial draft of original business case</i>	<i>6/29/2020</i>	
<i>1.0</i>	<i>Michele Drake</i>	<i>Completed business case</i>	<i>7/27/2020</i>	
<i>1.1</i>				

Hydro Safety

GENERAL INFORMATION

Requested Spend Amount	\$50,000
Requested Spend Time Period	<i>Annual</i>
Requesting Organization/Department	H04 / Hydro Safety
Business Case Owner Sponsor	Michele Drake Bruce Howard
Sponsor Organization/Department	A04 / Environmental Affairs
Phase	Execution
Category	Program
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

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

Avista has an ongoing need to maintain existing hydro public safety measures and to address any emergent hydro public safety needs.

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

This business case is driven by the need to meet overall hydro public safety compliance requirements and by asset condition. Benefits to the customer include risk and liability reduction for the company, the presence of measures that improve overall safety for the recreating public.

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

Failing to maintain or deferring maintenance of existing hydro public safety measures or a failure to respond to emerging issues places Avista at risk for liability and non-compliance penalties. 18 CFR Part 12 delegates the authority to require safety devices at dams, where necessary to the FERC's Regional Engineer. Section 12.42 of the Regulations state that, "To the satisfaction of, and within a time specified by the Regional Engineer, an applicant or licensee must install, operate, and maintain any signs, lights, sirens, barriers, or other safety devices that may reasonably be necessary or desirable to warn the public of fluctuations in flow from the project or otherwise, to protect the public in the use of the project lands and waters." The FERC performs annual physical inspections of our dams, noting any items that need attention. Measures that require replacement are also identified by operators and hydro public safety staff.

Hydro Safety

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

A lack of directive hydro public safety related follow-up items from annual FERC inspections and the timely replacement of equipment are indicators of success.

1.4 Supplemental Information

1.4.1 Please reference and summarize any studies that support the problem

N/A

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

N/A

Option	Capital Cost	Start	Complete
<i>Capital funding</i>	\$50,000	01 2021	12 2022
<i>Activity continues – O&M budget overage</i>	\$0	01 2021	12 2021

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

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

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.

Safety items are an on-going process to ensure public safety. Hydro Safety is mandatory and will result in an O&M expenses if capital dollars are not properly allocated, or in the worst case, increased risk and liability should projects not be carried out.

Hydro Safety

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

This business case involves the hydro public safety business function, impacting the Dam Safety Team from GPSS and Environmental Affairs. Successful implementation may include staff work by engineering/design, procurement, plant management, operations staff and shop crews.

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

Alternatives and possible mitigation strategies are considered on a case-by-case basis, for each proposed measure.

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 timeline depends on the measures targeted for replacement.

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

Hydro public safety efforts align with Avista's focus on safety within our business, reliable energy, and overall stewardship.

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 prudence will be reviewed and re-evaluated throughout the project

N/A

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

Stakeholders, who may interface with the business case, include members of the Dam Safety Team from GPSS and Environmental Affairs. Customers include the FERC (regulator) and the recreating public.

2.8.2 Identify any related Business Cases

N/A

3.1 Steering Committee or Advisory Group Information

All projects will be vetted by the Chief Dam Safety Engineer, hydro safety staff, the appropriate hydro operator and the appropriate plant manager. If a large-scale measure requires replacement, a formal project plan, including a steering committee, may be deemed appropriate.

Hydro Safety

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

This will be identified on a case-by-case basis, depending on the complexity and scale of the proposed measure.

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

This will be identified on a case-by-case basis, depending on the complexity and scale of the proposed measure.

The undersigned acknowledge they have reviewed the [Hydro Safety](#) 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:	<i>Michele Drake</i>	Date:	7/28/2020
Print Name:	Michele Drake		
Title:	Supervisor, Hydro Compliance Services		
Role:	Business Case Owner		
Signature:	<i>Bruce Howard</i>	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

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 generating 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

Little Falls Plant Upgrade

1. BUSINESS PROBLEM

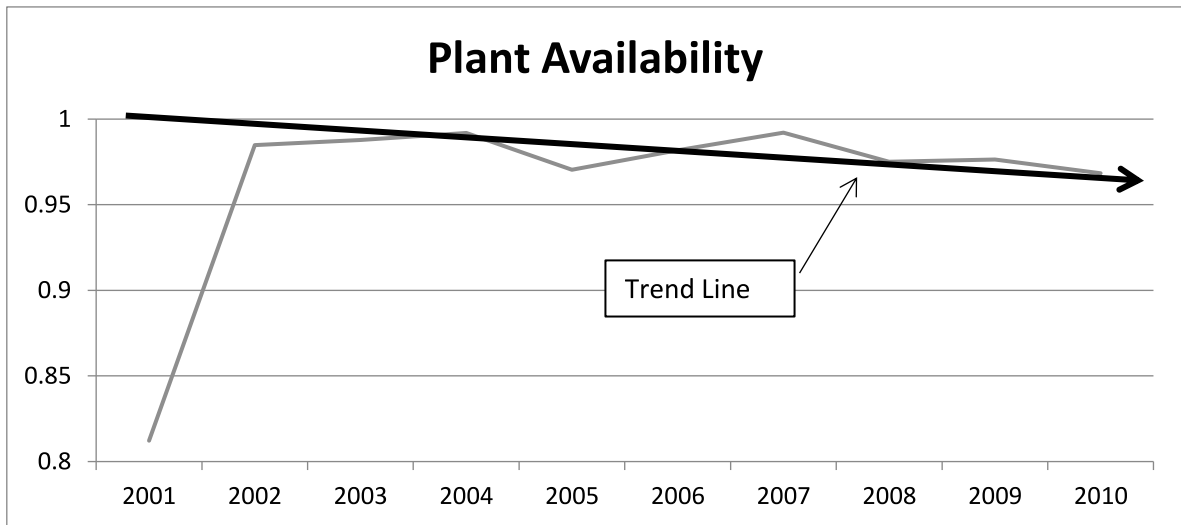
1.1 What is the current or potential problem that is being addressed?

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
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Little Falls Plant Upgrade

<i>Alternative 3: Preferred</i>	\$56,100,000	\$0	2012	2021
<i>Status Quo</i>	\$0	\$150,000/yr		
<i>Alternative 1</i>	\$5,000,000	\$20,000/yr		
<i>Alternative 2</i>	\$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 <i>(Admin use only)</i>
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 seamless 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

Little Falls Plant Upgrade

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
<u>2019</u>	<u>\$13,000,000</u>
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, responsibly 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 Infrastructure, 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 prudence will be reviewed and re-evaluated throughout the project

Prudence 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 systems 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.

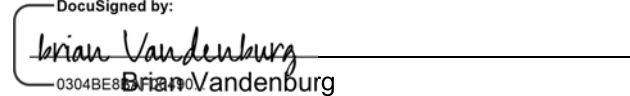
The Project Steering Committee oversees the deliverables of the individual projects. Each member of the steering committee represents a major stakeholder in the project. The members are dependent on the respective project but will include representatives from hydro operations, central shops and engineering. 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.

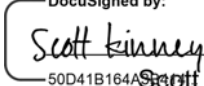
The undersigned acknowledge they have reviewed the HMI Control Software Business Case and agree with the approach it presents. Significant changes to this will be coordinated with and approved by the undersigned or their designated representatives.

Signature:  Date: Jul-10-2020 | 8:14 AM PDT
 Print Name: Brian Vandenburg
 Title: Manager, Hydro Operations
 Role: Business Case Owner

Signature:  Date: Jul-10-2020 | 8:30 AM PDT

Little Falls Plant Upgrade

Print Name: _____
 Title: _____
 Role: _____

Signature:  _____ Date: Jul-13-2020 | 5:56 AM PDT
 Print Name: 50D41B164A83401 Scott Kinney _____
 Title: _____
 Role: _____

Template Version: 05/28/2020

Long Lake Plant Upgrade Program

EXECUTIVE SUMMARY

The existing Long Lake equipment ranges in age from 20 to more than 100 years old. We have experienced an increase in forced outages at Long Lake over the past six years, almost zero in 2011 and increasing every year since then. This is caused by equipment failures on a number of different pieces of equipment. Long Lake serves Avista's allocated north electric district providing power to our transmission grid and local distribution power sources. The primary drivers for the Long Lake Plant Upgrade are Performance & Capacity, Asset Condition, and Failed Plant & Operations. Four alternatives were considered for solutions to replacing the aged and failing equipment; (1) Install four new 30MW vertical units, (2) Construct a new one-unit powerhouse, (3) Construct a new two-unit powerhouse, and (4) Alternative 4 and the recommended alternative, replace the existing units in kind. An anticipated program budget of \$60.5M has been developed from a Class 4 Estimate.

Upgrading our Long Lake Plant will enable our generation fleet to continue to provide safe and reliable power to our customers. If not approved, The Long Lake powerhouse would continue to operate as it has for the past 10 years. O&M costs would continue to rise. In an additional 10 years, if the trend continues, average O&M costs will rise from \$285k in 2005 to \$590 in 2014 and projected to be \$900k in 2024. Due to the condition of the generators, it is likely that one of the generators or another piece of major equipment will fail and permanently disable equipment, increasing forced outage numbers.

Specifically, the turbines are thrusting too much (a sign of significant wear), including a failure in 2015. The 1990 vintage control system is failing and only secondary markets can support this equipment. Inspections of other components of the generator show the stator core is "wavy". The core lamination steel should be in straight. The "wave" pattern is a strong indication of higher than expected losses are occurring in the generator.

With the increase in generator output, the output of the generator step up transformer (GSU) has also increased to its rating. GSU's are more than 30 years old and operating at the high end of their design temperature, these are now approaching their end of useful life and need to be replaced proactively rather than wait for a failure. The other major drivers for the program is Station Service disconnect switching safety.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Brian Vandenburg	Initial approved original business case	3/22/2017	Signed 4/19/17
1.1	Michael Truex	Updated Business Case	6/19/2020	Updated with BC Refresh
1.2	Michael Truex	Updated BC with greater detail	7/31/2020	Added content

Long Lake Plant Upgrade Program

GENERAL INFORMATION

Requested Spend Amount	\$60,500,000
Requested Spend Time Period	2009 - 2026
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner Sponsor	Brian Vandenburg Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Phase	Execution
Category	Program
Driver	Asset Condition

1. BUSINESS PROBLEM

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

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

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

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

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

With the increase in generator output, the output of the generator step up transformer (GSU) has also increased to its rating. These GSU's are now running at the high 65C temperature

Long Lake Plant Upgrade Program

which is a concern. As these GSU's are more than 30 years old and operating at the high end of their design temperature, these are now approaching their end of useful life and need to be replaced proactively rather than wait for a failure.

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

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**

The Long Lake Plant Upgrade addresses multiple drivers; Service Quality & Reliability, Performance & Capacity, aged assets, and failing plant with operational impacts. It is important for our customers that our generating units are both available and reliable. It is also prudent that Avista maintain personnel safety for employees working at the plant.

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

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

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 LLPU project team will be utilizing data from GPSS asset condition information, trending plant data, as well as, using third party engineering experts to assist in alternative analysis, and engineering recommendations for upgrades. Third party studies have helped identify large scale options for the plant upgrade, and internal Avista engineering in partnership with third party consultants have added additional alternatives for consideration. Alternative analysis options are considering upfront costs, construction costs, life cycle costs, return of investment, and sustained maintenance costs, along with future capacity options.

Long Lake Plant Upgrade Program

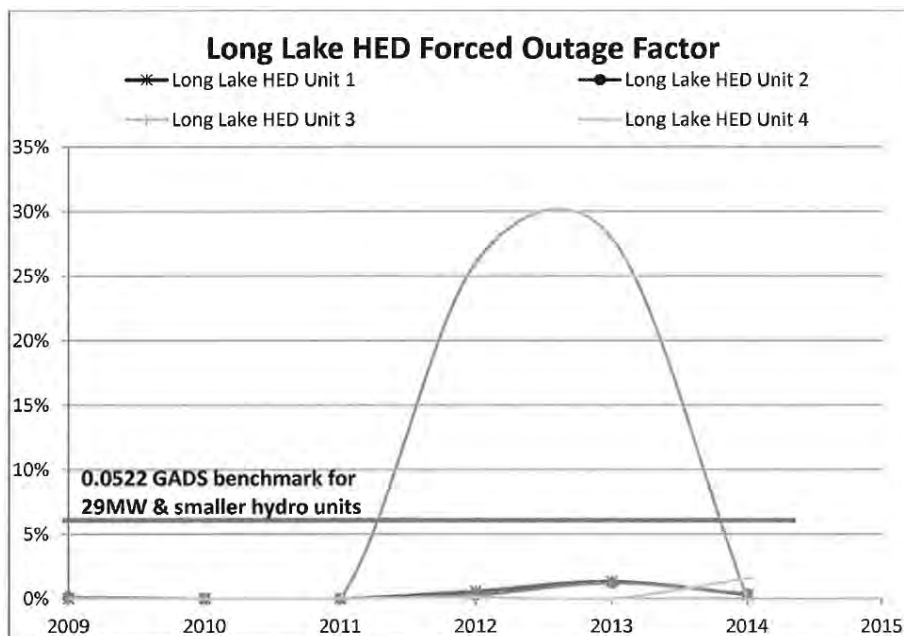
1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

- Summary of Investment Considerations for Long Lake Modernization Program
- Spokane River Assessment (Oct 2014) Phase II Reconnaissance Study – Long Lake HED – URS
- Long Lake Dam Generator Voltage Study & Life Cycle Analysis (June 2020) - Stantec

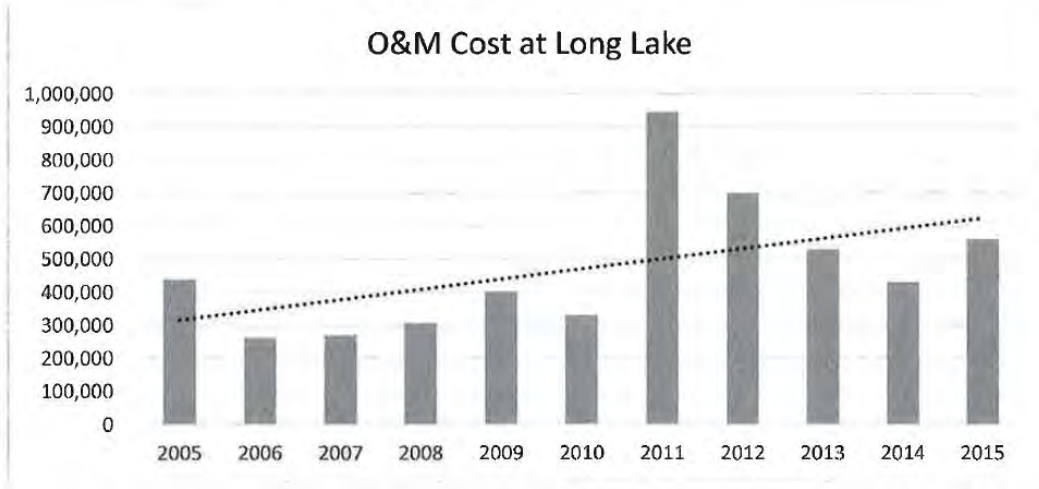
1.5.2 For asset replacement, include graphical or narrative representation of metrics associated with the current condition of the asset that is proposed for replacement.

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



The below graph shows the O&M cost at Long Lake for years 2005 - 2015. The trendline is increasing due to increasing repairs to aging equipment.

Long Lake Plant Upgrade Program



Long Lake Plant Upgrade

Alternative 4 and Recommended Alternative: Replace Units In-Kind would replace the existing major unit equipment (generator, field poles, governors, exciters, generator breakers) with new equipment.

Option	Capital Cost	Start	Complete
<i>Alternative 1: Install four new 30MW vertical units</i>	<i>\$173M</i>	<i>05 2018</i>	<i>06 2030</i>
<i>Alternative 2: Construct one unit powerhouse</i>	<i>\$144M</i>	<i>05 2018</i>	<i>06 2035</i>
<i>Alternative 3: Construct two unit powerhouse</i>	<i>\$276M</i>	<i>05 2018</i>	<i>06 2035</i>
<i>Alternative 4 and Recommended Alternative: Replace units in-kind</i>	<i>\$60.5M</i>	<i>05 2018</i>	<i>03 2027</i>

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

Relevant data is comprised of Long Lake HED historical data, maintenance logs, asset condition, third party analysis, and lessons learned from similar work performed at Little Falls HED.

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.

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

LONG LAKE PROGRAM REVISED BUDGET - 2021 (5yr CPG)								
Project #	Description	2021	2022	2023	2024	2025	Totals	Project Level
20305098	Bridge Crane						\$ 2,735,312	Level 2
20305099	Station Service Upgrade	\$ 668,606	\$ 2,696,703				\$ 4,836,827	Level 2
20305122	Network Upgrades	\$ 85,000	\$ 62,000	\$ 50,000	\$ 50,000	\$ 50,000	\$ 372,739	Level 1
20305105	Access Road Repaving						\$ 1,206,000	Level 1
20305106	Sewer System Upgrade						\$ 205,000	Level 1
20305123	Facility Upgrades						\$ 559,594	Level 1
20305139	Flood Mitigation	\$ 1,000,000					\$ 1,380,000	Level 2
20305121	Unit 1 Upgrade	\$ 2,036,452	\$ 1,491,902	\$ 5,300,292	\$ 122,373		\$ 10,391,235	Level 2
	Unit 2 Upgrade		\$ 1,866,747	\$ 2,036,452	\$ 1,491,902	\$ 5,300,292	\$ 10,695,393	Level 2
	Unit 3 Upgrade			\$ 1,066,747	\$ 2,867,576	\$ 3,828,000	\$ 7,762,323	Level 2
	Unit 4 Upgrade				\$ 3,866,747	\$ 2,367,576	\$ 6,234,323	Level 2
	PLC Sump Upgrade		\$ 350,000				\$ 350,000	Level 1
	Control Room Upgrade		\$ 350,000	\$ 250,000	\$ 250,000	\$ 400,000	\$ 1,250,000	Level 1
	Substation	\$ 450,000	\$ 3,700,000	\$ 2,000,000	\$ 2,000,000		\$ 8,150,000	Level 3
	Engr & Design Support	\$ 412,183	\$ 1,012,183	\$ 1,012,183	\$ 1,012,183	\$ 1,012,183	\$ 4,460,915	
	Totals	\$ 4,652,241	\$11,529,536	\$11,715,674	\$ 11,660,781	\$ 12,958,051	\$ 60,589,662	
	CPG Request	\$ 4,500,000	\$11,500,000	\$11,500,000	\$ 11,500,000	\$ 12,500,000		

Long Lake Plant Upgrade

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 respective projects teams are working with many other business units and very high level of coordination will be ongoing throughout the life of LLPU. Representative business units are as follows, but not limited to; Substation, Transmission, Protection, System Operations, Power Supply, Supply Chain, Environmental & Permitting, Dam Safety, GPSS Engineering, GPSS Project Delivery, GPSS Shops, Corporate Communications, Facilities, Distribution Operations, State and Local Agencies, and external contractors and engineering consultants. There will undoubtedly be impacts to operations, system operations, environmental, power supply, and others previously mentioned throughout several phased of project implementation.

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

Alternative 1: Install four new 30MW vertical units

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

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

Alternative 2: Construct one unit powerhouse

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

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

Alternative 3: Construct two unit powerhouse

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

Long Lake Plant Upgrade

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

Alternative 4 and Recommended Alternative: Replace units in-kind

This alternative would replace the existing major unit equipment (generator, field poles, governors, exciters, generator breakers) with new equipment. Within this option, there are 10 options regarding GSU configuration, Bus configuration, and Generator Voltage.

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.

May 2017 – Project Kickoff

September 2018 – Bridge Crane Replacement - Complete

September 2018 – Sewer System Overhaul - Complete

September 2018 – Access Road Overhaul - Complete

January 2020 – Facilities Upgrades Phase 1 - Complete

December 2021 - Station Service Replacement Commissioned

January 2023 – PLC Sump Upgrade

October 2023 – GSU Upgrade Phase 1

December 2023 – First Unit Upgrade

December 2024 – Second Unit Upgrade

October 2025 – GSU Upgrade Phase 2

December 2025 – Third Unit Upgrade

February 2026 – Facilities Upgrade Phase 2

December 2026 – Fourth Unit Upgrade

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

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

Long Lake Plant Upgrade

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 prudence will be reviewed and re-evaluated throughout the project

The project budget and total cost will be regularly reviewed with the project steering committee, as well as, receive approvals as described below for any changes in scope and cost. Prudence is also measured by remaining in compliance the FERC License such that we can continue to operate Spokane River 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

- Program Steering Committee:
 - Andy Vickers – GPSS Director
 - Bruce Howard – Sr. Director Environmental Affairs
 - Scott Kinney – Director Power Supply
- Respective Project Steering Committee Members:
 - Jacob Reidt – Project Delivery Manager
 - Bob Weisbeck – Manager Hydro Operations & Maintenance
 - Alexis Alexander – Manager Maintenance Management & Construction
 - Meghan Lunney – Manager Spokane River License
- Project Sponsor: Andy Vickers – GPSS Director
- Budget Owner: Brian Vandenburg – Lower Spokane River Manager
- Program Manager: Michael Truex – Long Lake Program Manager
- Project Manager: Various
- Internal Project Stakeholders:
 - Asset Management: Robert Gray (Sr Eng II)
 - AVA Construction: Brad McNamara (Electric Shop GF), Jeff Vogel (Relay Shop GF), Randy Pierce (Mechanic Shop GF)
 - Engineering Roundtable: Lamont Miles (Sr Engineering I-Project Manager)
 - Enterprise Assets: Jennifer Lund (Manager)
 - External Communications: Jae Ham (Comm Spec II)
 - GPSS Engineering Managers: PJ Henscheid (Civil), PJ Henscheid (Mechanical), Kristina Newhouse (Controls), Glen Farmer (Electrical)
 - GPSS Engineers: Eric Atkinson (Electric Contractor Crew Inspector)
 - Hydro Compliance: Michelle Drake (Supervisor Hydro Compliance)
 - Power Supply: Pat Maher (Sr Hydro Op Eng II), Steve Lentini (Sr Hydro Op Eng II)
 - Project Management: Michael Lang (Product Owner)
 - Program & Project Delivery: Elizabeth Arnold (IT Program Manager)

Long Lake Plant Upgrade

- Relay & Protection Design: Randy Spacek (Mgr Engineering Protection), Kevin Damron (Sr Eng I)
- Safety & Craft Training: Clint Sharp (Safety and Health Specialist)
- SCADA: Garth Brandon (Chief Systems Operator)
- Spokane River - Hydro: Brian Vandeburg (Lower Spokane River Mgr), Kevin Powell (Long Lake Chief Operator), Craig Bourassa (Sr Plant Engineer)
- Spokane River License: Meghan Lunney (Mgr Spokane River License), Robin Bekkedahl (Sr Enviro Scientist), Rene' Wiley (Env Spec Scientist III)
- Substation Design: Glenn Madden (Mgr Engr Substations)
- Supply Chain Management: Cody Krogh (Mgr Supply Chain), Karen Carter (Sr Sourcing Professional), Shelly Campbell (Sr Sourcing Professional)
- Transmission Design: Mike Magruder (Director T&D System Ops, Transmission), Ken Sweigart (Mgr Engr)
- Utility Accounting: Bill Abrahamse (Sr Unitization Accountant)
- Core Project Team:
 - Avista Engineering: Tracy West (Mechanical), Rob Selby (Electrical), Paul Lennemann (Civil), Jeremy Fauth (Controls), Nick Agostinelli (Mechanical)
 - Avista Construction Foremen: Jeremy Hostetler (Electrical), Chuck Parker (Mechanical), TBD (Relay)

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.

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

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

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

Long Lake Plant Upgrade

Each respective project within the LLPU will have additional steering committees and meet at their own cadence.

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

Generally decision-making, and prioritization will be done through Steering Committee and GPSS Department SCRUM. Projects will utilize the Project Change Log to track and manage all Project Change Requests (PCR) associated with the delivery of the construction project. The PCR describes the need for change, supplemental documentation, related project artifacts, change order proposals, and any other pertinent information. PCR's are then signed for approval by the project approval thresholds, and then processed against the project risk registry, and or contract amendment with the contractor.

The undersigned acknowledge they have reviewed the [Long Lake Plant Upgrade](#) 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:	<i>Brian Vandenburg</i>		Date:	7/31/2020
Print Name:	Brian Vandenburg			
Title:	Lower Spokane River Manager			
Role:	Business Case Owner			

Signature:	<i>Andrew Vickers</i>		Date:	7/31/2020
Print Name:	Andy Vickers			
Title:	Director GPSS			
Role:	Business Case Sponsor			

Template Version: 05/28/2020

Peaking Generation

EXECUTIVE SUMMARY

Avista's Peaking Generation plants offer operational flexibility and are utilized to support energy supply needs. Thermal Peaking Generation power provides options for Avista's System Operations and Power Supply groups to maximize value to Avista and its customers. These plants represent more than 255 MW of power and include Rathdrum Combustion Turbines, Boulder Park Generating Station and Northeast Combustion Turbine, all natural gas fired power plants.

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, replacement of equipment at their end of life, and small capital upgrades to plant facilities. The business drivers for this projects in this program is a combination of Asset Condition, Failed 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.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Mike Mecham	Initial draft of original business case	7/8/2020	
1.0	Mike Mecham	Peaking Generation Business Case	6/22/2021	for 2022 - 2026

Peaking Generation

GENERAL INFORMATION

Requested Spend Amount	\$2,300,000
Requested Spend Time Period	5 years 2022 through 2026
Requesting Organization/Department	T07 / 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?

Due to the age and use of the peaking thermal generation facilities, some core 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 generating facilities. This program is critical in providing funding to support the replacement of core assets and systems that support the reliable operations of these 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 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.

Asset age, hours of use 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 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.

Peaking Generation

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.

Thermal Plants utilize plant reliability and availability metrics as well as in use hours to determine some of the projects. Historically, this program has funded multiple projects per year which contributed to unit availability and ensure reliability by completing hours based capital replacement or upgrades to equipment.

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, used hours replacement of equipment, and Failed Plant. Projects are typically completed in the calendar year. The work is primarily performed in the 2rd and 4th quarters of the year when outage in the Peaking Thermal Plants are scheduled, typically during run off in the river systems or during milder weather conditions when power prices are low and it is most opportune to have the plants unavailable for projects.

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 that consists of Thermal Management, Maintenance Engineering and Plant Personnel.

Option	Capital Cost	Start	Complete
Peaking Generation Program	\$2,300,000	01/2022	12/2026
Individual Capital Projects	\$2,250,000	01/2022	12/2026
Perform O&M maintenance	0		

Peaking Generation

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 the a realistic annual budget is \$500,000. In order to support the capital budget goals of the GPSS department, this budget was reduced in the short term for years 2022 through 2026 by 10%. Projects with lower risk will be delayed through this period.

The drivers of the projects selected to be funded by this program are mix of use hours based replacement, Asset Condition and Failed Plant. 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 projects in this program typically take place during the outages which are in the late spring and fall of each year. Most of the capital is deployed in the 2rd 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.

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 Thermal personnel, including Management and engineering. All of these projects are prioritized and coordinated by the broader support team.

Peaking Generation

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 5 to 10 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 Thermal Group. These projects are specific to these plants and the leadership in the Thermal Group understand best the nature and context of these projects.

These projects are, at times, 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 Peaking Thermal Plants, which are typically in the spring and fall of each year. Some projects may have the ability to be performed during non-outage times.

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 to small to medium size projects with the objective of keeping our Peaking Generation plants reliable and available to support the power needs of our company and our customers affordably. By doing this we support our mission of improving our customer's lives through innovative energy solutions which includes Peaking Thermal generation. By executing the projects funded by the program, we insure that Peaking Generation Facilities are performing at a high level and serving our customers with affordable and reliable energy.

Peaking Generation

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 prudence will be reviewed and re-evaluated throughout the project

Review of the program budget has revealed that a realistic annual budget is \$500,000. The 5 year historical average spend in the Peaking Generation Program is \$460,000. In order to support the capital budget goals of the GPSS department, this budget was reduced in the short term for years 2022 through 2026 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 and Failed Plant. 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

None

3.1 Advisory Group Information

The Advisory Group for this program consists of the Thermal Plant Operations Manager, Thermal Maintenance Engineering and the Manager of Thermal Operations and Maintenance.

Peaking Generation

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, and Safety and Security. The projects are vetted by the Thermal Advisory Group. With the assistance of Operations, Construction and Maintenance and Engineering, projects are evaluated to determine available options, confirm prudence, 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 Thermal Operations Manager, 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 Peaking Generation 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 Peaking Generation Program business case and agree with the approach it presents. Significant

Peaking Generation

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

Signature:  Date: 7/6/2021
 Print Name: Thomas C Dempsey
 Title: Mgr Therm Operations & Maint
 Role: Business Case Owner

Signature:  Date: 7/6/2021
 Print Name: _____
 Title: _____
 Role: Business Case Sponsor

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

Template Version: 05/28/2020

Post Falls Landing and Crane Pad Development

EXECUTIVE SUMMARY

The property located adjacent to the North Channel of the Post Falls Hydroelectric Development (HED) is being developed by the City of Post Falls for public use as a recreational area. In connection with the purchase of the property, the City of Post Falls and Avista have agreed to develop the area in such a way that it could be utilized by Avista for staging a crane, barges and equipment for maintenance and construction in support of the Post Falls HED. The area would be joint use and when not needed by Avista, the area would be utilized by the City of Post Falls and the public for recreational purposes.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Bob Weisbeck	Initial executive summary	7/20/2020	
1.0	Bob Weisbeck	Final version approved	8/2/2020	

GENERAL INFORMATION

Requested Spend Amount	\$3,110,000
Requested Spend Time Period	1 year
Requesting Organization/Department	C07/GPSS
Business Case Owner Sponsor	Bob Weisbeck Andy Vickers
Sponsor Organization/Department	C07/GPSS
Phase	Execution
Category	Project
Driver	Asset Condition

Post Falls Landing and Crane Pad Development

1. BUSINESS PROBLEM

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

Staging heavy equipment for major work at the Post Falls HED is difficult due to the access and space constraints of the locations of spillways and the powerhouse on the Spokane River. Staging equipment at Post Falls Park, which is the likely area, near the plant, will disrupt the public use of the park and present safety hazards to the public. In addition, access to this area is limited due to the size and capacity of the bridges across the river. The proposed site of the landing greatly increases the access for cranes, barges and heavy equipment needed to support construction and maintenance of the plant.

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.

The business drivers for this project are Asset Condition and Failed Equipment. The Post Falls North Channel spillway is over 110 years old. There have been upgrades to the gates and repair of the spillway, but the structure has reached the end of its useful life and needs a major rehabilitation or replacement. This work is expected to begin in 2022.

In addition, Unit #6 has failed and since it has reached the end of its useful life, cannot be repaired. Replacing this unit individually would not be practical because auxiliary and critical plant systems need to also be replaced. A study was performed in 2016 and the recommendation is to perform an entire facility overhaul. These projects will require access for the transport and installation major components plant, involving barges and heavy equipment. The construction of this landing will greatly simplify the process of getting heavy equipment and materials to the Post Falls facilities.

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

The work related to Post Falls cannot be delayed much longer. The North Channel Spillway has reached the end of its useful life. The generating units are outdated and are at or near the end of their useful lives. Unit #6 has failed which is evidence that it is past time to rehabilitate this facility. The risk is that more and more of the units might fail and the operation of the spillway could become compromised. This could have serious repercussions with operating the plant and controlling the flow of the Spokane River and the elevation of Coeur d'Alene Lake. This could also result in violations of the Spokane River Licensing agreement which would present a serious risk to Avista. The construction of the landing will enable a more accessible staging area in support of this work, streamlining the staging of equipment and materials.

Post Falls Landing and Crane Pad Development

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.

In 2014 through 2015 the rehabilitation project for the South Channel of Post Falls took place. The project revealed the serious degradation of the concrete in the spillway and verification that the gate and gate structures were well past their useful life. This project required extensive use of heavy equipment and barges to successfully complete this project. The rehabilitation of the North Channel will be more extensive and will require increased amount of heavy equipment and barges. The landing will greatly increase the access to the area for this equipment and be less disruptive to public areas since the work and access will be straightforward and more easily isolated from the public access.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

The South Channel Spillway project can be used as a calibration for this project. The North Channel Project which planned for 2022 will require more heavy equipment and barge use than the South Channel. This landing will provide an effective approach to supporting this work.

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.

An assessment of the landing was performed in 2018 to understand better the feasibility and cost of creating this landing and associated recreational features. The architect's concept and estimate were used to determine the high-level scope and cost estimate of this project.

2.

Option	Capital Cost	Start	Complete
Design and Construction	\$3,110,000	01 2021	12 2021
	\$0		

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

A landscaping architect contractor was hired to create conceptual designs of the landing for review with the City of Post Falls (City) and Avista. A Memorandum of Understanding (MOU) was signed by the City and Avista to move forward

Post Falls Landing and Crane Pad Development

with purchasing the property and developing the area for joint use. The architects estimate for scope and cost were used as a basis for this capital request.

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.**

This project is expected to take two years. The first-year effort will be the assessment and the design of the landing and the associated recreational features. This work will be completed in 2020. The second year, 2021, will include the construction of the landing and recreational features. That budget is expected to be \$3,110,000.

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 business functions and/or processes will be impacted in order to implement this business case. If the landing is not constructed, the major construction projects will be adversely impacted because access to the plant for heavy equipment is currently limited.

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

The first alternative is to not move forward with construction of the landing. This will create challenges for getting heavy equipment and materials to the Post Falls facilities and spillways due to limited access and the current constraint of bridge size and capacity. This will significantly affect the timeline and cost of large projects at the powerhouse and spillways.

If Avista decides to not work with City to develop the property for joint use, the area will not be available for crane and barge access to the plant. In addition, the City may elect not to develop the property and lose the opportunity to have a valuable public area that would benefit our customers in Post Falls.

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 project is expected to take two years. The effort in the first year will be the assessment and the design of the landing and the associated recreational features. This work will be completed in 2020. The second year, 2021, will include the construction of the landing and recreational features. That budget is expected to be \$3,110,000. The project is expected to become used and useful in December of 2021.

Post Falls Landing and Crane Pad Development

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

A landscaping architect's estimate for scope and cost was used as a basis for this capital request.

2.7 Supplemental Information

2.7.1 Identify customers and stakeholders that interface with the business case

The primary stakeholders for this project are the Upper Spokane Hydro Manager and staff at Post Falls, Environmental Resources and the City of Post Falls. Other stakeholders may be identified during project initiation.

2.7.2 Identify any related Business Cases

This Business Case is independent of other projects but the goal of completing the landing before the Post Falls North Channel Rehabilitation and the Post Falls HED Redevelopment projects would significantly enhance access to the plant facilities for heavy construction.

3.1 Steering Committee or Advisory Group Information

A formal Project Manager has been assigned to this project due to its size and complexity. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. A Steering Committee has been formed for this project. The Project Manager will manage the project through its conclusion.

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

Management of this project has included the creation of a Steering Committee which includes managers representing the key stakeholders involved in this project. The project will also be executed by a formal Project Team lead by the Project Manager.

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

Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance.

Post Falls Landing and Crane Pad Development

The undersigned acknowledge they have reviewed the Post Falls Landing and Crane Pad Development 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: *R. S. Weisbeck* Date: 8-2-2020
 Print Name: Bob Weisbeck
 Title: Manager, Hydro Ops and Maintenance
 Role: Business Case Owner

Signature: *Andrew Vickers* Date: 8/3/2020
 Print Name: Andy Vickers
 Title: Director 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	
1.0	Bob Weisbeck	Updated for 2022-2026 Capital Plan	6/22/21	

Regulating Hydro

GENERAL INFORMATION

Requested Spend Amount	\$17,150,000
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.

Regulating Hydro

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	\$17,150,000	01/2022	12/2026
Individual Capital Projects	\$17,150,000	01/2022	12/2026
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 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.

Regulating Hydro

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.

Regulating Hydro

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 prudence 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 2022 by 10% for that 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.

Regulating Hydro

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 prudence, 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 reviewed 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

Regulating Hydro

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

Signature: *R. S. Weisbeck* Date: 6/22/2021
 Print Name: R. S. Weisbeck
 Title: Manager, Hydro Ops and Maintenance
 Role: Business Case Owner

Signature: *Andrew Vickers* Date: 7/6/2021
 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

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
<i>Draft</i>	<i>Meghan Lunney</i>	<i>Initial draft of original business case</i>	<i>7/7/2020</i>	
<i>1.0</i>	<i>Meghan Lunney</i>	<i>Complete business case</i>	<i>7/28/2020</i>	

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
<i>Capital Funding</i>	<i>\$1,011,300</i>	<i>01 2021</i>	<i>12 2021</i>
<i>Activity is mandatory resulting in operational cost overage</i>	<i>\$0</i>	<i>01 2021</i>	<i>12 2021</i>

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

Spokane River License Implementation

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 prudence 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,

Spokane River License Implementation

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

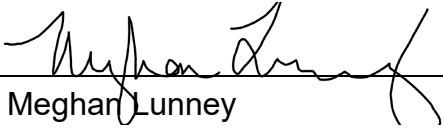
Now that the license has been issued for a term of 50-years, governance is multi-faceted and includes the Spokane River License team engaging with regulatory agencies, external and internal stakeholders in annual, five-year, and ten-year planning to implement the license and settlement agreement conditions. 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:  Date: 7/28/2020
 Print Name: Meghan Lunney
 Title: Mgr Spokane River License
 Role: Business Case Owner

Signature:  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

Upriver Park Development

EXECUTIVE SUMMARY

The Upriver Park Development project includes vacating 1/3 mile of Upriver Drive between Mission Avenue and North Center Street and developing a 3-acre park to provide improved and new public access to the Spokane River while improving public safety in this reach of a newly realigned Centennial Trail. By developing the Park, Avista will address the increase in demand for non-motorized boating use in the Upper Falls Reservoir, meeting Spokane River license requirements. In addition, the project will enhance public safety by eliminating shared use of the existing road by motor vehicles and pedestrians and cyclists. Creation of the Park will help reduce illegal camping along the shoreline by removing Jersey barriers, opening shoreline access to trail users, and by thinning and managing the vegetation between Upriver Drive and the river. The development should greatly reduce littering, dumping human waste in the area, and should enhance ecological functions along the shoreline, as non-native and invasive species will be gradually replaced with native plants. Upriver Park also addresses a goal of the City of Spokane to provide parks in historically underserved neighborhoods. Upriver Park will function as a neighborhood park and River access for people living in the adjoining Logan and Chief Garry neighborhoods, two of the lowest-income areas in the region. We are incorporating safe off-street parking and off-loading, as well as handicap access, neither of which totally exist currently. The Development also addresses remnant stormwater discharges to the River and improves stormwater management to protect the River.

Due to its proximity to the Avista campus, the development provided the lowest cost opportunity to bring Avista campus into fire code compliance and improve antiquated campus sewer and stormwater infrastructure to meet current compliance requirements. Construction of the park is estimated at \$3.5 million and would be complete in 2021 allowing for timely enjoyment of the park by the public. This is an increase in the original estimate, which was a pre-design estimate. After initial design, cost estimates were approximately \$5 million in total. We eliminated and redesigned improvements to focus the redevelopment on the shoreline, new access and trail, and value engineer other elements. Regulatory items related to fire code, stormwater and sewer elements were not in the original scope. These were discovered during the design and engineering review process. Additional requirements arose from the City's review for street realignment and additional public safety measures. Undertaking the campus-related improvements within the project rather than as a stand-alone effort saves approximately \$350,000 in re-mobilization and construction costs were these efforts undertaken separately. All told, these changes result in an increase in budget from the original \$2 million estimate to \$3.5 million. The City is releasing its ownership of its property under the to-be vacated Upriver Drive to Avista in support of this project. Should the park not be approved, the benefits of the park will not be realized resulting in ongoing public safety risks, further decline of the shoreline environment due to illegal activities, a lack of river and trail access for nearby neighborhoods, ongoing compliance and environmental risk related to fire code, discharges to the River and unmet recreation demands within the FERC project. Avista would have contributed significant financial resources into the design and permitting of the park. Last, but not least, Avista would damage its reputation with the Spokane community, customers, stakeholders, and regulatory agencies and be out of compliance with our Spokane River License commitments.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Heide Evans	Original Business Case	6/14/2019	
2.0	Allyson Tanzer	Budget change	6/28/2021	Additional funds request

Upriver Park Development

GENERAL INFORMATION

Requested Spend Amount	\$3,500,000
Requested Spend Time Period	1 year
Requesting Organization/Department	Spokane River License Implementation / C04
Business Case Owner Sponsor	Bruce Howard Dennis Vermillion
Sponsor Organization/Department	President / E01
Phase	Planning
Category	Strategic
Driver	Mandatory & Compliance

1. BUSINESS PROBLEM

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

Avista has a commitment to provide recreation improvements associated with its Spokane River Project FERC License (No. 2545), and its associated FERC and agency approved Spokane River Recreation Plan (Plan). As part of that Plan, Avista gathers recreational use data, through surveys, every five years in coordination with local, state, and federal recreation and land managers to ensure the development of recreation resources is consistent with the areas recreational need. The recreation surveys have identified an increase in non-motorized water-based recreation and the need for the development of a new river access within Upper Falls Reservoir. Additionally, Avista's customers and Spokane community members recreating along this stretch of Upriver Drive have experienced user conflicts between pedestrian, biking, transient and vehicular traffic. Vehicle accidents involving pedestrians and cyclists have been reported. In addition, the City has indicated support for eliminating the Upriver Drive/Mission intersection and re-routing arterial traffic in its new flow as a safety measure.

In addition to being related to the Spokane River License conditions, Avista has undertaken a strategic effort in recent years related to the River. Avista, founded on the banks of the Spokane River and operating the oldest continuously operated hydroelectric facility in the state there, has worked to help the community, especially those who lack convenient recreational opportunities, connect to the River. Examples include the re-dedication of Huntington Park, the establishment of aesthetic flows in Riverfront Park, improvements to the Centennial Trail, and new river access points in Washington and Idaho. These efforts have resulted in community enhancements that go beyond License compliance, providing immediate opportunities and setting examples for other landowners to make similar improvements along the Spokane to Coeur d'Alene corridor.

Constructing Upriver Park will address the increased need in water-based recreation and river access, public safety, and the ecological health of the shoreline in this area of the Upper Falls Reservoir. This area has experienced an increase in non-motorized boating over the last several years. The growing popularity of standup paddleboards, and ongoing interest in the general paddling community, as well as the development of formal and informal non-motorized boat launches by the City of Spokane, McKinstry, and NoLi Brewery demonstrate the demand for

Upriver Park Development

access. Additionally, the shoreline associated with Avista's development has seen a significant increase in illegal uses and dumping. Public safety has been threatened when encounters occur between recreational users and transient visitors camping along the river. Access to the shoreline and river by Centennial Trail users or people who live in the neighborhood is difficult and unsafe, particularly given the speed of traffic along Upriver Drive and the lack of separation between the road and trail in this area. The project will incorporate safe off-street parking and off-loading, as well as handicap access, which do not exist fully in the area. Jersey barriers, along with non-native trees obstruct river views and impact riparian ecology.

Construction of Upriver Park also provides a cost-effective opportunity to address concerns related to the Avista Campus. Currently, the campus fire safety system is out of compliance with fire regulations. Additionally, antiquated storm and sewer systems pose a direct threat to the Spokane River's water quality and risk to Avista as well. These and other facility concerns will be addressed through Park construction, saving the cost of a separate mobilization and project delivery effort.

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.**

Several drivers inform this Business Case. In terms of compliance, the project will help Avista comply with its FERC Spokane River License, and specifically the Recreation Plan approved by FERC. The Avista-owned land at the new access area will be incorporated into the FERC Project Boundary. In addition, this project fits the strategic category as originally envisioned as it enhances the quality of life for customers, particularly those who live in the low-income neighborhoods nearby with limited safe access to the River and Centennial Trail. The Park also fits the City of Spokane's strategic plan for parks and a broader goal of transforming the River corridor between Spokane and Coeur d'Alene to provide broad public benefits, all of which is in the Spokane River Hydroelectric Project area.

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

If the work is not approved, the area will remain unmanaged. The transient population will remain a challenge, pedestrian/bicycle conflicts with vehicles will continue along Upriver Drive, and the demand for non-motorized boating access to Upper Falls Reservoir will continue to grow but will not be addressed. Avista's Campus Fire System will remain out of compliance, and Avista's sewer and storm system will continue unapproved discharges to the Spokane River. The Project was deferred in 2020 due to uncertainties associated with COVID, and to undertake a re-design and value engineering to reduce costs.

If the work is deferred or not completed, Avista faces reputational risk among its stakeholders. Avista has been working closely with state and local recreation managers, the City of Spokane, as well as with the surrounding community and neighborhood councils to ensure park support and adequate coordination. Through various public communication, Avista has declared its intentions with the park development and will risk damaging its reputation if the work goes incomplete, all in addition to being out of compliance with its FERC License.

Upriver Park Development

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 can determine the project's success through metrics associated with public safety, ecological function, as well as compliance and function. Project success will be measured by a reduction in the number of illegal camps along the shoreline where the non-native trees have been thinned and the area opened to the public. Additionally, reduced pedestrian/bicyclist conflict with vehicular traffic indicates project success. Boaters and paddle-boarders will be able to use the new non-motorized boat launch to access the reservoir. The project will also provide access to the river environment for an underserved community, the Logan and Chief Garry neighborhoods. Community meetings have revealed a strong desire to see the project completed and to set an example for the broader revitalization of the entire reach of the river from the Iron Bridge to Upriver Dam. The City of Spokane is among these enthusiasts, including both staff and elected officials. Improving the Avista campus fire system and eliminating its dependence on the Spokane River will also contribute to project success and reduce O&M associated with antiquated sewer and stormwater facilities in the area.

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. 2021. Amended Spokane River and Post Falls Hydroelectric Developments Recreation Plan, FERC License Articles 416 & 417, Spokane River Hydroelectric Project FERC Project No. 2545. June 2. (Plan available upon request)

REC Resources. 2015. Amended Spokane River and Post Falls Hydroelectric Developments Recreation Plan, FERC License Articles 416 & 417, Spokane River Hydroelectric Project, FERC Project No. 2545. May 19.

REC Resources. 2010. Spokane River and Post Falls Hydroelectric Developments' Recreation Plan, FERC License Articles 416 & 417, Spokane River Hydroelectric Project, FERC Project No. 2545. May 25.

Morrison Maierle. 2019. Upriver Drive Public Road Vacation, Traffic Impact Analysis, City of Spokane, Washington, Prepared for Avista Corporation. June 2019.

Anderson Environmental Consulting, LLC. 2019. Avista Utilities – Upriver Park, Habitat Management Plan. August.

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.

Not applicable.

Complying with our license is mandatory to continued permission to operate the Spokane River Project. Since the original business case was approved, recreational demands have increased, as have illegal uses of the shoreline. Design alternatives considered included keeping one lane of traffic open, and development of a larger park. The design option keeping one lane of traffic was determined to lack many of the benefits of the design approach chosen with little, if any, cost savings. The larger park

Upriver Park Development

design, with additional amenities, was determined to be too great an investment for the marginal extra benefits.

Option	Capital Cost	Start	Complete
<i>Develop Upriver Park</i>	<i>\$3,500,000</i>	<i>October 2017</i>	<i>December 2021</i>
<i>Do Nothing (increased O&M costs, compliance risks, reputational risks)</i>	<i>\$0</i>		
<i>Build Larger Park</i>	<i>\$5M</i>		
<i>Develop Park with one lane of Upriver Dr.</i>	<i>\$4.5</i>		

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

The original \$2 million budget was a pre-design estimate. This modified request incorporates the cost of design, as well as the estimated cost of construction and internal Avista costs. At 95% design, the design consultant prepared an architect's estimate that showed construction costs estimated at approximately \$3.3M. This has now been informed by competitive bidding for the project construction. We expect to spend approximately \$500k on design and permitting services. Even with extensive value engineering efforts resulting in significant reduction in amenities and features, the project would exceed its original budget of \$2M unless construction cost was reduced to less than \$1.5M which was impossible given the cost of materials, the project duration, and increased expense associated with COVID-19 process and project delays and operations. In addition, the scope expanded to include previously unknown compliance items associated with fire protection, stormwater management and sewer alignment. Avista internal costs were not accounted for in the original approved budget.

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 project has been accumulating costs since 2017. From 2017 through 2018, the project accumulated \$34k in costs, and \$141k of costs were accumulated in 2019. Project leadership chose to delay construction into 2020 when they received a construction cost estimate that would cause the project to approach \$5 million in cost, and due to the uncertainties surrounding COVID-19 pandemic. The project spent \$319k in design and value engineering through 2020. Permitting costs will be realized in 2021. All construction costs, currently estimated at \$2.4M, would be realized in 2021, depending on the overall construction schedule.

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 Facilities Department will manage the park as an adjunct to the Avista Campus and in accordance with a Memorandum of Agreement with the City of Spokane once it is constructed. Operation and Maintenance (O&M) costs are expected to range between \$30,000 and \$50,000 annually depending on the level of management, i.e. seasonal management, snow removal, etc. It

Upriver Park Development

is important to note that all efforts are being made to develop the park in a manner that minimizes both short-and long-term O&M costs.

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

Two options were originally considered for the park. One option considered Upriver Drive narrowed down to one-way traffic going north but separated from the Centennial Trail. The other option removed Upriver Drive completely, with just the Centennial Trail bisecting the property. The preferred and selected option is the one that eliminated Upriver Drive, with just the Centennial Trail bisecting the property. It was selected because it best met the park's objectives. It was also the least costly option, because demolition costs are equal to the option that retained park of Upriver Drive. Reconstruction of the north-bound portion of Upriver Drive would add cost and not meet the overall park's objective.

Value engineering efforts also impacted park design and amenities. Reductions in scope include reduced landscaping, eliminated hardscape elements, lower-cost substitutions on park amenities and an overall reduction in the number of amenities, like a reduced number of kayak racks and benches. These reductions balance function and intent and preserve river access without adding unnecessary cost.

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.

Planning was initiated in 2017 and permitting and design should be complete in July 2021. Construction is slated to begin in Q3 of 2021 and end in Q4 of 2021. It is possible that certain aspects of the Park project could occur in 2022 depending on construction schedule, however all efforts are currently being made so that the project becomes used-and-useful in 2021.

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

The investment into Upriver Park aligns with Avista's company vision, goals, and objectives. With its added public and ecological benefits, as well as its campus improvements, the Park supports two of Avista's strategic focus areas – Our Customers, and Our People. Customer interests in non-motorized boating, river access, increased safety for Centennial Trail use are represented in the goals of the park. Our people will benefit from added safety of a compliant fire and sewer system. Removing discharges to the Spokane River fosters environmental stewardship which is an essential element of Avista's business practice. Working closely with the City and other stakeholders, Avista has demonstrated its stated value of collaboration. The park improves ties to our customers, employees, and the Spokane community.

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 prudence will be reviewed and re-evaluated throughout the project

The \$3.5M is a prudent investment given the current level of investment into the project (\$591k as of April 2021), as it will allow us to follow-through on our commitments through the Spokane River License and to stakeholders as well as see through the original vision of the park to increase river

Upriver Park Development

access, public safety, and ecological function in the project area. Additionally, the investment benefits customers and the company by bringing us into compliance and removing our sewer and stormwater discharge into the Spokane River, reducing risks.

If approved, the project should eliminate traffic flow along Upriver Drive and create a semi-natural riverside park for the neighborhood and for the public in general. Sight visibility to the river will be greatly enhanced, improving public safety and helping to create a healthy river ecosystem with the reduction of the dense non-native tree and shrub cover. Non-motorized boaters will have an informal access site to the Upper Falls Reservoir, which will help disperse use through its entire length, and bank anglers will be able to fish in the river without conflicting with the transient population that currently takes the area over during the summer and fall months. Access to and use of the Centennial Trail will be easier and safer in the area, as well.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

- City of Spokane
 - Park & Recreation Department
 - Park Board
 - Integrated Planning Department
 - Water Department
 - Sewer Department
 - Traffic Department
- Logan, Chief Garry, and Minnehaha Neighborhood Councils
- Riverview Retirement Community
- Friends of the Centennial Trail
- Spokane River Forum
- Spokane RiverKeeper
- Washington State Parks & Recreation Commission (State Parks)
- Federal Energy Regulatory Commission
- Washington Department of Fish and Wildlife
- Washington Department of Ecology

2.8.2 Identify any related Business Cases

The original Business Case was signed on 6/14/2019.

3.1 Steering Committee or Advisory Group Information

The primary Steering Committee member consists of Bruce Howard, Senior Director of the Environmental and Real Estate Department. Other Steering committee members have shifted roles as they served in development opportunities since the original business case was developed. The Steering Committee will also include Andy Vickers and Alicia Gibbs. Currently the core project team includes members from the Environmental, Facilities, GPSS, Legal, and External Communications departments.

Upriver Park Development

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

The project will be managed by an Avista project manager with leadership decisions informed by a core project team consisting of environmental, engineering, facility, inspection, legal, accounting, and communication, and contract specialists. Budget and design decisions will be made under the guidance of the steering committee and budget owners. Design and construction consultants will be utilized for performance of the work associated with the project.

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

The project will conduct weekly meetings in which project decisions will be made. Decisions will be made by consensus when possible, considering the different specialty areas of the core project team. Decisions impacting budget will be made at the appropriate level for financial approvals. The Project Manager will lead these weekly meetings and complete agenda and meeting summaries to document and monitor progress. The Project Manager will create and distribute monthly reports, as well. Change requests will be documented and monitored in the Project Change Log, managed by the Project Manager, and approved by the Steering Committee.

The undersigned acknowledge they have reviewed the [Upriver Park Development](#) 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:



Date: 7/20/21

Print Name:

Bruce Howard

Title:

Sr. Director, Environmental Affairs

Role:

Business Case Owner

Signature:



Date: 10/1/21

Print Name:

Dennis Vermillion

Title:

President & CEO

Role:

Business Case Sponsor

Signature:




Date: 7/27/21

Upriver Park Development

Print Name: _____
Alicia Gibbs

Title: _____
Director of Shared Services

Role: _____
Steering/Advisory Committee Review

Signature: _____


Date: _____
7/27/2021

Print Name: _____
Andy Vickers

Title: _____
Director, GPSS

Role: _____
Steering/Advisory Committee Review

Template Version: 05/28/2020

Use Permits

EXECUTIVE SUMMARY

Avista owns and maintains electric transmission, distribution, and natural gas facilities which cross public lands managed by a variety of state, federal and local agencies, as well as entities who own extensive tracts, such as railroads. Traditionally, we have secured long-term rights-of-way permits for these facilities, but have been required to renew them through an annual billing process. The cost of renewing these permits continues to increase each year, ranging from 3% to 10% annually, depending on the agency, thereby increasing annual O&M expenses to the company and our customers. This business case proposal is to secure long-term agreements with lump-sum payments in order to reduce overall expenses related to labor of tracking, research, and processing these annual permits. In some cases, we have been able to negotiate a lower annualized cost over the term of the permit by paying a lump sum up front. In either case, we reduce costs to the company and our customers. Making long-term lump sum payments allows us to capitalize these costs, as the permit is a long-term asset.

Without capital funding, we will continue to incur increasing annual permitting fees and related internal costs as an O&M expense. These costs affect all customers, electric and gas, in the entire Avista service territory.

VERSION HISTORY

Version	Author	Description	Date	Notes
<i>Draft</i>	<i>Rod Price</i>	<i>Initial draft of original business case</i>	<i>6/30/2020</i>	
<i>1.0</i>	<i>Rod Price</i>	<i>Completed business case</i>	<i>7/28/2020</i>	
<i>1.1</i>				
<i>2.0</i>				

Use Permits

GENERAL INFORMATION

Requested Spend Amount	\$50,000
Requested Spend Time Period	<i>annually.</i>
Requesting Organization/Department	V08 / Real Estate
Business Case Owner Sponsor	Rod Price Bruce Howard
Sponsor Organization/Department	A04 / Environmental Affairs
Phase	Execution
Category	Productivity
Driver	Performance & Capacity

1. BUSINESS PROBLEM

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

Avista owns and maintains electric transmission, distribution, and natural gas facilities which cross public lands managed by a variety of state, federal and local agencies, as well as entities who own extensive tracts, such as railroads. As these rights of way permits renew, we've been paying annually increasing fees, leading to increased O&M expenses associated with both the permit costs and the labor to process them.

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

This business case is directly tied to Reliability, Mandatory & Compliance, Performance & Capacity, and Failed Plant & Operations. In order to legally construct, maintain and upgrade our facilities on agency owned lands, we must acquire and renew rights of way permits. While we would continue doing this work without this business case, the main benefits to the customer are being able to negotiate lower fixed permit costs through lump sum payments, as well as securing long term permits which will allow us to maintain reliability in our infrastructure. In addition, we will reduce our labor costs for managing these permits. We also reduce the risk of annual permits not being renewed, or being modified unilaterally.

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

Right of way permitting on agency-owned lands is an ongoing and necessary scope of work. We will continue doing this work without an approved capital business case. This business case is based on our potential of saving the company and our customers money over the long term by capitalizing permit fees and negotiating lower costs through long term, lump sum payments.

Use Permits

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.

Annual tracking of all agency permits costs, and then completing a comparative analysis against past years.

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.

We propose that through this business case, we will work with agencies to negotiate lump sum payments for our rights of way permits, thereby securing long-term, and lower fixed costs associated with acquiring and renewing these permits.

Option	Capital Cost	Start	Complete
<i>Capitalize and negotiate lump sum payments</i>	\$50,000	01/2021	12/2021
<i>Keep paying annually increasing permit fees through O&M dollars</i>	\$0	01/2021	12/2021

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

Review of past years permit costs, we feel that \$50k annually will be enough to cover renewals.

Company Name	2014	2015	2016	2017	2018	2019
IDAHO DEPARTMENT OF PARKS AND RECREATION	\$ 7,604.20	\$ 4,199.60	\$10,983.00		\$ 1,266.80	\$ 12,572.00
LINCOLN COUNTY					\$ 687.69	
Multi-party Agreement Bonneville, Avista and Inland Power and Light			\$ 500.00			
SPOKANE COUNTY DEPT OF PUBLIC WORKS					\$ 500.00	
SPOKANE COUNTY ENGINEERS	\$ 5,000.00	\$ 5,000.00	\$ 5,564.20	\$ 5,500.00	\$ 5,500.00	\$ 5,000.00
STATE OF IDAHO DEPARTMENT OF PARKS & RECREATION	\$ 3,520.30	\$ 1,244.80	\$ 817.67	\$ 12,019.00	\$ 11,014.00	\$ 242.00
STATE OF WASHINGTON DEPARTMENT OF NATURAL RESOURCES		\$ 154.40				
UNITED STATES DEPARTMENT OF INTERIOR, BUREAU OF LAND MANAGEMENT	\$ 25,855.44	\$ 36,680.40	\$22,361.24	\$ 46,640.84	\$ 29,666.54	\$ 42,844.37
UNITED STATES DEPARTMENT OF INTERIOR, BUREAU OF RECLAMATION		\$ 800.00				
	\$ 41,979.94	\$ 48,079.20	\$40,226.11	\$ 64,159.84	\$ 48,635.03	\$ 60,658.37

Use Permits

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.

Starting in 2021, the capital cost amount will be used primarily to cover the costs of agency right of way fees. There should be minimal labor costs associated with this activity, and the annual labor costs should reduce slightly if the number of annual renewals is reduced through the negotiation of long-term permits.

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

By taking annually renewing permits, and converting them to longer-term permits, we should positively impact the labor associated with processing annual permits.

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

The only other alternative is to continue processing annual permits and paying the annually increasing fees, which is a charge to company O&M.

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 a program and the work is completed throughout the year based on when agency permits are received. They will become used and useful once the fully executed permit is in place.

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

Our proposed investment is aligned with Avista's mission of delivering reliable power to our customers at the most affordable price we can deliver. Rights of way permits are required for Avista to construct, maintain, and upgrade electric and gas infrastructure on agency owned land. Without these rights of way, we cannot meet our objectives.

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 prudence will be reviewed and re-evaluated throughout the project

Without this business case, we will still be required to do the same work, thereby continuing to pay increasing O&M costs. This program proposal is prudent, as it will help mitigate long-term expenses for the company and our customers.

2.8 Supplemental Information

Use Permits

2.8.1 Identify customers and stakeholders that interface with the business case

Electric and Gas operations are impacted by this business case as we are securing rights of way for these facilities. Avista's electric and gas customers are also affected by our ability to provide reliable and low-cost power.

2.8.2 Identify any related Business Cases

3.1 Steering Committee or Advisory Group Information

This program will be monitored by the Real Estate Manager, Sr. Director of Environmental Affairs, and Department Financial & Budget Specialist.

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

This program will be monitored by the Real Estate Manager, Sr. Director of Environmental Affairs, and Department Financial & Budget Specialist. We will evaluate the annual costs and savings to ensure the program is on track.

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

The undersigned acknowledge they have reviewed the [Use Permits](#) 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:	<i>Rod Price</i>	Date:	07/29/2020
Print Name:	Rod Price		
Title:	Mgr Real Estate		
Role:	Business Case Owner		
Signature:	<i>Bruce Howard</i>	Date:	7/29/20
Print Name:	Bruce Howard		
Title:	Sr Dir Environmental Affairs		
Role:	Business Case Sponsor		
Signature:		Date:	
Print Name:			
Title:			
Role:	Steering/Advisory Committee Review		

Use Permits

Template Version: 05/28/2020

WSDOT Franchises

EXECUTIVE SUMMARY

This program will renew expired franchises for Avista facilities located within Washington State highway rights of way. Annual costs are approximately \$250,000. In accordance with WAC 468-34 and RCW 47.44, Avista enters into 25-year agreements with the Washington State Department of Transportation (WSDOT) to permit Avista to construct, operate and maintain electric and gas facilities within Washington highway rights of way. These agreements are referred to as franchises. WSDOT manages franchises by reaches of a state highway within a county. Avista has 35 such franchises, 29 of which are expired. Franchise applications cannot be submitted without a completed "Control Zone" analysis and mitigation plan for every above-ground object within the highway right of way.

WSDOT requires compliance with control zones prior to franchise renewal. By not having these franchises completed, as well as control zone mitigation approved, Avista is at risk of not being allowed to conduct utility work within the WSDOT right of way. This would expose Avista to potential third-party claims and other costs associated with project delays. Idaho customers could be impacted and benefit from this program, as Avista's transmission facilities which cross state lines are also located in the WSDOT right of way. While we work with internal business units to relocate to private lands via an easement when advantageous, it would take many years and a considerably higher amount of funding to purchase hundreds of miles of easements from private landowners. Revised Code of Washington (RCW) 47.32.130 gives jurisdiction to WSDOT to enforce control zone guidelines. WSDOT's Utilities Manual M 22-87.07 defines the objectives, general practices, policies and procedures in the design, administration, and coordination of utility franchises within state right of way and properties impacted by above ground objects.

This business case funds the preparation of franchise renewals and control zone mitigation plans, as well as DOT charges associated with these franchise renewals.

WSDOT Franchises

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Rod Price	Initial draft of original business case	6/26/2020	
1.0	Rod Price	Complete business case	7/29/2020	
1.1				
2.0				

GENERAL INFORMATION

Requested Spend Amount	\$250,000
Requested Spend Time Period	annually
Requesting Organization/Department	V08 / Real Estate
Business Case Owner Sponsor	Rod Price 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?

29 of Avista's 35 franchises with WSDOT are expired. These franchises are required for Avista to construct, maintain and upgrade facilities located within the WSDOT right of way. In order to renew or consolidate these franchises, approximately 950 poles or above ground objects must be moved or mitigated. This program addresses the survey, drafting and permitting work in support of the mitigation efforts to be carried out through electric operations plans in the future.

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

This business case supports drivers related to Customer Service, Reliability, Mandatory & Compliance, Performance & Capacity, Asset Condition and Failed Plant & Operations. In order to continue delivering reliable, low cost power to our customers, we must be able to construct, maintain and upgrade our electric facilities in the WSDOT right of way. Without approved franchises, we are unable to do anything but emergency related work.

WSDOT Franchises

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

This is an ongoing program and has been in effect for several years. If we do not continue doing this work, Avista operations will not be able to effectively build and maintain our electric facilities located within the WSDOT right of way. The risks of not doing this work, are related to diminished electric distribution and service reliability, and even wildfire mitigation work.

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 will monitor and track the number of franchise consolidations and approvals we receive, compared to overall number submitted. We will also be working directly with the Asset Maintenance/ Wood Pole Management and Control Zone Steering Committee very closely to manage priority mitigation zones.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

Please see the Control Zone-Red Tagged Pole analysis and plan.

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 program does not include asset replacement. It covers the administrative and field activities for franchise approvals.

Option	Capital Cost	Start	Complete
<i>Capital Funding</i>	<i>\$250,000</i>	<i>01/2021</i>	<i>12/2021</i>
<i>Activity will continue – resulting in O&M overage</i>	<i>\$0</i>	<i>01/2021</i>	<i>12/2021</i>

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

This business case was developed utilizing a historical analysis of expenses related to labor and other administrative costs in completing previous franchises.

WSDOT Franchises

- 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.**

Expenses are related to the surveying, drafting and permitting work for submitting franchise consolidations.

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

This program has an impact on the Drafting department. We have accounted for that through a collaborative assignment of appropriate drafting personnel for this work.

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

There are no alternatives to renewing WSDOT franchises. This is a mandatory requirement under **WAC 468-34 AND RCW 47.44.**

- 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 program has been in effect for several years. We estimate that due to WSDOT related constraints, it will take at least 5 more years to complete these franchises. Each franchise can become used and useful once the franchise is fully executed with the state.

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

Our proposed investment is aligned with Avista's mission of delivering reliable power to our customers at the most affordable price we can deliver. Franchises are required for Avista to construct, maintain, and upgrade electric infrastructure in WSDOT right of way. Without these rights of way, we cannot meet our objectives.

- 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 prudence will be reviewed and re-evaluated throughout the project**

This work is mandatory under state law. It would be imprudent to not renew our franchises and would greatly impact our ability to serve our customers.

2.8 Supplemental Information

WSDOT Franchises

2.8.1 Identify customers and stakeholders that interface with the business case

Avista's electric customers, Electric operations, legal and WSDOT Highway engineers.

2.8.2 Identify any related Business Cases

This business case is directly related to the Control Zone-Red Tagged Pole business case. This work must be completed before they can implement actual mitigation plans.

3.1 Steering Committee or Advisory Group Information

While not under direct supervision of the Control Zone-Red Tagged Pole Steering Committee, we will work directly with that group to coordinate plans and efforts. This program has oversight from the Real Estate Manager, Sr. Director of Environmental Affairs, and Environmental Budget Specialist.

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

The project staff and Real Estate Manager review the ongoing progress. Any issues, governance or oversight needs will be reviewed between the manager, Sr. Director and Environmental Budget Specialist.

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

Decisions, prioritization and change requests related to this business case will be routed through Environmental Budget Specialist.

The undersigned acknowledge they have reviewed the [WSDOT Franchise](#) 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: *Rod Price* Date: 7/31/2020
 Print Name: Rod Price

WSDOT Franchises

Title: _____ Mgr Real Estate

Role: _____ Business Case Owner

Signature: _____ 

Date: 7/30/20

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

Boulder Park Generator Replacement

EXECUTIVE SUMMARY

Boulder Park Generating Station (BPGS) is a 24.6 MW natural gas fired power plant that provides 24.6 mw of electrical generation to Avista's service territory. In 2019, the Unit 5 generator failed and was replaced with the spare unit that was already on site.

The service code for this project is Electric Direct and the jurisdiction for the project is Allocated North, serving our electric customers in Washington and Idaho. The recommended solution is to replace each generator, over multiple years beginning in 2025, until the remaining 5 generators have been replaced, at the total cost of \$5 million. The replacement of the BPGS generators will reduce the risk of unplanned failures that would cause a disruption in the electrical generation that supports the Bulk Electric System, and increase safety around the units while in service.

Although the damage to the generators is evident and there has already been one generator failure, the replacement of the BPGS generators has been scheduled to begin in 2024 (one generator) and be complete in 2026 to help balance the capital budget between now and 2024. If this project is not funded there is high risk more generators will fail causing unplanned capital expenditure and loss of generation.

VERSION HISTORY

Version	Author	Description	Date	Notes
draft	Mike Mecham	Initial draft of original business case	7/10/2020	
	Mike Mecham	Reviewed for accuracy	7/2/2021	

GENERAL INFORMATION

Requested Spend Amount	\$ 5,000,000
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Boulder Park Generator Replacement

Requested Spend Time Period	3 years beginning in 2024
Requesting Organization/Department	T07 / GPSS
Business Case Owner Sponsor	Mike Mecham / Andy Vickers
Sponsor Organization/Department	A07 / GPSS
Phase	Initiation
Category	Project
Driver	Failed Plant & Operations

1. BUSINESS PROBLEM

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

There are six separate generators at BPGS that are rated at 5MVA, and are typically built for cruise ship engine generator sets. These units were placed in service in March of 2002, are still the original equipment, and are showing significant signs of aging. During annual maintenance in 2019 it was discovered that several of the generators had corona damage on the stator windings as they exit the core.

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**

The major driver for this project is Asset Condition and Failed Plant & Operations. BPGS has experienced a generator failure in 2019, and expect the others to fail over time and use. BPGS the ability to keep BPGS in operation helps manage Avista's ability to provide reliable electricity and the lowest cost possible by giving Avista's System Operations and Power Supply departments the ability to utilize this asset when needed.

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

There has already been one generator failure, and annual inspections have identified several of the generators have corona damage on the stator windings as they exit the core. There is no way to repair in place, and the damage will continue to worsen as the generators are used.

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.

Replacement of the 20 year old generators with new generators is the most cost effective and least risk, and will allow many more years of continued use of BPGS

Boulder Park Generator Replacement

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.**

During annual maintenance in 2019 it was discovered that several of the generators had corona damage on to stator windings as they exit the core.

Further investigation revealed that Unit 2 and Unit 4 appeared in the worse shape. There is no ground wall or gradient paint on these windings. They are just varnished tape painted with glyptal.

[Describe the proposed solution to the business problem identified above and why this is the best and/or least cost alternative (e.g., cost benefit analysis, attach as supporting documentation)]

Replace Generators – This recommended alternative would replace the complete generator, including the stator, rotor, exciter and bearings. We propose to replace one generator in 2024, two generators in 2025 and 2 generators in 2026. This option is preferred because it is the most cost effective and has the least risk, as the complete generator would be all new equipment.

Option	Capital Cost	Start	Complete
Replace Generators – one in 2024, two each in 2025 and 2026	\$5M	3/2024	12/2026
Rewind Stators – one each year beginning 2025,	\$4M	3/2024	12/2028
Rewind Stators and Rotors – one each year beginning 2025	\$6.5M	3/2024	12/2028

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

The project estimate for this equipment and associates labor are reasonable based on the vendor proposals from Kato Engineering, Leroy-Somers (the generator OEM) and K&N Electric

Boulder Park Generator Replacement

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.**

Replacement of the BPGS generators will allow continued use of the generating units at BPGS. There is very little maintenance that can be completed on the generators outside of inspection of their current condition.

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 use of BPGS by Avista's Power Supply to provide the best value energy for Avista's customers has increased from 1,000 hours in 2015 to 2,900 hours in 2019. BPGS offers the ability to frequently cycle (start and stop) that allows flexibility to the system.

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

Option 1) Replace Generators – This recommended alternative would replace the complete generator, including the stator, rotor, exciter and bearings. We propose to replace one generator in 2024, two generators in 2025 and 2 generators in 2026. This option is preferred because it is the most cost effective and has the least risk, as the complete generator would be all new equipment.

Option 2) Rewind Stators Only – This alternative would schedule one stator rewind per year for six years beginning in 2024. This is the least expensive of the repair options, but has some inherent risk. If additional work is required on the rotor, exciter and/or generator bearings, which we may not be able to identify until the equipment is in the repair shop, the cost will easily exceed the cost of a brand new complete generator by upwards of 10 – 15%.

Option 3) Rewinds Stators and Rotors – This alternative consist of a complete rewind of the stator and rotor for each generator. Again we would schedule one unit per year beginning in 2024. This alternative is not recommended as it is the most expensive alternative and that it is less expensive to replace these smaller size generators with an entirely new generator.

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.

Each generator will be placed in service and transferred to plant individually, once installed and commissioned (see schedule)

2024 Q1 Order new Generator Unit 2 - \$500K

2024 Q3 Receive and Install Generator Unit 2 – \$500K

Boulder Park Generator Replacement

2025 Q1 Order new Generator Unit 4 - \$500K
 2025 Q3 Receive and Install Generator Unit 4 – \$500K
 2025 Q1 Order new Generator Unit 6 - \$500K
 2025 Q3 Receive and Install Generator Unit 6 – \$500K
 2026 Q1 Order new Generator Unit 3 - \$500K
 2026 Q3 Receive and Install Generator Unit 3 – \$500K
 2026 Q1 Order new Generator Unit 1 - \$500K
 2026 Q3 Receive and Install Generator Unit 1 – \$500K

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

The purpose of this project is to provide funding to replace five (5) of the BPGS generators with the objective of keeping BPGS reliable and available to support the power needs of our company and our customers affordably. By doing this we support our mission of improving our customer’s lives through innovative energy solutions which includes BPGS generation. By executing the project, we insure that BPGS is 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 prudence will be reviewed and re-evaluated throughout the project

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, Power Supply, Systems Operations, and electric customers in Washington and Idaho.

2.8.2 Identify any related Business Cases

None

3.1 Steering Committee or Advisory Group Information

The Steering Committee for this project will consist of Thomas Dempsey, Mike Mecham, and Glen Farmer.

Boulder Park Generator Replacement

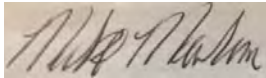
3.2 Provide and discuss the governance processes and people that will provide oversight

A project manager may be assigned. GPSS Management including the Thermal Ops & Maintenance Manager, Electrical Engineering and the Thermal Ops Manager will review at least quarterly prior to and during the project.

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

GPSS Electrical Engineering will have a key roll in monitoring and documenting this project. Since the requested funds are planned for and will not be available until 2025 the timing on which generator is replaced at which time may change, depending on the condition of the generators when the project begins.

The undersigned acknowledge they have reviewed the BP Generator 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:  Date: 7/10/2020

Print Name: Mike Mecham

Title: Thermal Ops Manager

Role: Business Case Owner

Signature:  Date: 7/6/2021

Print Name: Andy Vickers

Title: Director, GPSS

Role: Business Case Sponsor

Signature: _____ Date: _____

Print Name: _____

Title: _____

Role: Steering/Advisory Committee Review

Template Version: 05/28/2020

Cabinet Gorge HVAC

EXECUTIVE SUMMARY

The current ventilation system in the powerhouse at the Cabinet Gorge Hydroelectric Development (Cabinet Gorge) is still the original system and equipment that was installed in 1952. The system needs to be replaced because the original ventilation system controls are no longer functional and have been removed. There is no cooling capacity with the current ventilation system and the current air handling system can only be operated manually for ventilating and exhausting powerhouse air. There is no filter system for plant make up air which results in outside smoke from wildfires and dust in the outside air from entering the plant. The current summer temperatures in the powerhouse routinely rise to 90°F and additional transformers and electrical equipment planned to be installed within the powerhouse over the next three years will significantly increase internal plant heat loading.

To be able to support a satisfactory work environment for plant personnel and enable sufficient cooling for critical electrical equipment, the Cabinet Gorge powerhouse needs to have a new HVAC System with significant cooling capacity. 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. Operating Cabinet Gorge 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).

Cabinet Gorge has operational flexibility and is 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. The capacity of this plant alone is 270 MW. The estimated cost of the project is \$1.5 Million, and it is critical that this project is completed prior to the completion of the planned Cabinet Gorge Station Service upgrade which is expected to be completed in 2023. This new HVAC system will provide the needed plant cooling of this new equipment and provide sufficient heating, ventilation and air conditioning in support of normal operations of the plant. Without this system replacement, plant personnel will be subjected to unacceptably high internal powerhouse temperatures and critical electrical equipment will fail due to inadequate cooling.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Bob Weisbeck	Initial draft of original business case	6/30/2020	
1.0	Bob Weisbeck	Updated Approval Status	6/30/2020	Full amount approved
2.0	Chris Clemens	Updated for the 2022-2026 SCRUM	7/6/2021	5-year Capitol Planning Process

Cabinet Gorge HVAC

GENERAL INFORMATION

Requested Spend Amount	\$1,500,000
Requested Spend Time Period	1 years
Requesting Organization/Department	D07/GPSS
Business Case Owner Sponsor	Chris Clemens Andy Vickers
Sponsor Organization/Department	A07/GPSS
Phase	Initiation
Category	Project
Driver	Failed Plant & Operations

1. BUSINESS PROBLEM

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

The HVAC system at Cabinet Gorge is nearly 70 years old and is no longer in working order. The controls have failed and have been removed. The system is operated manually and currently only provides unfiltered outside air which is problematic during wildfire season and the introduction of dust in the powerhouse. The temperature in the plant is not regulated effectively with summertime temperatures reaching up to 90°F inside the powerhouse. New electrical upgrades to the station service will introduce a significant heat load. Without a new system the temperature in the plant will exceed acceptable temperatures for operational personnel and critical electrical equipment.

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.

The driver for this business case is Failed Plant. The heating and ventilation system is no longer functional. A new HVAC system will support the loads of critical upgrades to the electrical system, improve the working conditions of the powerhouse with filtered air and temperature control and enable the plant to function effectively into the future. Cabinet Gorge has operational flexibility and is operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match changing loads, and other types of services necessary to provide a stable electric grid and to maximize value to Avista and its customers.

Cabinet Gorge HVAC

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

There is no cooling capacity with the current ventilation system and the current air handling system can only be operated manually for ventilating and exhausting powerhouse air. There is no filter system for plant make up air which results in outside smoke from wildfires and dust in the outside air from entering the plant. The current summer temperatures in the powerhouse routinely rise to 90°F and additional transformers and electrical equipment planned to be installed within the powerhouse as part of the Station Service Upgrade Project over the next three years will significantly increase internal plant heat loading.

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 HVAC system will be designed to heat and cool the plant to adequate working temperature for plant personnel. The system will also be designed to adequately filter outside air to protect personal and equipment from outside contaminants. In addition, the system will be designed to compensate for the heat load of existing and proposed critical electrical equipment. These types of systems currently exist in other facilities similar to this powerhouse. The measure of success will be air quality and temperature control inside the powerhouse.

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.

The metric supporting the replacement of the current system is that it is no longer functional. Air intake and exhaust are now performed manually. Make up air is not filtered allowing outside contaminants such as smoke and dust to enter the powerhouse. Internal temperature of the plant is not controlled effectively. The introduction of new electrical equipment which will significantly increase the heat load, will only make the problem worse.

Cabinet Gorge HVAC

Option	Capital Cost	Start	Complete
Replace with new HVAC System	\$1,500,000	01 2023	12 2023
Continue to repair current system (O&M)	\$0	01 2021	

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

The failure of the system is the primary metric for justification of the project. The current system is not adequate to prevent contaminants from entering the plant, is manually controlled, does not adequately control internal plant temperature and will not support critical plant electrical upgrades due to the increased heat load. Without a proper HVAC system, operation of the plant will be put at risk due to unacceptable working conditions for operational personnel and risk to critical electrical equipment overheating.

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 capital cost will be spread out over two years. The first year will be primarily design and sourcing of the equipment. This is estimated to be \$500,000. The second year will include equipment removal, new equipment installation and commissioning. This is estimated to be \$1,000,000. This will not offset significant O&M charges because the equipment has failed so it is no longer maintained. The risk is to personnel due to the lack of air quality control and powerhouse temperature control and the risk to critical electrical equipment.

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 execution of this project will enable the needed upgrade of the Cabinet Gorge Station Service project. The Station Service at this plant is at the end of its useful life. The plant cannot function without this critical system. This critical system will be at risk without adequate cooling. The temperature in the plant and inadequate air quality is also no longer be acceptable.

Cabinet Gorge HVAC

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

The repair of the existing unit was considered, but the age of the equipment and the removal of failed components prevent this from being a feasible option. In addition, even if this system could be repaired, the heat load of the plant will increase with critical electrical system upgrades which are planned in the next three years.

The only feasible alternative is to install a HVAC system which will handle the new electrical loads, filter the air properly, and adequately control the temperature in the powerhouse.

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 project is expected to take two years. The effort in the first year will be devoted design and equipment sourcing. The effort in the second year will consist of equipment removal, new equipment installation and system commissioning. The transfer to plant will be at the end of the second year with the completion of commissioning.

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

Cabinet Gorge affordably supports the power needs of our company and our customers. By taking care of this plant we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By executing this project, we ensure that Cabinet Gorge is performing at a high level and serving our customers with affordable and reliable energy.

Cabinet Gorge HVAC

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 prudence will be reviewed and re-evaluated throughout the project

Industrial HVAC systems of this size and complexity fall into this range of cost. The system will need to be designed based on the estimated heat load and the air make up systems will need to be custom made to fit this powerhouse.

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. This includes the creation of a Steering Committee and a formal Project Team. Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance. The Project Manager will manage the project through its conclusion.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The primary stakeholders for this project are, the Hydro Regional Manager at Cabinet Gorge, Cabinet Gorge Plant personnel, GPSS Engineering, GPSS Construction and Maintenance, Power Supply, Environmental Resources. Other stakeholders may be identified during project initiation.

2.8.2 Identify any related Business Cases

This project will need to be completed prior to or along with the completion of the Cabinet Gorge Station Service Project. The HVAC system needs to be in place to support the increased heat load due to the critical electrical system that will be part of the station service system.

Cabinet Gorge HVAC

3.1 Steering Committee or Advisory Group Information

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. A Steering Committee will be formed for this project. The Project Manager will manage the project through its conclusion.

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

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The project will also be executed by a formal Project Team lead by the Project Manager.


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

Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance.

Cabinet Gorge HVAC

The undersigned acknowledge they have reviewed the Cabinet Gorge HVAC 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: Chris Clemens Date: 7/6/2021
 Print Name: Chris Clemens
 Title: Cabinet Gorge Ops/Maint Manager
 Role: Business Case Owner

Signature:  Date: 7/7/2021
 Print Name: Andy Vickers
 Title: Director GPSS
 Role: Business Case Sponsor

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

Cabinet Gorge HVAC

Template Version: 05/28/2020

Cabinet Gorge Station Service

EXECUTIVE SUMMARY

Cabinet Gorge Hydroelectric Development (HED) is the second largest such generating plant in Avista's hydropower fleet. It is located on the Clark Fork River in Bonner County, Idaho. With four generators, it has a 270 MW output capacity. Built in 1952, the plant has retained most of its original equipment which is now aging and at end of life. In particular, the Station Service equipment is vital to the plant's continued operation. Station Service equipment includes Load Centers, Transformers, Switchgear, Power Centers and Neutral Grounding Resistors. This equipment is used to operate the generating plant. It includes energy consumed for plant lighting, power, and auxiliary facilities in support of the electricity generation system.

It is recommended that this aging equipment be replaced to ensure the continued safe operation of the plant. Safe operation of the plant contributes to grid optimization, reliability and personnel safety. Power generation provided from within Avista's fleet maximizes the use of its own assets on behalf of its customers rather than having to procure them from other providers thereby keeping costs down for Avista's customers. As many other equipment upgrades are underway at Cabinet Gorge, the timing of these Station Service replacements has been coordinated in order to reduce plant outages. Please refer to the Cabinet Gorge Unit 3 and 4 Protection & Control Upgrade projects. In terms of risk, if this equipment is not upgraded, failure poses substantial hazards not only to the plant's operation but also to plant personnel as failed equipment can cause significant bodily injury and fire danger.

Cabinet Gorge Station Service

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Glen Farmer	Initial draft of original business case	8/1/2020	
2.0	Chris Clemens	Updated for the 2022-2026 SCRUM	7/6/2021	5-year Capitol Planning Process

GENERAL INFORMATION

Requested Spend Amount 2021	\$750,000 (approved)
Requested Spend Amount 2022	\$5,371,800 (requested)
Requested Spend Amount 2023	\$5,152,937 (requested)
Requested Spend Time Period	3 years
Requesting Organization/Department	D07/GPSS
Business Case Owner Sponsor	Chris Clemens Andy Vickers
Sponsor Organization/Department	A07/GPSS
Phase	Execution
Category	Project
Driver	Asset Condition

Cabinet Gorge Station Service

1. BUSINESS PROBLEM

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

Original equipment; manufacturers no longer support; can't add anything to Station Service due to capacity limitations; decrease in reliability and safety from the standpoint of protecting equipment and personnel.

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.**

Major drivers for this project include improved reliability and safety; manufacturers support for maintenance; address additions to capacity and obtain better insight into each individual feeder or starter.

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

Station Service components are being designed the from 13kV level to the lowest voltage and approaching it as one system rather than individually addressing equipment failures as they arise.

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.

Reduced failures and increased reliability would demonstrate successful delivery on identified objectives.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

No studies were performed however, in the 2000's, additional protection was added to the existing main feeders to improve safety. Feeder breakers were rebuilt in 2006. It was identified that the Power Centers and Load Centers were in poor condition and without replacement parts, as equipment failed, we would have to take either the Load Centers or Power Centers offline to attach disconnects to the bus. This would allow us to place equipment back in service but would leave us exposed from a protection standpoint.

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. N/A

Option	Capital Cost	Start	Complete
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Cabinet Gorge Station Service

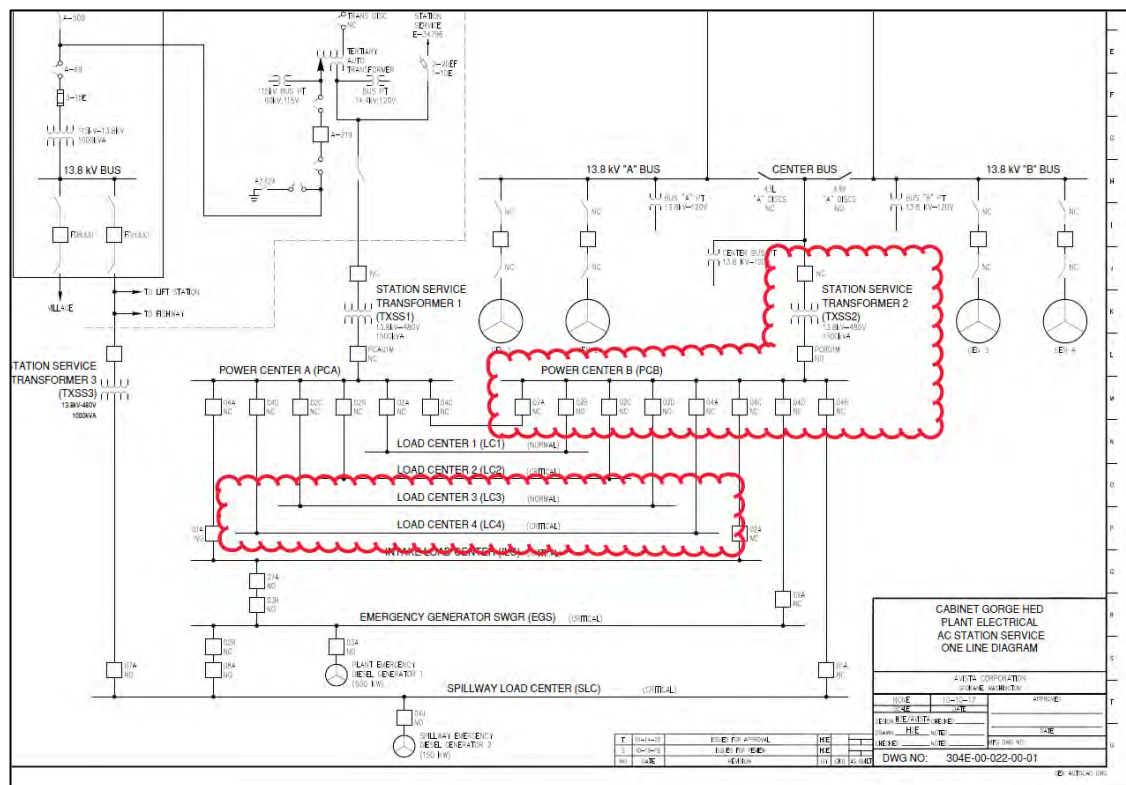
Address Emergency Side of Station Service	\$2,500,000	2017	2021
Power Center A and associated equipment	\$5,371,800	01/2022	12/2022
Power Center B and associated equipment	\$5,152,937	01/2023	12/2023

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

When preparing this capital request for Emergency Loads, Power Centers and Load Centers, we worked with Power Engineers to develop a game plan and preliminary budgets.

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 proposed solution is to address Station Service as a whole; to help with budget and resources, the plan is to address the emergency loads first followed by Power Center A and then Power Center B. The diagram below shows what would be replaced in Power Center B.



This approach allows for minimal outage to loads as equipment is replaced.

Cabinet Gorge Station Service

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

Improve operational insight into the Station Service from the standpoint of voltage, current, run time and starts.

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

Due to the number and variety of projects taking place at Cabinet Gorge, we were faced with prioritization of projects to ensure the best use of resources, meeting budgets and minimizing outage impacts as well as addressing safety concerns. This caused us to re-evaluate the implementation of this project over several years which is stated above.

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 project is broken into three phases to allow for budgets, resources and in-service dates to correspond to work completed.

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

Upgrading the Station Service equipment at Cabinet Gorge contributes to the Safe and Responsible design, construction, operation and maintenance of Avista's generating fleet.

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 prudence will be reviewed and re-evaluated throughout the project.

We ranked this project based on a ranking matrix to ensure prudent consideration of costs, scheduling and personnel resources.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case.

Electric shop, mechanical shop, relay shop, engineering, Operations, SCADA, Protection, Environmental, Project Management and Power Supply.

2.8.2 Identify any related Business Cases

Cabinet Gorge HVAC Replacement Project

Cabinet Gorge 15kV Bus Replacement

3.1 Steering Committee or Advisory Group Information

The Steering Committee consists of the following members: Manager of Project Delivery, Manager of Maintenance and Construction, Manager, Manager of Hydro Operations & Maintenance.

Cabinet Gorge Station Service

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


Persons providing oversight include: Generation Electrical Engineering Manager, Generation Controls Engineering Manager, General Forman of Protection, Control and Meter technicians, Manager C&M - Electric Shop, Cabinet Gorge Plant Manager, and Manager Engineering Protection

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

The persons identified in Section 3.2 will be called on to evaluate recommendations raised from the stakeholder group. Documented decisions will be stored in the project folder located on the department network drive.

The undersigned acknowledge they have reviewed the Cabinet Gorge Station Service 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: Chris Clemens Date: 7/6/2021
 Print Name: Chris Clemens
 Title: Cabinet Gorge Ops/Maint Manager
 Role: Business Case Owner

Signature:  Date: 7/7/2021
 Print Name: Andy Vickers
 Title: Director, GPSS
 Role: Business Case Sponsor

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

Template Version: 05/28/2020

Cabinet Gorge Stoplogs

EXECUTIVE SUMMARY

Cabinet Gorge Spillgates are original to the project (early 1950's vintage). The spillgates are old and in need of replacement. Without a set of reliable stop logs we cannot accomplish the spillgate work that is expected to take place over the next several years. Stop logs are used to isolate spillway gates from the reservoir for the Cabinet Gorge Hydroelectric project. Each stop log assembly comprises nine individual stop log elements or units, which when combined, will allow dewatering of one spillway gate. Each stop log unit is predominantly a welded steel structure designed to fit inside stop log guides embedded inside a large concrete structure, and to minimize water seepage by means of a rubber seal that is compressed under unit self-weight and hydrostatic forces. Without these structures, we cannot efficiently and safely perform the upcoming spillgate work.

Currently Cabinet Gorge spillgates are in need of repair due to missing rivets, bent members, worn-out seals and heavy corrosion. It is worth mentioning that when the condition assessment was performed at Cabinet Gorge, the Spillgates ranked poorly. If those repairs are not made, we pose the risk of a spillgate being out of operational use or a possible gate failure, which could result in an uncontrolled release of water. This would not be in the best interest of public safety, plant safety, and would negatively affect our relationship with FERC, our main governing body and our customers at this facility. 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. Operating Cabinet Gorge 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).

Cabinet Gorge has operational flexibility and is 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, as well as to maximize value to Avista and its customers. The capacity of this plant alone is 270 MW. The estimated cost of the project is \$1.2 Million. It is critical that this project is completed prior to the completion of the planned Cabinet Gorge Spill gate upgrade which is expected to be starting in 2024.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Andrew Burgess	Updated Draft of original business case.	7/6/2020	Budget and year change
2.0	Chris Clemens	Updated for the 2022-2026 SCRUM	7/6/2021	5-year Capitol Planning Process

Cabinet Gorge Stoplogs

GENERAL INFORMATION

Requested Spend Amount	\$1,200,000
Requested Spend Time Period	1 years
Requesting Organization/Department	D07/GPSS
Business Case Owner Sponsor	Chris Clemens Andy Vickers
Sponsor Organization/Department	A07/GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

The Cabinet Gorge spillgates are nearly 70 years old and are in need of repair due to missing rivets, bent members, worn out seals and heavy corrosion. In order to do this needed spillgate work a functional set of Stoplogs must be designed and built prior to spillgate work commencing in 2024. These stoplogs would also help increase the safety factor of the spillway by giving the ability to stop water flow should one of the old spillgates fail or get stuck in the open position. The condition assessment performed in 2018 ranked the spillgates at Cabinet in “poor condition”. A new set of stoplogs are needed to provide stability, reliability and safety of the aging spillway.

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

The driver for this business case is Asset Condition . The stoplogs we have are no longer functional and require major work to become of use. A new set of stoplogs will support the spillgate work, which will provide stability and longevity in the aging spillway into the future. Cabinet Gorge has operational flexibility and is operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match changing loads, and other types of services necessary to provide a stable electric grid and to maximize value to Avista and its customers.

Cabinet Gorge Stoplogs

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

Currently, there is not a functional set of stoplogs at Cabinet. Needless to say we cannot effectively begin spillgate work in 2024 until a functioning set is constructed. If we stick with the current plan and construct the stoplogs in 2023 we can perform the much needed work to the spillgates and keep the current plan in motion. If this is deferred it will prolong the work to the spillway gates and will put the plant and spillway at risk.

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 stoplogs would be designed in a similar fashion as Noxon's newly built stoplogs. With the improved design they were able to achieve a better fit to the slot, a tighter seal to mitigate leakage through the stoplog and a safer and more efficient way to pick and set the stoplogs into place. Using the design and construction criteria applied at Noxon for their stoplogs will help ensure that we end up with a set of stoplogs that function properly and provide a level of safety for the expected spillgate work and at Cabinet Gorge.

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.

The metric supporting the replacement of the current stoplogs is that they are no longer functional or useful. The original stoplogs in their current state are not feasible or safe to use. Estimated cost to refurbish the existing set is 700-800k.

Option	Capital Cost	Start	Complete
Replace with new Stoplogs	\$1,200,000	01 2023	12 2023
Refurbish existing set (O&M)	\$700,000	01 2023	12 2023

Cabinet Gorge Stoplogs

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

A field study was performed on the current set of stoplogs by McMILLEN JACOBS in 2017. The study showed that the current set of stoplogs is in “satisfactory” condition. The paint, seals and welds were noted as needing to be addressed. However, these are the original stoplogs and it may be hard to get an engineer to sign off on these as ever being deemed safe to use. The study showed that refurbishment of the existing could be accomplished but the O&M cost estimated to be 700-800k to refurbish would be more than half the cost of a complete new set. The old set have never been placed in service, so there is some risk involved in refurbishing. New stoplog design would be similar to the Noxon set that was built in 2018. Major spillgate work in 2024 will require a well designed functional set of stoplogs to complete the work safely.

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 capital cost of \$1,200,000 will be spent in 2023. In first quarter design/engineering will take place. Second quarter material will purchased and fabrication will begin. Third quarter fabrication complete. Fourth quarter delivery/commissioning of the stoplogs. If this request moves forward we can offset O&M costs that would be incurred to refurbish the existing set. There is significant risk involved with not procuring a set of stoplogs prior to the spillgate work scheduled for 2024. The original 1950's vintage spillgates have exceeded there expected life cycle and are in need of replacement.

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 timing and execution of this project will enable the needed upgrade of the Cabinet Gorge Spillgate project to proceed in 2024. The spillgates at Cabinet Gorge are original to the project and are at the end of their useful life. With Noxon and Cabinet preparing to officialy enter the EIM in April 2022 it is expected that we will Operate and cycle the spillgates even more once we enter the market. Failure of a spillgate would impose significant operational impacts to the plant , power schedulers, and public by limiting our ability to safely and efficiently control the flow of water through the dam.

Cabinet Gorge Stoplogs

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

The repair of the existing set of stoplogs was considered but due to the high cost to refurbish and the outdated design of the old stop logs, this is not the most reliable and safest option.

The most feasible and safest option is to design and build a new set of stoplogs for the anticipated spillgate work in 2024.

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.

In first quarter design/engineering will take place. Second quarter material will be purchased and fabrication will begin. Third quarter fabrication complete. Fourth quarter delivery/commissioning of the stoplogs. Transfer to plant will occur at the end of the first year once commissioning is complete.

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

Cabinet Gorge affordably supports the power needs of our company and our customers. By taking care of this plant we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By executing this project, we ensure that Cabinet Gorge is 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 prudence will be reviewed and re-evaluated throughout the project

Industrial Stoplogs of this size and weight fall into this range of cost. The overall length and width of the stop logs are similar to the set that was built in 2018 for the upcoming Noxon spillgate project. We used the dollar figure spent on Noxon's stoplogs to determine the overall project cost at Cabinet.

Cabinet Gorge Stoplogs

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. This includes the creation of a Steering Committee and a formal Project Team. Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance. The Project Manager will manage the project through its conclusion.

2.8 Supplemental Information

2.8.1 Identify Customers and Stakeholders that identify with the Business Case.

The primary stakeholders for this project are, the Hydro Regional Manager at Cabinet Gorge, Cabinet Gorge Plant personnel, GPSS Engineering, GPSS Construction and Maintenance, Power Supply, Environmental Resources. Other stakeholders may be identified during project initiation.

2.8.2 Identify any related Business Cases

This project will need to be completed prior to the spillgate project expected to start in 2024. The stoplogs will need to be designed built and commissioned prior to any major spillgate work at Cabinet Gorge.

3.1 Steering Committee or Advisory Group Information

A formal Project Manager will be assigned to this project. The project will be managed within project management practices adopted by the Generation Production and Substation (GPSS) Department. A Steering Committee will be formed for this project. The Project Manager will manage the project through its conclusion.

Cabinet Gorge Stoplogs

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


Management of this project will include the creation of a steering committee which will include managers representing the key stakeholders involved in this project. The project will also be executed by a formal Project Team lead by the Project Manager.

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

Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance.

The undersigned acknowledge they have reviewed the Cabinet Gorge Stoplogs 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: Chris Clemens Date: 7/6/2021
 Print Name: Chris Clemens
 Title: Cabinet Gorge Ops/Maint Manager
 Role: Business Case Owner

Signature:  Date: 7/7/2021
 Print Name: Andy Vickers
 Title: Director GPSS
 Role: Business Case Sponsor

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

Cabinet Gorge Stoplogs

Template Version: 05/28/2020

Cabinet Gorge Unwatering Pump Upgrade

EXECUTIVE SUMMARY

Cabinet Gorge Hydroelectric Development (HED) is the second largest generating plant in Avista's hydropower fleet. It is located on the Clark Fork River in Bonner County, Idaho. With four generators, it has a 270 MW output capacity. Built in 1952, the plant has retained most of its original equipment which is now aging and at end of life. This plant was designed for base load operation, but today is called on to not only provide load but to quickly change output in response to the variability of wind generation, to changing customer loads and other regulating services needed to balance the system load requirement and assure transmission system reliability.

In order to respond to these new demands, it is necessary to upgrade many of the plant's original systems. One of those critical systems are the unwatering pumps. The unwatering system at Cabinet Gorge consist of two unwatering sumps, each housing three pumps, one 50HP and two 200HP pumps. The 50HP (1,000 GPM) pumps are used to pump out water from normal plant leakage. The 200HP (5,000 GPM) pumps are used to drain out generating units when performing routine maintenance. The pumps, original to the plant, are progressively requiring increasing maintenance. Replacing all six pumps with new pumps at a cost of \$800,000 is recommended. Timing for this work is related to Avista's entrance into the Energy Imbalance Market (EIM). The risks for not completing these upgrades include an inability to perform critical maintenance, potentially flooding the plant, and thereby jeopardizing Avista's ability to serve its customers.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Chris Clemens	Initial draft of original business case	10/25/2020	

Cabinet Gorge Unwatering Pump Upgrade

GENERAL INFORMATION

Requested Spend Amount	\$800,000
Requested Spend Time Period	1 year
Requesting Organization/Department	D07/GPSS
Business Case Owner Sponsor	Chris Clemens Andy Vickers
Sponsor Organization/Department	A07/GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

The problems being addressed are the plant unwatering pumps at Cabinet Gorge. These pumps have reached the end of their life to provide reliable plant dewatering.

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.

The current plant unwatering pumps were installed during the original plant construction in the early 1950's. These pumps can no longer be maintained, due to the manufacturer not supporting the equipment. Customers will be benefited through higher reliability of new pumps: i.e. reduced downtime during maintenance evolutions and manufacturer support of the replaced equipment. Also, the original pumps were designed with an oil lubricating system that has the potential to get oil into the river while the pumps are in operation. The new pumps will have a water lubricating system that will meet current environmental requirements.

Cabinet Gorge Unwatering Pump Upgrade

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

The pumps have reached the end of their service life. They are a critical plant system and without their reliable operation, the plant could easily flood and/or limit the ability to perform unit maintenance. As we go into the EIM market, unit maintenance outages will be scheduled one year in advance and schedule adherence is crucial to plant operation. If these pumps fail, we could jeopardize the maintenance schedule and forgo much needed preventative maintenance activities. In addition, in the case of a failure, the replacement parts or new pumps would have to be manufactured, increasing the length of the downtime. The current systems are not environmentally-friendly so there is a risk in continually polluting our rivers with these outdated oil lubricated pumps.

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.

By replacing the current pumps with new pumps, we will provide consistency with industry standards. These upgrades will improve the plant's overall reliability. This will also reduce current maintenance costs and provide many years of efficient, reliable and environmentally-sound plant dewatering operations.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

No studies have been performed.

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.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Replace all six pumps and check valves over a one-year period.	\$800,000	01 2022	12 2022
Replacing only the four large pumps and check valves over a one-year period.	\$600,000	01 2022	12 2022

Cabinet Gorge Unwatering Pump Upgrade

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

Capital planning consists of bids from manufacturers to determine the best cost and schedule. Engineering and vendors have been consulted to determine industry best practices and to determine installation costs and schedules

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.

Installations and commissioning of purchased equipment will take place in 2022. Maintenance costs will be reduced because the current pumps require ongoing maintenance. In 2019, Unwatering pump #1 was removed from service because of high vibration and the motor was pulling 60 amps over the nameplate rating. The mechanical crew spent 2 weeks removing the motor and sending it in to be cleaned, baked and dipped. Then the bearings were replaced, and the motor was reinstalled. Neither problem (vibration nor high amperage) was resolved. The cost to perform this maintenance was \$50,000. Due to the age of these original pumps, it is difficult to get parts. Similarly, it is not sustainable to fix the vibration issues because the pumps and motors have been modified through the years to keep them in service. It is believed that replacing the pumps will be more cost effective than trying to maintain the current pumps. Reliability will be improved because the new pumps will be maintenance-free for many years.

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 successful upgrade of the system will allow the plant to operate more reliably during the future.

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

There is an alternative in only replacing four of the six pumps. The smaller pumps have had the motors replaced 20 years ago, but the pump itself was not overhauled. The larger pumps, if replaced, could act as a backup if the smaller pump was to fail. Though the smaller pumps would still be utilizing the oil lubricating system. They still should be replaced in the future to meet environmental standards.

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.

This project would take place over a one-year period. We will procure and install all six pumps within that timeframe. The work would take 1 week per pump, totaling six weeks. We would purchase six pumps in January 2022 and start the installation in June of 2022.

Cabinet Gorge Unwatering Pump Upgrade

There would be no outages or generation lost during these upgrades. We will be able to replace one pump at a time, keeping the plant unwatering sumps in service.

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

Upgrading the plant unwatering pumps at Cabinet Gorge contributes to the safe and responsible design, construction, operation and maintenance of Avista's generating fleet.

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 prudence will be reviewed and re-evaluated throughout the project

We ranked this project based on a ranking matrix to ensure prudent consideration of cost, scheduling and personnel resources. These six pumps are ranked in poor condition. There are only a few assets within the Hydro Department with a poor rating. This shows the need and urgency to replace these pumps.

Cabinet Gorge HED Asset Group	Condition Rating	Unwatering Pumps #1,2,4 &	Unwatering Pumps #3	Unwatering Pumps #6	Unwatering Pumps #7	Pump #8 Backup (for #7)
Unwatering Pumps	Marginal	-0.8	2.8	2.8	9.3	4.2
		Poor	Poor	Poor	Good	Marginal

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The Mechanical shop, Electric shop, Engineering, Operations, Environmental, and Project Management are required.

2.8.2 Identify any related Business Cases

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The Steering Committee consists of the following members: Plant Manager, Chief Operator, Station Mechanic and Station Electrician.

Cabinet Gorge Unwatering Pump Upgrade

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

Persons providing oversight include: Generation Mechanical Engineer, Mechanical Shop Forman and Station Mechanic.


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

The persons identified in Section 3.2 will be called on to evaluate recommendations raised from the Stakeholder Group. Documented decisions will be stored in the project folder located on the department network drive.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Cabinet Gorge Unwatering Pump Upgrade 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: Chris Clemens Date: 7/6/2021
 Print Name: Chris Clemens
 Title: Cabinet Gorge Ops/Maint Manager
 Role: Business Case Owner

Signature:  Date: 7/7/2021
 Print Name: Andy Vickers
 Title: Director GPSS
 Role: Business Case Sponsor

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

Generation Masonry Building Rehabilitation

EXECUTIVE SUMMARY

Several Buildings located at Avista’s generating facilities are constructed with masonry and were constructed over 100 years ago. These buildings include: The Little Falls Powerhouse, the Little Falls Gate Building, the Long Lake Powerhouse, the Nine Mile Powerhouse, the Post Street Station, The Post Falls Powerhouse, the Post Falls Substation Building and the Ross Park Building (eight buildings in six locations). The grout and brick in many cases has begun to fail which is creating a serious personnel and public hazard as bricks become loose in the walls and parapets and fall to the ground. This has become critical, especially during the freeze and thaw cycles in the spring. The condition of some of the masonry structures, especially those near the top of the walls and parts of the roof structure have exceeded their useful life and pose a threat to the structural integrity of the buildings.

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

The solution to this problem is to assess each building and dismantle and rebuild the damaged sections of the walls and support structures with methods and materials that will restore the structural integrity of the building. This project is expected to cost \$6,000,000 over a period of six years in order to address the issues with all eight buildings in the six locations.

The business driver for this project is Asset Condition. Without action, the driver may become Failed Plant. Without this project, O&M costs will be spent to spot repair the buildings as required. This has been the strategy in the past. As the buildings continue to age, these costs will rise. In addition, the spot repairs will not prevent more bricks from becoming loose every year. This poses an unacceptable risk of injury and possible death if the bricks fall on personnel at the plant or in the case of the Post Street Station in downtown Spokane, members of the public. If the problem is not remedied in a timely manner, the structural integrity of the buildings will be compromised which could result in the collapse of sections of the buildings which would endanger personnel and adversely affect operations.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Bob Weisbeck	Initial draft of original business case	7/1/2020	
1.0	Bob Weisbeck	Final version approved	7/6/2020	
2.0	Bob Weisbeck	Updated for 2022 to 2026 Capital Plan	6/22/2021	

Generation Masonry Building Rehabilitation

GENERAL INFORMATION

Requested Spend Amount	\$3,000,000
Requested Spend Time Period	7 years
Requesting Organization/Department	A07/GPSS
Business Case Owner Sponsor	Bob Weisbeck Andy Vickers
Sponsor Organization/Department	A07/GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

Several Buildings located at Avista's generating facilities are constructed with masonry and were constructed over 100 years ago. These buildings include: The Little Falls Powerhouse, the Little Falls Gate Building, the Long Lake Powerhouse, the Nine Mile Powerhouse, the Post Street Station, The Post Falls Powerhouse, the Post Falls Substation Building and the Ross Park Building. The grout and brick in many cases has begun to fail which is creating a serious personnel and public hazard as bricks become loose in the walls and parapets and fall to the ground. This has become critical, especially during the freeze and thaw cycles in the spring. The condition of some of the masonry structures, especially those near the top of the walls and parts of the roof structure have exceeded their useful life and pose a threat to the structural integrity of the buildings.

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.**

The business driver for this project is Asset Condition. Without action, the driver may become Failed Plant. Without this project, O&M costs will be spent to spot repair the buildings as required. This has been the strategy in the past.

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

As the buildings continue to age, these costs will rise. In addition, the spot repairs will not prevent more bricks from becoming loose every year. This poses

Generation Masonry Building Rehabilitation

an unacceptable risk of injury and possible death if the bricks fall on personnel at the plant or in the case of the Post Street Station in downtown Spokane, members of the public. If the problem is not remedied in a timely manner, the structural integrity of the buildings will be compromised which could result in the collapse of sections of the buildings which would endanger personnel and adversely affect operations.

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.

Over the past two years, O&M costs have been incurred to spot repair critical conditions in some of the buildings. This has proven to be only a temporary fix. The measure of success in this project would be the complete rebuild of the damaged structures so that the failing walls and structure would be remedied and falling debris would be eliminated.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

Over the past two years, repairs were made to the Long Lake Powerhouse and the Post Street Station. In 2019 approximately \$122,000 was spent to repair Long Lake. In 2020, \$297,000 was spent to repair Post Street Station. These expenditures were considered O&M and only partially repaired the issue. This project would reduce or eliminate these costs since the project would dismantle and rebuild sections to restore the structural integrity of the buildings and greatly reduce the likelihood of falling debris.

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.

The grout and brick in many cases has begun to fail which is creating a serious personnel and public hazard as bricks become loose in the walls and parapets and fall to the ground. This has become critical, especially during the freeze and thaw cycles in the spring. The condition of some of the masonry structures, especially those near the top of the walls and parts of the roof structure have exceeded their useful life and pose a threat to the structural integrity of the building

2.

Option	Capital Cost	Start	Complete
Rehabilitate Existing Masonry Structures	\$3,000,000	01 2022	12 2027
Continue to repair current system (O&M)	\$0	01 2021	12 2025

Generation Masonry Building Rehabilitation

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

The O&M costs of repairing the buildings was considered in this project. Also, the experience of the spot repairs has shown that these repairs will not prevent more bricks from becoming loose every year. This poses an unacceptable risk of injury and possible death if the bricks fall on personnel at the plant or in the case of the Post Street Station in downtown Spokane, members of the public. Experience has also shown If the problem is not remedied in a timely manner, the structural integrity of the buildings will be compromised which could result in the collapse of sections of the buildings which would endanger personnel and adversely affect operations.

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.

Over the past two years, repairs were made to the Long Lake Powerhouse and the Post Street Station. In 2019 approximately \$122,000 was spent to repair Long Lake. In 2020, \$297,000 was spent to repair Post Street Station. These expenditures were considered O&M and only partially repaired the issue. This project would reduce or eliminate these costs since the project would dismantle and rebuild sections to restore the structural integrity of the buildings and greatly reduce the likelihood of falling debris. Rehabilitation of these structures is considered capital and the annual expenditure is forecast to be \$500,000 per year for six years

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 number and duration of outages in the hydro generating facilities should be minimal due to this work. Much of the work will be done on the external sections of the building. However, when work is being performed above or adjacent to operating units, outages may be required to install scaffolding and other protective equipment.

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

The alternative that has been considered and tried is the spot repairs to sections of the buildings when the deterioration has caused bricks to fall and structures to begin

Generation Masonry Building Rehabilitation

to fail. These repairs did not prevent more bricks from becoming loose every year. This has posed a risk as the bricks fall several stories from the walls and roof structure. Repairs have been performed at Long Lake and Post Street station and have not remedied the problem. Experience has also shown If the problem is not remedied in a timely manner, the structural integrity of the buildings will be compromised which could result in the collapse of sections of the buildings which would endanger personnel and adversely affect operations.

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 project is expected to take six years in order to remedy the masonry condition in eight facilities. The strategy is to work on one location per year until all the issues have been addressed. These buildings include: The Little Falls Powerhouse, the Little Falls Gate Building, the Long Lake Powerhouse, the Nine Mile Powerhouse, the Post Street Station, The Post Falls Powerhouse, the Post Falls Substation Building and the Ross Park Building.

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

The structural integrity of these buildings is essential in supporting the function of the generating facilities on the Spokane River. These plants affordably support the power needs of our company and our customers. By taking care of these facilities we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By rehabilitating these buildings, 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 prudence will be reviewed and re-evaluated throughout the project

The cost of repairing the Post Street Station amounted to approximately \$297,000. This addressed immediate issues on one wall and part of the roof structure. The size and configuration of the masonry buildings considered in this project are similar. In order to remedy the structural issues of each plant, it is expected to be three times this amount. The projected estimate is \$1,000,000 per locations. The work is being spread out over seven years to enable the use of one contractor and control costs.

Generation Masonry Building Rehabilitation

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The primary stakeholders for this project are, the Hydro Regional Managers for the Upper Spokane plants and Long Lake/Little Falls, Plant personnel, Facilities, Power Supply, Environmental Resources and the City of Spokane. Other stakeholders may be identified during project initiation.

2.8.2 Identify any related Business Cases

This Business Case should be independent of other projects.

3.1 Steering Committee or Advisory Group Information

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. A Steering Committee will be formed for this project. The Project Manager will manage the project through its conclusion.

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

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The project will also be executed by a formal Project Team lead by the Project Manager.

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

Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance.

Generation Masonry Building Rehabilitation

The undersigned acknowledge they have reviewed the Cabinet Gorge HVAC 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: *R. S. Weisbeck* Date: 6/24/21
 Print Name: R. S. Weisbeck
 Title: Manager, Hydro Ops and Maintenance
 Role: Business Case Owner

Signature: *Andrew Vickers* Date: 7/6/2021
 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

Generation Protection Upgrade Program

EXECUTIVE SUMMARY

The purpose of this program is to replace existing obsolete protection relays at generating facilities with Avista standard digital multifunction protective relays. Protective relays in generation facilities must quickly detect high energy faults and isolate equipment to ensure personnel safety and avoid major equipment damage. Multiple generation sites operate with obsolete electromechanical and solid state protection relays. Electromechanical relays are subject to mechanical drifting of settings that decrease relay operation reliability and requiring addition maintenance. Aging solid state relays are subject to sudden electronic failures and difficult to accurately maintain settings. The replacement options for both types of relays are very limited and failure could result in an extended unplanned outage. Also, older relays do not have the communication, metering, and event reporting functions standard in modern digital multifunction relays. These features are essential to effectively monitoring system operation and troubleshooting faults. Upgrading protection relays will improve reliability by reducing the risk of serious damage to major generation equipment, reduce outage time to troubleshoot protection events, and improve the safety of personnel in Avista's generating facilities. If this work is not or approved or deferred, operation and maintenance of these systems will become more costly, less reliable and increasingly dangerous.

This program will fund generator protection relay replacements at Rathdrum Combustion Turbine, Monroe Street HED, Boulder Park Generating Station, and Northeast Combustion Turbine. These sites have obsolete relays without any upgrade plan. The program will fund site specific projects over five years and total cost is estimated to be \$1,575,000.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Jeremy Winkle	Original submission	7/7/2021	

GENERAL INFORMATION

Generation Protection Upgrade Program

Requested Spend Amount	\$1,575,000
Requested Spend Time Period	5 years
Requesting Organization/Department	Generation Production Substation Support
Business Case Owner Sponsor	Jeremy Winkle Andy Vickers
Sponsor Organization/Department	Generation Production Substation Support
Phase	Initiation
Category	Program
Driver	Asset Condition

Generation Protection Upgrade Program

1. BUSINESS PROBLEM

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

Protection relays required to protect plant personnel from danger condition and prevent costly equipment failures such as generators are obsolete. These relays create risk to reliable and safe generation operations that can be reduced with the upgrade to modern digital multifunctional relays.

Multiple generation sites operate with obsolete electromechanical and solid state protection relays. Electromechanical relays are subject to mechanical drifting of settings that decreasing relay operation reliability and requiring addition maintenance. The requirement to relays are more stringent than modern relays and require additional technician training. Aging solid state relays are subject to sudden electronic failures and accurate protection setting are difficult to establish and maintain. The replacement options for both types of relays are very limited and expensive, and failure could result in an extended unplanned outage.

There are significant safety concern associated with obsolete relays. Technicians are exposed shock hazards during relay testing due to the physical configuration of the test relays. If generation protection systems do not function properly due to sudden failure or setting drift, the risk of failing to properly isolate the fault and excessive damage and exposing plant personnel to hazardous conditions significantly increases.

Compared to modern digital multifunctional relays, the protection, monitoring, and troubleshooting capabilities of obsolete relays is very limited. Modern relays have following capabilities that will improve protection system reliability:

- Remote monitoring of protection system health
- Event capture capability that can be remotely accessed to improve troubleshooting
- The ability to implement state of the art protection schemes

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**

The primary driver for this business is asset condition. The relays designated to be replaced as with this business care are obsolete and minimal spare relays are available for immediate replacement in the event of a failure. The protection capabilities of existing relay are limited and replacement will enhance schemes protecting costly equipment including generators. This will benefit the customer by increasing generation operational reliability reducing generator outage time and avoiding costly repairs due to major damage.

Generation Protection Upgrade Program

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

Protection relays are extremely critical to reliable and safe operations. Upgrading to modern multifunction relays will immediately increase safety, reduce O&M costs, and improve reliability.

If this work is not or approved or deferred, operation and maintenance of this systems will become more costly and less reliable. Currently, replacement relays are either impossible or difficult to procure and emergent replacement will likely result in an extended unplanned outage. The additional O&M costs to train technicians to safely and accurately maintain the relays will continue to increase. Overall, Avista's ability to safely and reliably operate generation units utilizing obsolete relays will suffer.

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 investment in the removal of obsolete relays and installation of modern multifunction relays to these sites will be measured by the follow:

- The reduction in O&M costs associated properly troubleshoot protection system and maintaining protection relays will be reduced.
- Safe and reliable operation of generation facilities will improve with reduce outage time and emergency repair costs due to obsolete protections systems.

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.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
[Recommended Solution] Upgrade all obsolete protection relays (RCT, MS HED, NECT, BPGS)	\$1,575,000	01 2022	12 2026
[Alternative #1] Upgrade protection relays at RCT and MS HED	\$625,000	01 2022	12 2023
[Alternative #2] Repair and Maintain existing Protection Relays	\$0	N/A	N/A

The recommend solution is replacing all obsolete relays at site without any planned upgrades. After the completion of these projects along with existing upgrade projects, all protection relays at Avista's generating facilities will be upgrade to modern digital multipurpose relays.

Generation Protection Upgrade Program

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

Multiple parties responsible for design, maintenance, monitoring, commissioning and troubleshooting of generation protection systems were consulted while preparing this capital request.

-Protection engineers noted the challenges to troubleshoot systems without event reporting and deteriorating reliability of aging relays.

-System planning identified enhance protection schemes that could be implement if new relays are installed to reduce risks to company assets and personnel.

-Protection Control and Metering Technicians described the challenges to maintain the aging relays. Their primary concerns evolved around the training required and the existing shock hazards.

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 design and construction required to replace the aging and obsolete protection relays will take place over a five year period. The expect design and construction schedule will be as follows:

2022

\$75,000 - Design -Rathdrum Combustion Turbine Generator Units 1 and 2 Protection Upgrade

\$50,000 - Design –Monroe Street Hydroelectric Generator Protection Upgrade

2023

\$300,000 Construction -Rathdrum Combustion Turbine Generator Units 1 and 2 Protection Upgrade

\$200,000 Construction –Monroe Street Hydroelectric Generator Protection Upgrade

\$100,000 - Design –Boulder Park Reciprocating Engine Generator Protection Upgrade

2024

\$50,000 - Design –Northeast Combustion Turbine Generator Protection Upgrade

\$200,000 - Construction –Boulder Park Reciprocating Engine Generator Protection Upgrade (2 Units)

2025

\$200,000 - Construction –Boulder Park Reciprocating Engine Generator Protection Upgrade (2 Units)

\$200,000 - Construction –Northeast Combustion Turbine Generator Protection Upgrade

2026

\$200,000 - Construction –Boulder Park Reciprocating Engine Generator Protection Upgrade (2 Units)

Generation Protection Upgrade Program

In addition to reducing the risk of unexpected failure causing unplanned extended outages, the O&M costs test, troubleshoot and maintain relays is expected to be reduced. The interval to electromechanical and solid state relays are 6 years compared to twelve for modern digital multifunctional relays. Additional technician training is required to properly maintain obsolete relays. Upgrading Avista relay packages will create efficiencies associated with standard training and practices.

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 design and construction required to upgrade protection relays require support from multiple stakeholders. Protection upgrade designs will require support from Protection Engineering, SCADA Engineering, and Generation Controls/Electrical Engineering. Construction will require support from the PCM and Electric shops. Outage will need to be coordinate with Power Supply, System Operation, and Hydro/Thermal Operations. Required outages to install the new protection relays will be coordinated with other planned outages whenever possible to limit the impact of construction.

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

Alternative 1 is to replace protection relays at the highest priority sites, Rathdrum Combustion Turbine and Monroe Street HED. The protective systems at these plants are the most difficult to maintain and are a shock hazard during testing. A majority of the other control systems at these plant have been upgrade and the facilities are expected to be part of Avista's power supply portfolio for the foreseeable future.

The main risk of alternative is the potential issues associated with delaying the replacement of relays at Boulder Park Generation Station and Northeast Combustion Turbine. While replacement should be considered to meet the benefits discussed in this narrative, the impact on the delay replacement at these facilities is not as high as RCT and MS HED. NECT has very low running hours per year and BPGS has multiple engines for redundancy. If this alternative is chosen and major capital upgrades are performed at these facilities, protection relay replacement should also be considered.

Alternative 2 is to maintain existing the protection relay. Protection relays will be replaced due to failures. If spare parts are not available, extended outages will required engineer and install new protection relays. The risk of outages at undesirable becomes more likely the longer the aging hardware is in service.

This alternative requires the additional O&M costs to maintain aging protection relays and troubleshoot protection events with limited data. Without event monitoring, the cause of protection event cannot be fully evaluated which increases the risk of restarting a generator without fulling understanding the root cause.

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 design and installation for each generating unit relay replacement is expected to take two years. The project will be sequenced so the first two projects are completed in 2023. The new protection systems will become used and useful to the customers immediately after installation.

-Design for the highest priority project at Rathdrum Combustion Turbine and Monroe Street HED will begin in 2022 with installation to be completed in 2023.

-Boulder Park Generating Station upgrades would align with generator replacements with design in 2023 and installation of two units per year starting in 2024, 2025, and 2026.

Generation Protection Upgrade Program

-Design for Northeast Combustion Turbine would be in 2024 with installation in 2025.

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

By proactively replacing aging protection relays we are able to increase reliability and safety within our generating facilities. This program safely, responsibly, and affordably improves our customers' lives through innovative energy solutions.

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 prudence will be reviewed and re-evaluated throughout the project

Technology has improved and the expectations for protection, monitoring and troubleshooting continue to increase. The installation of modern protection relays will also provide increased visibility into the systems allowing better remote monitoring and troubleshooting. If we do not invest in our protection system, reliability will suffer, maintenance requirements will continue to increase, equipment damage will become riskier, and safety will continue to be an issue.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The following stakeholders will interface with this business case:

- Controls Engineering
- Protection Engineering
- Project Management
- Electric Shop
- Electrical Engineering
- SCADA Engineering
- PCM Shop
- Generation Operations

2.8.2 Identify any related Business Cases

None

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Each project will have a project manager and steering committee for ongoing vetting. The steering committee for each project will consist of the Controls/Electrical Engineering Manager, the Protection Control Meter Technician Foreman, the Protection Engineering Manager, and either the Spokane River Plant Operations Manager, Cabinet Gorge Plant Operations Manager, Noxon Rapids Plant Operations Manager, Lower Spokane River Plant Operations Manager, or Thermal Operations Plant Manager

Generation Protection Upgrade Program

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

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

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

Project decisions will be coordinated by the project manager. The Steering Committee will be advised when necessary. Regular updates will be provided to the Steering Committee by the project manager as project scope, schedule and budget are defined, and through the course of the project execution

Generation Protection Upgrade Program

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the **Generation Protection Upgrade Program** 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:  Date: 7/7/2021

Print Name: Jeremy Winkle
 Title: Controls/Electrical
Engineering Manager
 Role: Business Case Owner

Signature:  Date: 7/8/2021

Print Name: Andy Vickers
 Title: Director of GPSS
 Role: Business Case Sponsor

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

KF_Fuel Yard Equipment_Replacement

EXECUTIVE SUMMARY

The existing system does not allow the plant to operate consistently with safe best practices, environmental stewardship and production. The fuel handling equipment operates at or beyond its absolute limit. In the early 1980's Washington State increased the legal hauling weight and the trucking industry transitioned from 48' trailers to 53' to increase their payload. This change created a number of production and safety challenges for the plant operations and contractor support. The system does not meet current environmental regulations for visibility and particulate matter (PM) emissions for intermittent periods. Although the primary drivers for the project are safety, environmental, and reliability, we do expect a decrease in O&M. With all benefits included, Financial Planning and Analysis has concluded that this is a prudent project. The project will proceed over a two year period with \$12 million in 2019 and \$10 million in 2020. (7/8/2021 Update: *Project timeline has been extended and adjusted and the current plan will continue into 2021 with the underground utilities installed, major equipment purchased and truck dumpers commissioned. 2022 will be construction of conveyance, processing and control buildings and installation of the hog and disc screen.*)

Replacing the major fuel handling equipment will create a safer system for employees and contractors as the new dumpers will be designed to lift current truck lengths and weights. The major equipment will be designed with covers and passive dust control utilizing new dumper technology and conveyance covers. (7/8/2021 Update: *Scope has been reduced to reduce project costs by changing the truck route, eliminating a pass through travel route, reduction of an enclosed processing building, eliminating a conveyor through a more compact layout, eliminating a new power supply from the distribution line near the plant site and delay of replacing the existing #3 fuel conveyor*)

This project will impact customers in service code Electric Direct jurisdiction Allocated North serving our electric customers in Washington and Idaho.

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Greg Wiggins	Initial draft of original business case	05/01/2018	
1.0	Thomas Dempsey	Edit Draft / Executive Summary	07/03/2018	Added content
1.1	Greg Wiggins	Edit Approved Business Case to new Template	07/08/2021	New Template / Update major project changes Scope, Schedule and Budget

KF_Fuel Yard Equipment_Replacement

GENERAL INFORMATION

Requested Spend Amount	\$22,000,000
Requested Spend Time Period	2 year (7/8/2021 Update project will be 5 year)
Requesting Organization/Department	GPSS
Business Case Owner Sponsor	Greg Wiggins Andy Vickers
Sponsor Organization/Department	GPSS
Phase	Execution (7/8/2021 Update project is in execution phase)
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

The major fuel yard equipment being considered for replacement includes the truck dumpers, fuel hog, truck scale, and conveyance systems.

Truck Scale - The truck scale is used to account for the quantity of fuel received from each truck delivery. The truck drivers scale in upon arrival to the site and the scale out after completing the unloading process.

Truck Dumpers - The truck dumper receives the delivered fuel by elevating the trailers. Fuel exits the rear of the trailer into a receiving housing.

Fuel Conveyors - Fuel conveyors move the fuel from the truck dumpers to a metal detection system, then to the fuel hog system and finally out to the fuel yard.

Hog and Disc Screen - The fuel hog is a device that clarifies and conditions the fuel so that it is the proper size required for optimum combustion.

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

There are three key components that comprise the business problem presented by the current fuel yard.

1. Safety
2. Environmental
3. Reliability



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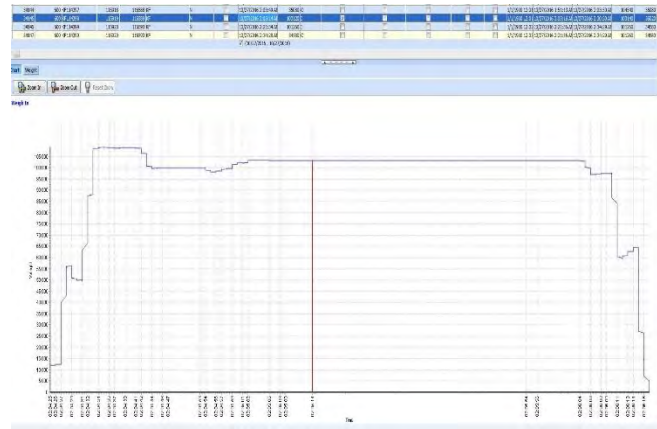
These three components are summarized as follows:

The Kettle Falls Generating Station is a biomass fueled power plant that processes on average 500,000 green tons of waste wood from area sawmills. The wood delivered to the facility is trucked in by contractors utilizing semi-trucks and chip trailer. On average the plant received 65-80 loads of fuel each day with surges to 100 deliveries in a 24 hour period.

The plant's original design was just prior to Washington State increasing the legal haul lengths and weights. All the equipment was designed for 48' trailers and the new law change in 1985 allowed drivers to haul with 53' trailers. When the drivers enter the facility the load is weighed on a State certified scale to determine amount of fuel being delivered. The longer trailers do not completely fit on the scale without the drivers lifting the tag axle on the trailer. The plant's delivery tracking system captures the gross weight of the truck and trailer into the 3Log financial interface application. Through this system vendors and suppliers are paid for their services. Due to the longer trailers and short scale drives can "cheat" the system by not positioning the load correctly on the scale. Each load is reviewed through the 3Log (TWA) Truck Weight Analyzer. When an infraction is found the surveillance video is reviewed and sent to the hauling company for reconciliation. Manual adjustments are made in the system to ensure proper payment to the supplier.



Truck was intentionally positioned short on the scale.



TWA show drivers manipulating the scale due to being overloaded.

The fuel is offloaded truck trailers into the receiving hoppers via a truck dumpers. The wood is then conveyed, screened and sized prior to being transferred out to the fuel inventory pile. The Fuel Equipment Operators then manage the fuel inventory utilizing D10 Cat dozers to stack out incoming fuel and stage inventory to be processed in the plant.

Due to the higher legal hauling limits in Washington the longer truck/trailer configurations require the truck drivers to unhitch the trailer from their trucks. This unhitching process not only increases truck turnaround time and increases hauling costs to plant, it adds a difficult step. Although not the primary factor, a contractor fatality in 2013 occurred while going through this step in the process. One driver was attempting to unhitch his trailer from the truck and was working with another driver to get the hitch pin released when the accident occurred.

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After the load is raised into the air and the fuel is discharged out of the back of the haul trailer into the truck receiving hopper a large plume of dust often launched into the air and then carried in the wind off the plant site. After the wood discharges out of the truck receiving hopper it is transferred via conveyor belt to a disc screen and hammer hog to be properly sized and then discharged onto the hog storage area.

Both Safety and Environmental regulations require that PM be reasonably controlled for worker safety, air quality and visibility. All emissions should be managed on-site.



The fuel yard is subject to a very corrosive environment due to the wet wood being in contact with the equipment. The years of rusting has caused failure to metal conduit and structural steel. The metal support structure of the truck receiving hoppers has rusted through to the point of being completely cracked through. Welded plates have been installed to affected areas on the truck receiving dumpers. Many of the electrical conduits are rusted through and need replacement.

The system is currently running at maximum capacity with fuel spilling over the edges of the conveyance system, the disc screen is not operating at the proper throughput as a significant amount of proper sized fuel is carried over the disc screen into the hammer hog. The over feeding of material into the hog creates excessive wear on the hammer hog grates and hammers.

With an average of 80 semi loads delivered each day and over 25 sawmills depending on the fuel yard at Kettle Falls to be in full operation there is tremendous pressure in keeping the system running. Area mills store the fuel purchased by Avista in storage bins and can only hold the waste wood for a few days and sometimes only hours before the backup of wood begins to cause production issues at the mill. When product flow out of the mill is not managed well suppliers may begin to look for other options to move their waste to

KF_Fuel Yard Equipment_Replacement

more reliable markets. Another important detriment to not keeping fuel moving efficiently is that as more fuel inventory builds at the supplying mill, the resulting Moisture Content increases as well as the opportunity for contamination from rock and other “non-spec” materials. It is important to keep the KFGS fuel yard operating with minimal downtime to provide good service and quality control to the supplier’s milling operations. It is critical to the reliability of both the KFGS plant and its supply chain.

In 2017 a team was assembled including the Thermal Operations and Maintenance Manager, Fuel Manager, Plant Manager, Thermal Engineering and plant staff. The team worked with outside engineering firm WSP to evaluate the fuel yard equipment and explore options. The team also traveled to two new biomass plants to gain knowledge of new equipment and process. This information along with the support of WSP allowed the team to evaluate a number of options.

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**

Major drivers for this project were Asset Condition and Mandatory & Compliance. Installing the new fuel yard equipment with a higher capacity design and environmental dust control measures will be a benefit to the plant and neighbors. Moving truck through the yard quickly reduces trucking costs. This project will decrease truck turn time.

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

The plant experienced a fatality of a contract driver that would have been completely avoided if the truck dumpers were able to lift the current truck weights and lengths. A few years later another driver was injured on plant site attempting to manually offload his overloaded trailer when a bunch of fuel slid out of the trailer and buried the driver crushing his hip and knee. This project will make for a safer facility for our contractors.

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.

Truck weight analyzer and the weighwiz system will be able to accurately capture the delivery with the new longer scales. Truck turntime will decrease as drivers will no longer need to lift tag axels, disconnect the truck and trailer or use one scale for inbound and outbound scaling.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

In 2017 a team was assembled including the Thermal Operations and Maintenance Manager, Fuel Manager, Plant Manager, Thermal Engineering and plant staff. The team worked with outside engineering firm WSP to evaluate the fuel yard equipment and explore options. WSP presented the Team a feasibility study with options to consider. That document is located in the project file.

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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.

The team selected option #3 and in replacing the major equipment in a new layout. Below shows the four options, matrix score, CAPX and OPEX.

This feasibility study includes estimated CAPEX, OPEX and MTC, and discusses the pros and cons of the scenarios analyzed. The possibility of an increase in generation of 15 MW was considered when sizing the equipment. Some equipment drives may require upgrading, as such the equipment was sized for the increase.

Based on extensive in-person meetings with the Avista project team, four scenarios were examined to meet the requirements of the plant; results of the analysis for the scenarios are shown in the table below.

	System #1: Existing and Rebuilds	System #2: Existing Layout c/w new equip	System #3: New Layout c/w new equip	System #4: New System c/w Covered Building
Avista's Ranking Calculator by System	370.00	296.00	123.00	143.00
CAPEX (2017 \$)	\$4.2 M	\$9.5 M	\$21.6 M	\$30.1 M
OPEX (average over 20 years, 2017 \$)	\$1,095,000	\$1,121,000	\$665,000	\$998,000
MTC (average over 20 years, 2017 \$)	\$829,000	\$782,000	\$405,000	\$432,000

2. PROPOSAL AND RECOMMENDED SOLUTION

The four options were discussed and doing nothing has been the approach for a number of years. Maintenance costs have increased with equipment failure to the live bottom gear boxes, dumper cylinders and lifting deck. Modifications are being made to equipment due to obsolete equipment is no longer available. This approach will see continued breakdown maintenance, reduction in fuel yard reliability and continued risks around safety and environmental litigation.

Option 1 includes major rebuild of the existing equipment. The truck dumpers would have mechanical and support rebuilt, some conveyors would be sped up to the maximum allowed throughput, hog and disc screen would be rebuilt, the power distribution, motor control centers and PLC's replaced, all the electrical hardware in the yard would be replaced. This option would not change the operations of the fuel handling system. Safety and environmental concerns would remain unchanged. The truck scaling issue would still remain. The work would create major disruptions to our suppliers as the work and repairs could not be done without interrupting delivery schedules for days and weeks at a time. Fuel would have to be diverted to other consumers with the risk of losing the contracts in the future.

Option 2 included replacing key equipment with one new scale, two dumpers, two conveyors, hog and screen in the existing location. This option would not address the congested truck route that currently exists with one scale. The fuel conveyor angle would remain the same and would not solve the sliding winter fuel issues

KF_Fuel Yard Equipment_Replacement

experienced by the plant operations staff all winter long. This option would disrupt deliveries and cause major fuel disruptions to the sawmills and carriers under contract. Temporary truck dumpers would have to be installed and significant fuel curtailment and diverting would be required.

Recommendation is to pursue Option 3 that includes relocating new equipment to a different location in the fuel yard. This approach would allow the current system to operate while the new system is constructed and commissioned. The layout would reduce crossing traffic issues with the semi trucks. A new longer inbound and separate outbound scales would eliminate the scaling issue as sensors would not allow a driver to scale in unless the truck was positioned correctly on the scale. The two new truck dumpers would be larger in size which would allow the lifting of both the truck and the trailer. This would reduce truck turnaround time and eliminate the hazard identified in the driver fatality. The new dumpers would incorporate a dust containment systems to reduce fugitive dust during the offload. New conveyors would be larger to accommodate higher throughput. The higher capacity belt system would reduce laborious shoveling of spilled fuel. The incline of the new belts would reduce winter frozen fuel from sliding on the conveyor belts. The disc screen would be larger in size for better screening efficiency and reduce hog operation to only oversized material. The upgraded stack out fuel conveyor system would strategically move the fuel to three locations reducing Caterpillar dozer fuel consumption and yearly time base maintenance. A new control tower and power supply would eliminate the electrical deficiencies with the current system.

Option 4 is the same as option 3 with the addition of a covered fuel storage area. Covering the fuel could reduce moisture content during the winter months. Power Supply and Asset Management explored the additional cost benefit and this option did not make financial sense.

Option	Capital Cost	Start	Complete
Existing Rebuild and Minor Upgrades	\$4,200,000	10/2020	6/2023
Existing Layout with New Equipment	\$9,500,000	10/2020	6/2023
New Layout with New Equipment	\$22,000,000	10/2020	6/2023
New Layout with New Equipment and Covered Yard	\$30,100,000	10/2020	6/2023

KF_Fuel Yard Equipment_Replacement

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

The Team worked with WSP and evaluated every component of the fuel handling system. All of the current equipment was ranked using the GPSS project ranking matrix and the scores were used to determine what system would meet the criteria set for the project. Below is an example of the analysis that was done for every part of the fuel handling system.

Avista KFGS Woodyard Study
WSP Ref #: 171-11373-00/185233AEquipment Alternatives and Ranking Table
Date: 10/19/2017

Item #	Equipment Name	Wt	Scope of Work Description & Avista Rating			
			System #1: Existing	System #2: Existing Layout c/w new equip	System #3: New Layout c/w new equip	System #4: New System c/w Covered Building
1	Truck Scale(s)		- maintenance	- new single scale and data recorder	- new dual scales and data recorder	- new dual scales and data recorder
	Personal or public safety	4	3	2	0	0
	Potential environmental issue	4	0	0	0	0
	Regulatory mandate	3	0	0	0	0
	On-going maintenance issue wt:3	3	2	0	0	0
	Decrease future operating costs	2	2	0	0	0
	Increase efficiency (revenues - power usage)	1	1	1	0	0
	Obsolete parts and equipment	1	0	0	0	0
	Risk of equipment failure	4	2	2	0	0
	Customer Value	3	2	1	0	0
	Sub-total		37	20	0	0

Reference key points from external documentation, list any addendums, attachments etc.

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 project will be a two year project with engineering, design and major equipment procurement in the first year followed by construction and commissioning the following year. The breakdown is a two year period with \$12 million in 2019 and \$10 million in 2020. *(7/8/2021 The project will run into 2022 with a possibility of 2023. The project originally requested 22 million over two years, CPG has only funded 20 million. When presenting the request I failed to load the project during the estimating process so AFUDC and Loadings were not added at the time of the request. These two issues have a 4 million shortfall in project funding. During construction the underground excavation process discovered unforeseen challenges with foundations and underground piping that resulted in re-engineering and changes. Cost and overruns from the phase one resulted in the Team drastically cutting scope to manage budget. Changes included re-routing the truck area, removing the enclosed processing building,*

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repurposing some existing equipment, redesigning the layout to eliminate an entire conveyor and postponing replacing the final stackout conveyor.)

(Offsets to projects will be more strongly scrutinized in general rate cases going forward (ref. WUTC Docket No. U-190531 Policy Statement), therefore it is critical that these impacts are thought through in order to support rate recovery.)

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

This project will require some short outages that will be managed within the normal Spring outage for accommodate some conveyor transitions to the current process and power supply connections. There may be some curtailment needs with our contract mill to stop wood deliveries. This project will not cause any plant reliability issues with Power Supply.

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

The project will run into 2022 with a possibility of 2023. The project originally requested 22 million over two years, CPG has only funded 20 million. When presenting the request I failed to load the project during the estimating process so AFUDC and Loadings were not added at the time of the request. These two issues have a 4 million shortfall in project funding. During construction the underground excavation process discovered unforeseen challenges with foundations and underground piping that resulted in re-engineering and changes. Cost and overruns from the phase one resulted in the Team drastically cutting scope to manage budget. Changes included re-routing the truck area, removing the enclosed processing building, repurposing some existing equipment, redesigning the layout to eliminate an entire conveyor and postponing replacing the final stackout conveyor. The Team intentionally stopped work with the contractor Greenberry to reevaluate the costs. The installation was rebid to a number of contractors and a change was made with awarding the work to Knight Construction as a lower cost.

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.

(7/8/2021 Update All of the underground work is complete minus two conveyor foundations that will be installed after the current truck dumpers are demolished. All major equipment is purchased and onsite minus the hammer hog and transition chute and the #3 stack out conveyor. The fueling building is procured and will be installed in September. The truck dumpers will be commissioned mid July. All the critical electrical equipment has been purchased. The project has two options for 2022 one being a complete project to the #3 conveyor and the other a hot feed option which could see some of the equipment in Q3 of 2022 either way. If the hot feed option is selected then the remaining equipment would become operational in 2023.)

KF_Fuel Yard Equipment_Replacement

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

Kettle Falls is a renewable generating site and this project aligns with providing reliable renewable energy to our customers. This project will increase Safety and be good for the environment and neighbors.

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 prudence will be reviewed and re-evaluated throughout the project

This project was subjected to a rigorous evaluation of each major piece of equipment and is documented in the WSP Feasibility Study. The project has worked closely with the Steering Committee that is represented by GPSS, Environmental and Power Supply. The project is being lead by GPSS Project Manager and the Team meets regularly to discuss scope, schedule and budget.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

GPSS Thermal Operations and Maintenance Manager

Environmental

Power Supply

Contracts and Supply Chain

Plant Staff

2.8.2 Identify any related Business Cases

KF 4160 V Station Service replacement (new request in 2022)

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Thomas Dempsey - GPSS Thermal Operations and Maint Mgr

Darrell Soyars – Environmental

Scott Reid – Power Supply

KF_Fuel Yard Equipment_Replacement

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


GPSS Core team will follow the Department Project Management protocol. There will be monthly Steering Committee meetings to discuss issues or concerns. Updates will be shared on an as needed basis between monthly status meetings.

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

Change orders will follow Supply Chain contracting protocol based on financial signing authority.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Kettle Falls Fuel Yard Equipment 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:  Date: 7/8/2021
 Print Name: Greg Wiggins
 Title: Plant Manager
 Role: Business Case Owner

Signature:  Date: 7/9/2021
 Print Name: Andy Vickers
 Title: Director GPSS
 Role: Business Case Sponsor

Signature: _____ Date: _____
 Print Name: _____
 Title: _____

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Role: Steering/Advisory Committee Review

Monroe St Abandoned Penstock Stabilization

EXECUTIVE SUMMARY

The Monroe Street Powerhouse was initially constructed in 1890 and has undergone several modernizations over the last 129 years. During the 1972 modernization, three of the original penstock intakes were plugged with concrete and sealed with a layer of shotcrete. The three 10 ft. diameter steel penstocks were only partially removed, leaving an approximate 250 ft. length of each buried under what is now Huntington Park. It is unknown if the penstocks were also backfilled with material, posing a risk of implosion. These penstocks run underneath parts of the access road, crane staging area, and walking path through the park. The park is open to the public, and the access road and crane areas are critical to maintaining the safe and efficient operation of the Monroe Street Hydroelectric Development. During the 2018 Maintenance Assessment, these penstocks were identified as a high risk due to their location, unknown condition, and observed groundwater.

The recommended solution includes further investigation of the intake dam and penstocks to better quantify the risk, and implementation a plan to mitigate those risks. The scope of this work would likely include an initial engineering evaluation, including investigatory drilling, with stabilization efforts likely to include grouting of the intake and penstock.

The estimated cost of the project is \$900,000. The service code for this program is Electric Direct and the jurisdiction for the project is Allocated North serving our electric customers in Washington and Idaho. Operating Monroe Street 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).

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Ryan Bean	Initial draft of original business case	6/21/2019	
1.0	Ryan Bean	Updated Approval Status	7/2/2019	Full amount approved
2.0	Ryan Bean	5 Year Planning 2020 & New Form	7/8/2020	

Monroe St Abandoned Penstock Stabilization

GENERAL INFORMATION

Requested Spend Amount	\$900,000
Requested Spend Time Period	2 years
Requesting Organization/Department	C07/GPSS
Business Case Owner Sponsor	Ryan Bean Andy Vickers
Sponsor Organization/Department	C07/GPSS
Phase	Initiation
Category	Project
Driver	Failed Plant & Operations

1. BUSINESS PROBLEM

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

The Monroe Street Powerhouse was initially constructed in 1890 and has undergone several modernizations over the last 129 years. During the 1972 modernization, a new turbine intake and penstock arrangement was installed, just prior to Expo '74. During this upgrade, three of the original penstock intakes were plugged with concrete and sealed with a layer of shot-crete. The three 10 ft. diameter steel penstocks were only partially removed, leaving an approximate 250 ft. length of each buried on site. It is unknown if the penstocks were backfilled with material, posing a risk of implosion. The penstocks are located under what is now Huntington Park and run underneath parts of the access road, crane staging area, and walking path through the park.

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.**

The driver for this business case is Failed Plant. The original penstocks are no longer functional and pose a risk to the continued operation of the park and the power plant. Monroe Street supplies year-round base load hydroelectric power to Avista's portfolio. Continuing to operate Monroe Street 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).

Monroe St Abandoned Penstock Stabilization

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

The penstocks are located under what is now Huntington Park and run underneath parts of the access road, crane staging area, and walking path through the park. The park is open to the public, and the access road and crane areas are critical to maintaining the safe and efficient operation of the Monroe Street Hydroelectric Development. During the 2018 Maintenance Assessment, these penstocks were identified as a high risk due to their location, unknown condition, and observed groundwater. Due to the unknown condition of these penstocks, there is a risk of implosion of the abandoned penstocks due to deterioration, potentially resulting in an uncontrolled release of water thereby jeopardizing the plant and the park.

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 investment would field effort in two phases. The first phase would consist of an investigation of the penstocks and original intake dam to determine the condition. The second phase would implement corrective actions to eliminate the risk from implosion and ensure the intake structure is watertight and fit for continued service. The measure of success would be the stabilization of the above components resulting in the mitigation of risk to the public and continued production at the plant.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

See project documentation from 2016 storm water controls and investigation.

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.

The metric supporting the stabilization of the current system is that it is no longer useful and poses a risk to continued operation of the park and plant. During the 2018 Maintenance Assessment, these penstocks were

Monroe St Abandoned Penstock Stabilization

identified as a high risk due to their location, unknown condition, and observed groundwater.

3	Asset Group	Condition Rating	U1
59	Abandoned Penstocks	Poor	0.00
64	Dam Concrete - Original Intake /	Poor	1.2
	Penstock Plugs	Poor	1.2
	Dam Concrete - Seawall / Retaining Wall	Poor	1.2

Option	Capital Cost	Start	Complete
Investigate to ascertain condition; and mitigate leakage or instability if needed.	\$900,000	01 2021	12 2022
Continue to operate at risk.	\$0	01 2021	

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

The failure of the system and risk to the plant is the primary metric for justification of the project. A significant increase in ground water was observed in Huntington Park in 2007 when groundwater was observed to be traveling through the 13.8 kV underground electric vault and into the powerhouse, requiring remediation at the electric vault. Since 2007, excessive groundwater persisted to leak into the powerhouse through cracks in the concrete, and underground conduit penetrations, requiring constant monitoring and controls to be installed to manage the water. In 2015 excessive groundwater was observed to be flooding portions of Huntington Park, requiring areas of the park to be restricted for use. The flooding in Huntington Park increased by a magnitude again in 2016, requiring additional storm water controls and investigation into the source which was determined to be strongly associated with the buried penstocks, validating the drawings indicating the presence of the buried penstocks and associated infrastructure.

Monroe St Abandoned Penstock Stabilization

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 capital cost will be spread out over two years. The first year will be primarily engineering, investigatory drilling, and determination of needed remediation. This is estimated to be \$150,000. The second year will include contractor mobilization and execution of the remediation plan. This is estimated to be \$750,000. This will not offset significant O&M charges because the equipment is no longer in service so it is no longer maintained.

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 execution of this project will temporarily inhibit access to the park and power plant due to investigatory and remediation efforts. The outcome of this project will also answer questions about loading of the access road that would impact future rehabs of the plant.

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

Continue to Operate at risk.: The level of risk is unknown due to the condition of the penstocks being unknown. However, the risk is likely to increase over time due to deterioration of the penstocks and the presence of groundwater in the park. Given the risk to the public, plant operations, and the company's reputation; doing nothing is not advisable.

Investigate and Remediate: This alternative includes further investigation of the intake dam and penstocks to better quantify the risk, and implementation a plan to mitigate those risks. The approach to fix is likely to involve grouting for penstock and intake stabilization, as well as measures for additional water management and monitoring. This alternative would provide a lasting solution to the above concerns and prevent future issues with access and safety.

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 project is expected to take two years. The effort in the first year will be devoted investigation and design. The effort in the second year will consist of

Monroe St Abandoned Penstock Stabilization

execution of a remediation plan. The transfer to plant will be at the end of the second year with the completion of the work.

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

Operating Monroe Street 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). By taking care of this plant we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By executing this project, we ensure that Monroe Street will continue to provide reliable service and mitigate risk to the park and Avista's reputation.

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 prudence will be reviewed and re-evaluated throughout the project

The impacts due to an implosion could harm Avista employees, the public, continued generation from the powerhouse, and Avista's reputation.

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. This includes the creation of a Steering Committee and a formal Project Team. Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance. The Project Manager will manage the project through its conclusion.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The primary stakeholders for this project are, the Hydro Regional Manager on the Upper Spokane, the Upper Spokane plant personnel, GPSS Engineering, Environmental Resources, the City of Spokane and Parks. Other stakeholders may be identified during project initiation.

2.8.2 Identify any related Business Cases

This project will need to be completed prior to any substantial rehab at the Monroe Street power plant, however this is not anticipated to be needed for some time.

Monroe St Abandoned Penstock Stabilization

3.1 Steering Committee or Advisory Group Information

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. A Steering Committee will be formed for this project. The Project Manager will manage the project through its conclusion.

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

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The project will also be executed by a formal Project Team lead by the Project Manager.

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

Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance.

Monroe St Abandoned Penstock Stabilization

The undersigned acknowledge they have reviewed the Cabinet Gorge HVAC 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:	<u> <i>Ryan Bean</i> </u>	Date:	<u> 7/30/20 </u>
Print Name:	<u> Ryan Bean </u>		
Title:	<u> Plant Manager, Upper Spokane </u>		
Role:	<u> Business Case Owner </u>		

Signature:	<u> <i>Andrew Vickers</i> </u>	Date:	<u> 7/31/2020 </u>
Print Name:	<u> Andrew Vickers </u>		
Title:	<u> Director GPSS </u>		
Role:	<u> Business Case Sponsor </u>		

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

Template Version: 05/28/2020

Nine Mile Battery Building

EXECUTIVE SUMMARY

The purpose of this project is to build a battery storage building for the batteries supplying the Nine Mile Falls HED's critical power system to improve reliability and safety. The battery room will be located near the switchyard and underground conduit will be installed to the powerhouse containing power and control cables. During emergency situations, the critical power system is required to continually monitor and control the turbine generators and spillway for safe operations of the river and its flow. The 125 VDC battery banks are the most essential component of the critical power system and the health of the batteries needs to be closely monitored. The existing location batteries on the switchgear floor is susceptible to extreme temperatures that greatly reduce the reliability and performance of the system. The location of the batteries is a safety issue, because they contain hazardous material and expel potentially explosive hydrogen gases during discharge. In addition to the reliability and safety concerns, the structural integrity of the existing floor needs to be reinforced as equipment is added or replaced. A new building with climate control and hydrogen monitoring dedicated to battery storage will greatly enhance the critical power system reliability and eliminate unnecessary safety hazards.

The initial design of the powerhouse has begun as part of the Generation DC Supplied Upgrade program, but the estimated costs are too high to be funded through the program. Therefore, a separate business case is required to complete the design and construction by the end of 2022 before major overhauls to the Units 3 and 4 begin.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	Terri Echegoyen Jeremy Winkle	Original submission	June 2021	

Nine Mile Battery Building

GENERAL INFORMATION

Requested Spend Amount	\$800,000
Requested Spend Time Period	1 year - 2022
Requesting Organization/Department	GPSS
Business Case Owner Sponsor	Jeremy Winkle Andy Vickers
Sponsor Organization/Department	GPSS
Phase	Planning
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

There are a number of issues with the existing location of the batteries in the Nine Mile HED powerhouse including:

- Excessive battery temperature – The batteries are open to the switchgear floor and not enclosed in a climate controlled room. Temperatures above 78 degrees Fahrenheit significantly reduces the usable life and performance of the batteries.
- Hydrogen danger - Batteries emit hydrogen gassing which is extremely explosive in a concentrated area. The existing location of the batteries does not meet current safety standards to monitor and expel potentially explosive hydrogen gases.
- Switchgear floor loading concerns - The existing location of the batteries on the switchgear floor may not be strong enough to safely store new batteries and equipment. During the Units 1 and 2 upgrade, the portions of the switchgear floor had to be strengthened prior to installing new equipment. A thorough structural analysis would need to be completed before installing new critical power equipment in the existing location.
- Battery transportation safety - Batteries contain corrosive acid and great care must be taken when installing and maintaining lead acid batteries. The existing location requires transporting battery up and down multiple levels of the powerhouse and creates safety hazard for electricians and plant personnel.

Nine Mile Battery Building

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

During a utility power failure, the Nine Mile Falls HED facility's critical power system supplies emergency DC power to protect plant equipment and personnel and AC power to control and monitor the generators and auxiliary systems

These systems allow plant operations, during emergency situations, to continue to monitor and control the turbine generators and spillway for safe operations of the river and its flow. Failure of this system during an emergency situation could result in compromised safe operations, cause equipment failure and extended outages. A reliable and safely maintained critical power system benefits the customer by ensuring reliable operations and public safety during an emergency situation.

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

The battery banks are currently located in areas not designed for the storage or operation of batteries, both because of the climate and the floor system. Battery operation and life are hindered by being stored in a location whose temperatures are outside of the recommended range. As isolated systems, when one system experiences a component failure, the remaining battery banks do not have the ability to support the plant. The batteries have an expected life span of 20 years. Excessive temperature above 78 degrees greatly reduces the expected life span of the batteries and hinders performance. Construction of a dedicated battery building similar to that constructed at Cabinet Gorge HED will provide an enclosed space thereby allowing for necessary climate control, monitoring and safe operations.

If this program is not funded or deferred, there will be increasingly negative impacts to the critical power system and continued safety concerns. As the batteries are exposed to high temperatures, their expected lifetime decreases and requires replacement before failure. Emergent replacement of the batteries may cause unplanned outages and strain resources to procure and install new batteries. Since the integrity of the floor is questionable, a detailed analysis and possible improvement would need to be complete before installing new batteries delaying the installation. It would be very likely, the plant would need to operate on a temporary battery system with limited capacity for an extended period of time before replacement negatively impacting operational reliability. The safety concerns associated with hazardous materials, hydrogen gassing, and structural integrity would continue to exist and expose plant personnel to dangers. Funding this business case will eliminate the operational and safety concerns associated with location of the batteries.

Nine Mile Battery Building

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.

Success will be measured through consistent monitoring of the batteries and their environment. In the event of an emergency, the batteries would perform as expected. Load tests would indicate that the expected life span of the batteries is consistent with manufactures specifications.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem

- Battery Temperature Data - Temperature monitoring in 2012 confirmed prolong temperature near or above 85 degrees Fahrenheit.

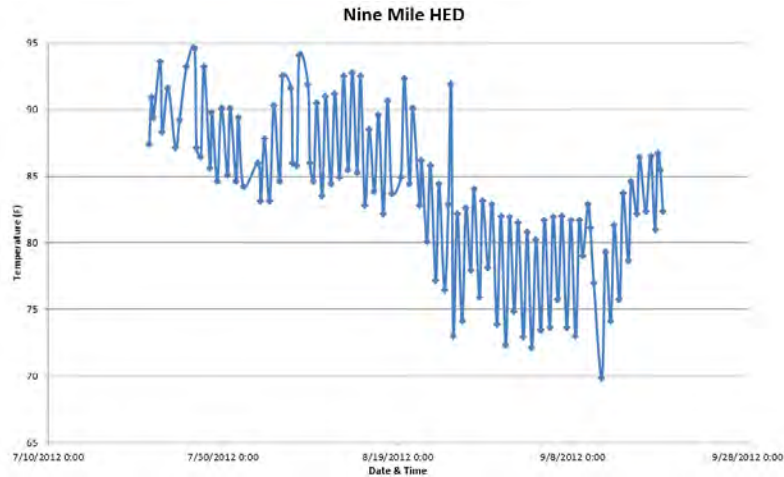


Figure 1-2012 Battery Temperature Monitoring

- Switchgear temperatures are monitored on the PI Historian system. During the late June 2021 heat wave, temperature in the powerhouse reached over 100 degrees Fahrenheit on multiple days. Daily operational logs taken in the morning matched PI Historian temperature of greater than 85 degrees Fahrenheit.

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.

N/A

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
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Nine Mile Battery Building

[Recommended Solution] Dedicated Battery Building	\$800,000	01/2022	12/2022
[Alternative #1] Enclose batteries in existing location	\$950,000	01/2022	12/2022
[Alternative #2] Relocate batteries to plant basement	\$800,000	01/2022	12/2022

The recommend solution is to construct a dedicated battery building near the switchyard. This is the safest solution, because the hazards associated with batteries will no longer be locates in the plant powerhouse.

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

Analysis of the various options took into consideration overall cost, performance projections, ergonomic conditions, heat dissipation, hydrogen dissipation and safety considerations. See attached document for details regarding alternative methods analysis.

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.

Project engineering will continue through 2021. A project within the Generation DC Supplied System Update program already exists (20505079) and will support this work in 2021 with the goal being to solidify designs to be implemented in 2022.

The outcome of this investment is not expected to increase O&M costs. The investment will reduce O&M costs for battery maintenance costs. The new building will greatly reduce the risk of replacing one or multiple batteries.

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 negative safety impacts associated with the current locations of the batteries on plant operations will be eliminated after the successful implementation of this business case. The major safety hazards will be isolated to the dedicated battery room which will be closely monitored and only accessible to necessary personnel. The impact to the operation team will be very positive.

The project will significantly benefit the crew performing battery maintenance. The new battery room will be in a very accessible location to reduce maintenance time. The room will be designed ergonomically to reduce the impact on personnel maintaining and replacing batteries.

Nine Mile Battery Building

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

Alternatives #1 and #2 were eliminated as acceptable solution, because the batteries would still be located in the powerhouse and require disruptive construction in the powerhouse. These solutions would require extended time on temporary critical power. Most importantly, these solutions do not solve the safety risk specifically maintaining the batteries in the powerhouse.

Please see the attached document for additional alternatives analysis information.

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.



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

At Avista, our Mission is to improve our customers' lives through innovative energy solutions – safely, responsibly and affordably. This project will improve battery safety and provide continuous operation in the event of an emergency at Nine Mile Falls HED.

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 prudence will be reviewed and re-evaluated throughout the project

The health of the critical power system is vital to plant operations and safety. Proper battery storage in a temperature controlled environment greatly reduces the risk of battery failure. Additionally, moving the batteries outside the powerhouse reduces the safety risk to plant personnel and potential damage to batteries due to other plant operations.

During project design, construction, and commissioning, the project will be continually evaluated to ensure the goals of the project are being met. Remote room temperature, battery condition and hydrogen monitoring will be utilized to verify the temperature control of the environment. Access to the building will be limited to essential personnel to limit and minimize any safety risks to personnel and equipment. Battery discharge testing and subsequent recharging will also

Nine Mile Battery Building

evaluate the performance of the system prior to project completion and periodically throughout the life the system.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

- GPSS Project Delivery (engineering and project management)
- Spokane River Plant Operations
- Battery Maintenance and Testing
- Spokane River Permitting and Environmental
- Supply Chain (contracts management)
- Power Supply
- Hydro Compliance

2.8.2 Identify any related Business Cases

N/A

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

Steering committee members consist of the Manager of Hydro Operations & Maintenance, the Manager of Spokane River Hydro Operations and the Manager of Controls & Electrical Engineering. The Battery Maintenance & Testing team will serve as an Advisory Group for this project.

Nine Mile Battery Building

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

This project will be governed by the methods described in the GPSS PM Process Flow document. Governance tasks will include monthly project reports, quarterly project updates, business case updates, the monthly monitoring of project costs and schedule, tracking changes, monitoring risks and issues, communications including project meetings and stakeholder communication.

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

The creation and utilization of a Risk Registry will provide for the identification of risks and their analysis. In the event changes are needed, documentation will be presented to the steering committee who is solely authorized to approve said changes.

Nine Mile Battery Building

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Nine Mile Falls HED Battery Room 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:  Date: 7/7/2021

Print Name: Jeremy Winkle
 Title: Controls/Electrical
Engineering Manager
 Role: Business Case Owner

Signature:  Date: 7/12/2021

Print Name: Andy Vickers
 Title: Director of GPSS
 Role: Business Case Sponsor

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

Nine Mile Powerhouse Crane Rehab

EXECUTIVE SUMMARY

The Nine Mile Falls Generator Bay and Access Bay bridge cranes were replaced in 1993 prior to the Units 3 and 4 replacement project. Both cranes are Kone brand 35ton cranes with service class for both cranes being H1 – light duty. The Nine Mile powerhouse cranes are now beyond their useful life. Their duty cycle is too low to support continuous work during future unit overhauls with both replacement controls and mechanical parts no longer supported by the manufacturer and must be custom fabricated. The Generator floor crane trolley is now out of service, limiting Avista’s capability to respond to a turbine generator failure. During the 2018 Maintenance Assessment, the cranes were identified as high risk due to their current condition.

The recommended solution includes replacement of each crane’s hoist and trolley system and installing a modern hoist and trolley. This approach is a modern in-kind replacement of the current powerhouse cranes and would provide a lasting solution to meet current and future crane demands.

The estimated cost of the project is \$1,500,000 in order to rehabilitate both bridge cranes. The service code for this program is Electric Direct and the jurisdiction for the project is Allocated North serving our electric customers in Washington and Idaho. Operating Nine Mile 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).

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Ryan Bean	Initial draft of original business case	7/1/2019	
1.0	Ryan Bean	Updated Approval Status	7/2/2019	Full amount approved
2.0	Ryan Bean	BCFCR Submitted	5/6/2020	Accelerate Funding
3.0	Ryan Bean	5 Year Planning 2020 & New Form	7/8/2020	

GENERAL INFORMATION

Nine Mile Powerhouse Crane Rehab

Requested Spend Amount	\$1,500,000
Requested Spend Time Period	2 years
Requesting Organization/Department	C07/GPSS
Business Case Owner Sponsor	Ryan Bean Bob Weisbeck
Sponsor Organization/Department	C07/GPSS
Phase	Initiation
Category	Project
Driver	Failed Plant & Operations

1. BUSINESS PROBLEM

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

The Nine Mile Falls bridge cranes were replaced in 1993 prior to the Units 3 and 4 replacement project. Both cranes are Kone brand 35ton cranes. Service class for both cranes is H1 – light duty. The light duty means infrequent use in a powerhouse or seldom used warehouse setting.

These cranes are now beyond their useful life. Recent maintenance and deeper investigation have resulted in one crane being removed from service and the other having a finite amount of life left.

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.**

The driver for this business case is Failed Plant. The generator floor crane is no longer available, and the access bay crane has a finite amount of life left placing future repair and refurbishment activities at risk. Nine Mile supplies year-round base load hydroelectric power to Avista's portfolio. Continuing to operate Nine Mile 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).

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

These cranes are critical to repair and refurbishment work necessary to maintain and overhaul generating equipment. Many of the electrical control components of the crane are now obsolete, and retrofitting the with other parts is not possible. Many mechanical parts are no longer produced such that replacement parts

Nine Mile Powerhouse Crane Rehab

must be custom fabricated. If the work is not addressed, this will lead to extended down time due for repairs, increased O&M costs, and impacting schedules of future repair and overhaul work.

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 measure of success would be in restoring the capabilities of the powerhouse cranes. This could be captured in reduced crane downtime, reduced O&M for crane repairs, and decreased risk to future project schedules due to crane failures. With the current generator bay crane trolley out of service, overhauls of any major turbine generator equipment may not be possible at this time.

1.5 Supplemental Information

1.5.1 Please reference and summarize any studies that support the problem.

See Nine Mile Falls HED Bridge Crane Replacement Basis of Design Report

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.

The metric supporting the replacement of the current cranes is that one is no longer functional and other has a finite number of start/stops left. Major repairs to turbine generator equipment may not be feasible and future projects will be impacted without cranes readily available.

During the 2018 Maintenance Assessment, the cranes were identified as high risk due to their current condition.

1	Net Condition Index & Rating Summary		
2			Units
3	Nine Mile Falls HED Asset Group	Condition Rating	U1
69	Crane - Generator Bay 35Ton Kone	Poor	1.666
70	Crane - Access Bay 35Ton Kone	Poor	1.666

Nine Mile Powerhouse Crane Rehab

Option	Capital Cost	Start	Complete
Alternative 2: Replace Hoists, Trolleys, Bridge crane drives and controls	\$1,500,000	01 2023	12 2024
Alternative 1: Replace Crane control system	\$500,000	01 2023	12 2024
Continue to repair current system (O&M)		01 2021	

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

The failure of the system is the primary metric for justification of the project. During the higher usage periods, we have seen issues with various aspects of the cranes, mostly having to do with the controls and electrical systems. During the most recent unit replacement project for Units 1 and 2, the general construction contractor used the crane on an almost constant basis during concrete demolition activities to remove rubbleized concrete from the powerhouse. Numerous instances of thermal overload occurred on the crane due to the high usage, causing work stopped and project delays.

Many of the electrical control components of the crane are now obsolete and retrofitting the with other parts is not possible. Many mechanical parts are no longer produced such that replacement parts must be custom fabricated.

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 capital cost will be spread out over two years. The first year will be primarily design, sourcing, and installation of equipment for the first crane. This is estimated to be \$750,000. The second year will include design, sourcing, and installation of equipment for the first crane. This is estimated to be \$750,000. This will not offset significant O&M charges because the one crane has failed so it is no longer maintained, while the other has minimal inspection and maintenance performed.

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 execution of this project will enable the needed overhaul of Nine Mile Units 3 & 4. The unit controls and many mechanical components are at the end of

Nine Mile Powerhouse Crane Rehab

their useful life. Plant production and reliability will be impacted without the availability of cranes.

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

Do Nothing: This alternative includes doing nothing with the existing cranes. Maintaining them as is without replacing any electrical or mechanical components. This would include the continual maintenance and/or replacement of parts, where possible. This will lead to continued periods of crane down-time for necessary repairs or part replacements. It will also maintain the thermal overload issue that we have been experiencing during high levels of use.

The approximate capital cost to this alternative is \$0 initially. However, future costs could be substantial if crane down time causes delays during maintenance or Unit overhaul projects. These future costs are anticipated to be all O&M costs related to maintaining the crane as necessary.

Alternative 1: Replace crane control system. This alternative would include removing the existing control system on the two bridge cranes and replacing them with a modern Magnatek VFD control system. This alternative would ensure that the control system is robust and reliable, however would not address the thermal overload issues with extended use, nor the custom mechanical parts needed for each repair.

Alternative 2: Preferred Alternative: Replace Hoists, Trolley's, Bridge crane drives and controls. This alternative would include replacing each crane's hoist and trolley system and installing a modern hoist and trolley. This alternative also includes replacement of the controls system with the Magnatek system discussed in Alternative 1. This would include Hoist VFD controls, VFD controls on the hoist trolley and a new bridge panel with VFD controls that will hook to the current end truck motors. This option is a modern in-kind replacement of the current powerhouse cranes and would provide a lasting solution to meet current and future crane demands.

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 project is expected to take two years. The effort in the first year will be devoted design, equipment sourcing, and replacement of the first crane. The effort in the second year will consist of equipment sourcing and replacement of the second crane. The transfer to plant will be at the end of each year with the completion of commissioning of each crane.

Nine Mile Powerhouse Crane Rehab

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

Operating Nine Mile 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). By taking care of this plant we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By executing this project, we ensure that Nine Mile will continue to provide reliable service and mitigate risk to future projects and fielding unplanned failures.

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 prudence will be reviewed and re-evaluated throughout the project

Industrial cranes of this size and complexity fall into this range of cost. We are currently operating at risk with our units in not being able to respond to failed turbine generator equipment in a timely manner thereby, incurring substantial lost generation and O&M.

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. This includes the creation of a Steering Committee and a formal Project Team. Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance. The Project Manager will manage the project through its conclusion.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The primary stakeholders for this project are, the Hydro Regional Manager on the Upper Spokane, the Upper Spokane plant personnel, GPSS Engineering, GPSS Construction and Maintenance, and Power Supply. Other stakeholders may be identified during project initiation.

2.8.2 Identify any related Business Cases

This project will need to be completed prior to overhaul of Units 3 & 4, or any repairs to any major equipment on the generator floor.

Nine Mile Powerhouse Crane Rehab

3.1 Steering Committee or Advisory Group Information

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. A Steering Committee will be formed for this project. The Project Manager will manage the project through its conclusion.

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

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The project will also be executed by a formal Project Team lead by the Project Manager.

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

Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance.

Nine Mile Powerhouse Crane Rehab

The undersigned acknowledge they have reviewed the Cabinet Gorge HVAC 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: *Ryan Bean* Date: 7/30/20
 Print Name: Ryan Bean
 Title: Plant Manager, Upper Spokane
 Role: Business Case Owner

Signature: *Andrew Vickers* Date: 7/31/2020
 Print Name: Andy Vickers
 Title: Director, GPSS
 Role: Business Case Sponsor

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

Template Version: 05/28/2020

Nine Mile Units 3 & 4 Control Upgrade

EXECUTIVE SUMMARY

Nine Mile Units 3 and 4 controls were installed in the early 1990's and are at the end of their intended life and there is an increased likelihood of forced outages and subsequent loss of revenue and reliability. A controls upgrade including speed controllers (governors), voltage controls (automatic voltage regulator a.k.a. AVR), primary unit control system (i.e. PLC), and the protective relay system is needed on units 3 and 4. During the 2018 Maintenance Assessment, the Unit controls were rated in poor condition and high in risk due their age and current condition. Upgrading the controls, monitoring, and protection will reduce unplanned outages. The cost of the solution is estimated to be about \$1,000,000 per unit at this time. This solution will address issues of obsolescence, increased likelihood of unplanned outages, and performance needs to work with the new dynamics of modern systems. 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.

VERSION HISTORY

Version	Author	Description	Date	Notes
<i>1.0</i>	<i>Kristina Newhouse</i>	<i>Initial draft to convert to new template</i>	<i>7/2/2020</i>	<i>Existing Business Case. Executive summary only</i>
<i>2.0</i>	<i>Kristina Newhouse</i>	<i>Complete remaining template</i>	<i>7/31/2020</i>	<i>Remaining sections 1, 2, & 3.</i>

Nine Mile Units 3 & 4 Control Upgrade

GENERAL INFORMATION

Requested Spend Amount	\$2,000,000
Requested Spend Time Period	2 years
Requesting Organization/Department	Generation Production and Substation Support
Business Case Owner Sponsor	Kristina Newhouse Andy Vickers
Sponsor Organization/Department	Generation Production and Substation Support
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

The problem is that Nine Mile Units 3 and 4 controls are obsolete, unsupported and in overall poor condition. Upgrading the speed controllers (governors), voltage controls (automatic voltage regulator a.k.a. AVR), primary unit control system (i.e. PLC), and the protective relay system will address issues of obsolescence, increased likelihood of unplanned outages, and performance needs to work with the new dynamics of modern systems.

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

The major driver of this business case is Asset Condition. There have been unit outages that were specifically taken to address problems associated with the existing control and protection equipment. Problems with the governor and wicket gate actuating mechanisms continue to affect unit reliability. The current governor system is undersized to handle the required load; causing startup and speed control issues. Customers benefit in that it will allow Avista to economically optimize an existing asset to provide energy and other energy related products.

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

During the 2018 Maintenance Assessment, the Unit controls were rated in poor condition and high in risk due their age and current condition. 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.

Nine Mile Units 3 & 4 Control Upgrade

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.

A successful investment to upgrade the Nine Mile 3 & 4 Control Monitoring, and Protection systems would be measurable by Future Maintenance Assessments that would show an improved condition and reduction in risk.

1.5 Supplemental Information

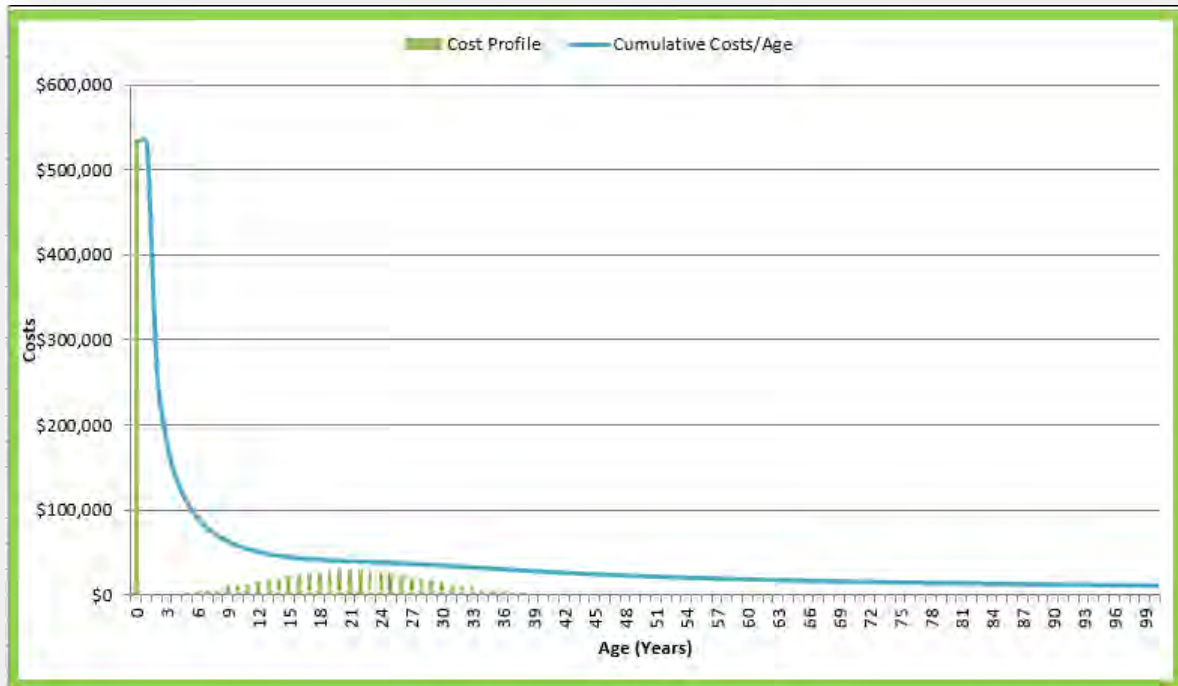
1.5.1 Please reference and summarize any studies that support the problem

The following files from the 2018 Maintenance Assessment can be found at (c01m114) G:\Generation\Asset Management\GPSS Condition Assessment Forms and References\Condition Assessment - NM

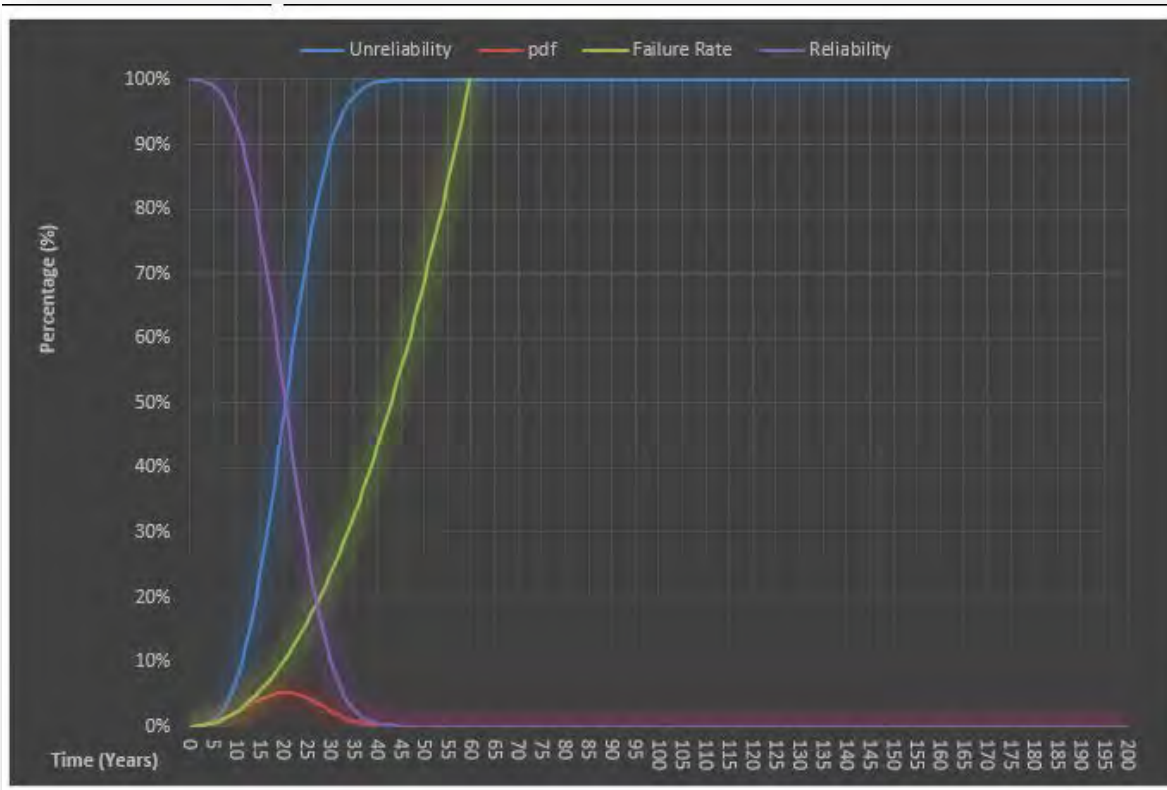
- Nine Mile Hydro AMP 041912.xlsx file
- NM Lifecycle Cost Calculator 061918.xlsx

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.

The following graphs illustrate the Lifecycle Cost Analysis that was done as part of the 2018 Maintenance Assessment.



Nine Mile Units 3 & 4 Control Upgrade



2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
<i>[Recommended Solution] Replace Unit Control, Monitoring, and Protection Systems</i>	<i>\$2M</i>	<i>01 2024</i>	<i>12 2026</i>
<i>[Alternative #1] Do Nothing</i>	<i>\$0M</i>		

The recommended solution is to 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.

Nine Mile Units 3 & 4 Control Upgrade

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

The 2018 Maintenance Assessment was considered in preparing this capital request (see section 1.5.)

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). Include any known or estimated reductions to O&M as a result of this investment.

[Offsets to projects will be more strongly scrutinized in general rate cases going forward (*ref. WUTC Docket No. U-190531 Policy Statement*), therefore it is critical that these impacts are thought through in order to support rate recovery.]

The requested capital costs will cover design, material, factory acceptance testing, installation, and commissioning. 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 objective is to ensure system compatibility with current standards and improve system reliability.

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

Resources will need to be allocated by each stakeholder listed in 2.8.1 for the project to be carried out from initiation to completion.

This project will benefit Power Supply and System Operations as they are responsible for dispatching power from Cabinet Gorge plant to meet contractual obligations and managing the day-to-day transmission system operational requirements. It will also benefit engineering and the shops as they are responsible for providing maintenance and support with the generating facilities.

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

While the generator is capable of producing energy with existing systems, 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.

No other options were considered due to the extensive age of the various systems and the difficulty to upgrade only a portion of the technology as new technology is incompatible with the obsolete technology.

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 business case will include 2 projects, one for Unit 1 and another for Unit 2.

Design and Construction for each project take place on consecutive years.

2024 – Design Unit 1

2025 – (First half of the year) Install Unit 1, transfer to plant
(Second half of the year) Design Unit 2

2026 – Install Unit 2, transfer to plant

Nine Mile Units 3 & 4 Control Upgrade

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

Replacing obsolete and problematic control equipment on unit 3 and unit 4 will increase reliability and efficiencies at Nine Mile HED. This program safely, responsibly, and affordably improves our customers' lives through innovative energy solutions.

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 prudence will be reviewed and re-evaluated throughout the project

We cannot continue to operate units 3 and 4 at Nine Mile HED and expect the same results as when the controls were installed over 20 years ago. Technology has improved and the expectations for automation and monitoring continue to increase. The installation of new controls and protection will also provide increased visibility into the systems allowing better remote monitoring and troubleshooting. If we do not invest and take care of these two units, they will continue to be unreliable and fall further behind in technology that other upgraded units operate with.

2.8 Supplemental Information

2.8.1 Identify customers and stakeholders that interface with the business case

The following stakeholders will interface with this business case:

- Controls Engineering
- Electrical Engineering
- Mechanical Engineering
- Protection Engineering
- SCADA Engineering
- Project Management
- PCM Shop
- Electric Shop
- Mechanic Shop
- Hydro Operations

Nine Mile Units 3 & 4 Control Upgrade

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

The project will have a project manager and steering committee for ongoing vetting. The steering committee will minimally consist of the Controls Engineering Manager, the Electrical Engineering Manager, The Mechanical Engineering Manager, The protection Engineering Manager, the Protection Control Meter Technician Foreman, and the Spokane River Plant and Operations Manager.

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

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

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

Project decisions will be coordinated by the project manager. The Steering Committee will be advised when necessary. Regular updates will be provided to the Steering Committee by the project manager as project scope, schedule and budget are defined, and through the course of the project execution.

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the [Nine Mile Unit 3 & 4 Control Upgrade](#) 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:	<i>Kristina Newhouse</i>	Date:	8/3/2020
Print Name:	Kristina Newhouse		
Title:	Controls Engineering Manager		
Role:	Business Case Owner		

Signature:	<i>Andrew Vickers</i>	Date:	8/3/2020
Print Name:	Andy Vickers		
Title:	Director of GPSS		
Role:	Business Case Sponsor		

Nine Mile Units 3 & 4 Control Upgrade

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

Template Version: 05/28/2020

Noxon Rapids HVAC

EXECUTIVE SUMMARY

The current ventilation system in the powerhouse at the Noxon Rapids Hydroelectric Development is not operational. The system was installed in 1959 and parts are no longer available. The system needs to be replaced because the original ventilation system controls are no longer functional and have been removed. There is no cooling or heating capacity with the current ventilation system and the current air handling system can only be operated manually for ventilating and exhausting powerhouse air. There is no filter system for plant make up air which results in outside smoke from wildfires and dust in the outside air from entering the plant. Additional transformers and electrical equipment planned to be installed within the powerhouse over the next 7 years will significantly increase internal plant heat loading.

To be able to support a satisfactory work environment for plant personnel and enable sufficient cooling for critical electrical equipment, the Noxon Rapids powerhouse needs to have a new HVAC System with significant cooling and heating capacity. 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. Operating Noxon Rapids 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).

Noxon Rapids has significant operational flexibility and continues to supply clean, reliable, and cost-effective energy for Avista customers. The capacity of Noxon Rapids is 565 MW. The estimated cost of the project is \$1.5 Million, and it is critical that this project is completed prior to the completion of the planned Noxon Rapids Generator excitation upgrade which is expected to be completed within the next 7 years. This new HVAC system will provide the needed plant cooling of this new equipment and provide sufficient heating, filtered ventilation and air conditioning in support of normal operations of the plant. Without this system replacement, plant personnel will be subjected to unacceptably high internal powerhouse temperatures and critical electrical equipment will fail due to inadequate cooling.

Noxon Rapids HVAC

VERSION HISTORY

Version	Author	Description	Date	Notes
Draft	Alan Lackner	Initial draft of original business case	07/06/2021	
1.0	Alan Lackner	Updated for 2022-2026 Capital budget	07/07/2021	Not yet approved

GENERAL INFORMATION

Requested Spend Amount	\$ 1,250,000
Requested Spend Time Period	2 years
Requesting Organization/Department	LO7? GPSS
Business Case Owner Sponsor	Alan Lackner Andy Vickers
Sponsor Organization/Department	AO7/GPSS
Phase	Initiation
Category	Project
Driver	Failed Plant & Operations

Noxon Rapids HVAC

1. BUSINESS PROBLEM

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

The HVAC system at Noxon Rapids no longer functions. The 1959 heat pump has been removed due to catastrophic failure. New electrical upgrades to the generator excitation systems will introduce a significant heat load. Without a new system the temperature in the plant will exceed acceptable temperatures for operational personnel and critical electrical equipment.

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

The driver for this business case is Failed Plant. The heating and ventilation system is no longer functional. A new HVAC system will support the loads of critical upgrades to the electrical system, improve the working conditions of the powerhouse with filtered air and temperature control and enable the plant to function effectively into the future. Noxon Rapids has operational flexibility and is operated to support energy supply, peaking power, provide continuous and automatic adjustment of output to match changing loads, and other types of services necessary to provide a stable electric grid and to maximize value to Avista and its customers

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

There is no cooling or heating capacity with the current ventilation system and the current air handling system can only be operated manually for ventilating and exhausting powerhouse air. There is no filter system for plant make up air which results in outside smoke from wildfires and dust in the outside air from entering the plant. Planned electrical upgrades are likely to result in heat that will cause electronic equipment to fail.

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 HVAC system will be designed to heat and cool the plant to adequate working temperature for plant personnel. The system will also be designed to adequately filter outside air to protect personal and equipment from outside contaminants. In addition, the system will be designed to compensate for the heat load of existing and proposed critical electrical equipment. These types of systems exist in other similar facilities. The measure of success will be air quality and temperature control inside the powerhouse.

Noxon Rapids HVAC

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.**

The metric supporting the replacement of the current system is that it is no longer functional. Air intake and exhaust are now performed manually. Make up air is not filtered allowing outside contaminants such as smoke and dust to enter the powerhouse. Internal temperature of the plant is not controlled effectively. The introduction of new electrical equipment which will significantly increase the heat load, will only make the problem worse.

2. PROPOSAL AND RECOMMENDED SOLUTION

Option	Capital Cost	Start	Complete
Replace System	<i>1,250,000</i>	<i>01/2023</i>	<i>12/2024</i>
<i>Do Nothing</i>	<i>0</i>	<i>01/2018</i>	

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

The failure of the system is the primary metric for justification of the project. The current system is not adequate to prevent contaminants from entering the plant, is manually controlled, does not adequately control internal plant temperature, and will not support critical plant electrical upgrades due to the increased heat load. Without a proper HVAC system, operation of the plant will be put at risk due to unacceptable working conditions for operational personnel and risk to critical electrical equipment overheating.

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 because of this investment.

The capital cost will be spread out over two years. The first year will be primarily design. This is estimated to be \$250,000. The second year will include equipment purchase, equipment removal, new equipment installation and commissioning. This is estimated to be \$1,000,000. This will not offset significant O&M charges because the equipment has failed so it is no longer maintained. The risk is to personnel due to the lack of air quality control and powerhouse temperature control and the risk to critical electrical equipment.

Noxon Rapids HVAC

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 execution of this project will enable the needed upgrade of the Noxon Rapids generator excitation replacement project. The Excitation system at the end of its useful life. The generators cannot function without this critical system. This critical plant systems will be at risk without adequate cooling. The temperature in the plant and inadequate air quality is also no longer be acceptable.

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

Repair of the existing system is not possible.

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.

This project is expected to take two years. The effort in the first year will be devoted system design and engineering. The effort in the second year will consist of equipment purchase, equipment removal, new equipment installation and system commissioning. The transfer to plant will be at the end of the second year with the completion of commissioning.

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

Noxon Rapids affordably supports the power needs of our company and our customers. It also assists Avista in obtaining stated green energy goals. By taking care of this plant we support our mission of improving our customer's lives through innovative energy solutions which includes hydroelectric generation. By executing this project, we ensure that Noxon Rapids is performing at a high level and serving our customers with clean, 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 prudence will be reviewed and re-evaluated throughout the project

2.8 Supplemental Information

Noxon Rapids HVAC

2.8.1 Identify customers and stakeholders that interface with the business case

The primary stakeholders for this project are, the Plant Manager at Noxon Rapids, Noxon Rapids Plant personnel, GPSS Engineering, GPSS Construction and Maintenance, Power Supply, Environmental Resources. Other stakeholders may be identified during project initiation.

2.8.2 Identify any related Business Cases

No current business cases.

3. MONITOR AND CONTROL

3.1 Steering Committee or Advisory Group Information

A formal Project Manager will be assigned to a project of this size. The project will be managed within project management practices adopted by the Generation Production and Substation Support (GPSS) department. A Steering Committee will be formed for this project. The Project Manager will manage the project through its conclusion.

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

Management of this project will include the creation of a Steering Committee which will include managers representing the key stakeholders involved in this project. The project will also be executed by a formal Project Team lead by the Project Manager.

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

Once the project is initiated, reporting on scope, schedule and cost will occur monthly. Changes in scope, schedule, or cost will be surfaced by the Project Manager to the Steering Committee for governance.

Noxon Rapids HVAC

4. APPROVAL AND AUTHORIZATION

The undersigned acknowledge they have reviewed the Noxon Rapids HVAC 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:  Date: 07/07/2021

Print Name: Alan Lackner
 Title: Noxon Rapids Plant Manager
 Role: Business Case Owner

Signature:  Date: 7/7/2021

Print Name: Andy Vickers
 Title: Director GPSS
 Role: Business Case Sponsor

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

Post Falls – North Channel Spillway Refurbishment

EXECUTIVE SUMMARY

The major driver for this business case is asset condition. The North Channel spillway at Post Falls is comprised of 9 total spillgates – one large rolling sector gate and 8 tainter style radial gates. The North Channel spillway is a critical asset to Post Falls, being that it is a main spillway to divert water downstream once plant capacity is reached. The North Channel spillway continues to show its age, with continuing concrete deterioration, failing mechanical gate hoist equipment, and gate issues. Seepage through the left abutment has also been monitored by the Dam Safety team for years. In addition to normal maintenance activities, the North Channel Dam has undergone several major projects since the 1990's in an attempt to keep it functional and reliable. These have included at least two grouting projects to attempt to improve the internal integrity of the primary dam. The large sector gate has been structurally modified to address its design deficiencies and the tainter gates have been painted, and lift mechanisms have been refurbished. However, with all of these efforts, the current condition of the 110+ year old structure raises questions about its reliability to continue to provide the functions needed at the site.

The recommended solution is to Replace the Sector Gate, Tainter gates, gate lifting mechanisms, and perform extensive concrete repair work. Update gate controls and repair or replace embedded components. The replacement gates could be like-kind replacements or could be a more modern gate design, such as vertical rolling wheel gates or an inflatable gate. Extensive concrete work will be required regardless of the gate type due to the condition of the current concrete, up to and including full replacement of the spillway piers and spillway ogee. Additional concrete work would be necessary if a new gate design were chosen to replace the existing gates. This project is estimated to cost \$21,000,000 +/-30% depending on the chosen scope and scale of the project. Should this project continue to be delayed, any unplanned failure of this structure could be a serious and costly unplanned contingency in the Powerhouse Redevelopment. Of even more criticality is the impact to upstream, downstream, and aesthetics required of the project. Avista's river license could be affected and our relationship with state and federal regulators would be in jeopardy should a portion of the spillway fail.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	<i>PJ Henscheid</i>	<i>Format existing BC into exec summary</i>	<i>7.6.20</i>	<i>5-year Capital Planning Process</i>
2.0	<i>PJ Henscheid</i>	<i>Completion of full BCJN document</i>	<i>8.3.20</i>	<i>5-year Capital Planning Process</i>

Post Falls – North Channel Spillway Refurbishment

GENERAL INFORMATION

Requested Spend Amount	\$21,000,000
Requested Spend Time Period	3 years
Requesting Organization/Department	J07/GPSS
Business Case Owner Sponsor	PJ Henscheid Andy Vickers
Sponsor Organization/Department	A07/GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

The North Channel spillway at Post Falls is comprised of 9 total spillgates – one large rolling sector gate and 8 tainter style radial gates. The North Channel spillway is a critical asset to Post Falls, as it is a main spillway used divert water downstream once plant capacity is reached. The South Channel spillway is generally only used during high spring runoff flows due to its low capacity and its proximity to Q'emiln Park and boat launch. The North Channel spillway continues to show its age, with progressing concrete deterioration, failing mechanical gate hoist equipment, and gate issues. Prior to spring run-off of 2019, one of the gates' mechanical gear drives was irreparably damaged due, in part, to age of the gear train. The concrete condition is continuing to decline with large localized spalls, leaking lift lines and construction joints.

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**

The major driver for this business case is asset condition. Improving the reliability and functionality of the gates will allow Avista to achieve, more reliably, it's river license requirements related to water flow from Post Falls HED

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

The North Channel spillway will be critical to the success of the Post Falls

Post Falls – North Channel Spillway Refurbishment

Powerhouse Redevelopment, as likely all river flows for the duration of the project (up to two years) will be required to pass through it. Should a portion of the North Channel spillway fail to operate as needed during the powerhouse redevelopment project, there would be no certain way to pass flows and could result in uncontrolled flows over any one of the three dams (uncontrolled releases of water), flooding in Lake Coeur d'Alene, or a combination there-of.

In addition to normal maintenance activities, the North Channel Dam has undergone several major projects since the 1990's to keep it functional and reliable. These have included at least two grouting projects to attempt to improve the internal integrity of the primary dam. The large sector gate has been structurally modified to address some design deficiencies. The tainter gates have been painted, and lift mechanisms have been refurbished. However, with all of these efforts, the current condition of the 110+ year old structure raises questions about its reliability to continue to provide the functions needed at the site. The gate lift mechanism are mechanically failing - the most recent failure mentioned above. The concrete supporting the eight tainter gates is also cracking due to loading where the gates pivot.

The work completed in 2016 on the South Channel Dam rehabilitation clearly showed voids and leakage paths in the concrete, which drives a similar concern of the North Channel Dams' concrete condition below the surface. These are just some of concerns about the ability of the North Channel Dam to continue to operate reliably in the near term (10 to 20 years) unless a significant effort to address some of these concerns is undertaken.

Any unplanned failure of this structure could be a serious and costly unplanned contingency in the Powerhouse Redevelopment. Of even more criticality is an unplanned failure of this structure can significantly impact the operation of the project to provide the upstream, downstream, and aesthetics required of the project - the "Reputational Risk".

Post Falls – North Channel Spillway Refurbishment

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.

Successful completion of the North Channel Powerhouse Rehabilitation without issues related to flow would signify success. Also, more reliable and accurate gate operations at the North Channel, effective gate sealing, and reduced maintenance costs related to the concrete or gates would also signify success. Avista's federal and state regulators charge the company with maintaining to water conveyance features at it's hydro facilities to ensure safety for both the public and the companies employees. Ensuring the spillways are fully functional and reliable not only allows for ease of use, but also helps ensure that we maintain the safety of the public, both upstreama and downstream, of our facilities.

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.

		Tainter Gate 1	Tainter Gate 2	Tainter Gate 3	Tainter Gate 4	Tainter Gate 5	Tainter Gate 6
Spillgates - N.Channel Tainter Gates	Marginal	5.17	5.17	5.17	6.17	5.17	5.17
Gates	Fair	6.67	6.67	6.67	6.67	6.67	6.67
Hoists	Marginal	4.17	4.17	4.17	6.17	4.17	4.17
		Sector Gate					
Spillgates - N.Channel Sector Gate	Marginal	5.17					
Gates		6.67					
Hoists		4.17					

Dam Concrete - N.Channel	Poor	1.0
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The above table is from the Net Condition Index and Rating summary. This information was compiled during the maintenance assessment of all Hydro assets performed in 2018. As shown, the condition of spillgates and hoists are rated as Fair to Marginal. However, the concrete was rated as Poor, and this concrete serves to withstand the hydrostatic force of the water on both the concrete and gates.

Post Falls – North Channel Spillway Refurbishment

The recommended solution is to Replace the Sector Gate, Tainter gates, gate lifting mechanisms, and perform extensive concrete repair work. Update gate controls and repair or replace embedded components. The replacement gates could be like-kind replacements or could be a more modern gate design, such as vertical rolling wheel gates or an inflatable gate. Extensive concrete work will be required regardless of the gate type due to the condition of the current concrete, up to and including full replacement of the spillway piers and spillway ogee. Additional concrete work would be necessary if a new gate design were chosen to replace the existing gates. This could include intermediate concrete piers, added or lowered height to the existing piers, or other. The embedded components (gate slots, guides and sills) will be refurbished if not replaced during the project pending their as-found condition and the gate replacement type.

This alternative will allow for reliable ongoing operation of the spillgate gates, and will provide more versatility and usefulness to the spillway.

Option	Capital Cost	Start	Complete
Replace Sector Gate, Tainter gates, gate lifting mechanisms, and perform extensive concrete repair work. Update gate controls and repair or replace embedded components.	<i>\$21,000,000</i>	<i>01/2022</i>	<i>12/2024</i>
Alternative 1: Refurbish concrete and gates only	<i>\$5,000,000</i>	<i>01/2022</i>	<i>12/2023</i>
Alternative 2: Do Nothing	<i>\$0</i>	<i>N/A</i>	<i>N/A</i>

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

The work that was performed on the South Channel dam in 2016 informed a large amount of the request due the extent of the work that was required. The concrete at the north channel is the same vintage as that of the south channel, and we know the level of degradation it exhibited. Reviewing past maintenance records and maintenance projects also informed the request.

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.

2022 – \$1,500,000 to perform engineering assessment and initiate design work

2023 – \$9,500,000 to perform construction activities on-site. Unsure what will be TTP due to the unknowns related to the scope.

2024 – \$10,000,000 to finalize construction activities. Again, unsure what will be TTP due to the unknowns related to the scope. However, all of the project is anticipated to TTP in 2024.

Post Falls – North Channel Spillway Refurbishment

The project activities should result in a reduction in O&M costs related to the spillway concrete, gates, and gate operating mechanisms by replacing antiquated and underdesigned equipment as well as fully repairing concrete degradation.

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 main business functions that will be impacted by this business case will be Plant Operations and Power Supply.

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

Alternative 1: Refurbish Concrete and Gates Only

This alternative entails a spillway assessment to determine the extent of the deterioration, and draft a refurbishment plan. It would include some concrete work as necessary to ensure continued use of the gates. This would likely take the form of a major injection grouting program as well as localized extensive structural concrete repairs where necessary.

This alternative would include some refurbishment of the sector and tainter gates, to the extent of strengthening members where possible. It would not address the embedded components, nor will it address the mechanical hoist equipment age or the gate controls.

The major risk with this alternative is not addressing the need for continued reliability and functionality during and after the Post Falls Powerhouse Redevelopment. Other risks include challenges with refurbishing gates and concrete that are approaching 100 years old as well as the unknowns of the extent of the refurbishment needed.

Alternative 2: Do Nothing

This alternative would not allow for addressing the concerns with the current condition of the spillway concrete or the gate operating mechanisms. This alternative will require continued and likely increased O&M costs as the gates continue to age.

The major risk associated with this alternative is the unreliable operation and high risks should a structural member(s) fail and prevent the gate(s) from being operated, the mechanical drives fail, or the condition of the concrete continue to deteriorate.

Post Falls – North Channel Spillway Refurbishment

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 alternative is anticipated to begin in 2022, with an engineering assessment of design alternatives and possible design commencement that same year. Construction would start as soon as early summer of 2023, and anticipated transfer to plant in 2024, in time to support the Powerhouse Redevelopment project. However, the overall extent of the scope and overall project cost will fall out of the assessment and alternative selection. This will be a key component to the successful completion of the project and fixing the issues with the aging and degrading spillway.

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

This project will be highly important to the continued reliable and efficient operation of our Post Falls facility, and the Spokane River project. It will also help us maintain our relationships with our regulators and successfully implement our Spokane River license. Safe passage of water downstream through the facility, ensuring safety of not only plant personnel but that of the general public is of the utmost concern. The project will focus of the people responsible the delivering with a strong emphasis on performance. This nature of the project demands a collaborative environment with the wide array of key stakeholder groups.

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 prudence will be reviewed and re-evaluated throughout the project

The project budget and total cost will be regularly reviewed with the project steering committee, as well as, receive approvals as described below for any changes in scope and cost. Prudence is also measured by remaining in compliance the FERC License and Spokane River license such that we can continue to operate Spokane River 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

- GPSS Engineering; Civil, Dam Safety
- Hydro Operations
- Environmental, Permitting, and Licensing
- Master Scheduler

Post Falls – North Channel Spillway Refurbishment

- Asset Management
- Project Accounting, Finance, and Rates
- Supply Chain and Legal
- Corporate Communications
- Construction Inspection and Project Management

2.8.2 Identify any related Business Cases

This project has no other relevant business cases

3.1 Steering Committee or Advisory Group Information

This steering committee for this project will be comprised of individuals from the GPSS, Environmental, and Power Supply departments

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

The project will be led by the core project team. Any changes to scope, schedule and budget will be submitted for approval to the steering committee.

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

The project is utilizing the Project Change Log to track and manage all Project Change Requests (PCR) associated with the delivery of the construction project. The PCR describes the need for change, supplemental documentation, related project artifacts, change order proposals, and any other pertinent information. PCR's are then signed for approval by the project approval thresholds, and then processed against the project risk registry, and or contract amendment with the contractor.

Post Falls – North Channel Spillway Refurbishment

The undersigned acknowledge they have reviewed the Post Falls North Channel Spillway Refurbishment 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:



Date:

8/3/20

Print Name:

PJ Henscheid

Title:

Mgr, Civil and Mechanical Engr

Role:

Business Case Owner

Signature:



Date:

8/3/2020

Print Name:

Andy Vickers

Title:

Director, GPSS

Role:

Business Case Sponsor

Signature:

Date:

Print Name:

Title:

Role:

Steering/Advisory Committee Review

Template Version: 05/28/2020

Upper Falls – Trash Rake Replacement

EXECUTIVE SUMMARY

The trash rake has, since its installation, presented an environmental risk due to the hydraulic system that utilizes to function. When in use, the hydraulic system is suspended over the Upper Fall unit intake and the Spokane River. Should a hydraulic line fail during raking operation, some amount of hydraulic fluid would end up in the river, leading to an environmental cleanup exercise. The current trash rake is undersized, leading to issues during raking operations. Often, the rake stalls out mid-operation due to the weight of accumulated debris it is trying to recover. The rake is also limited in its ability to lift logs and tress which can accumulate in front of the rakes, leading to potential personnel safety issues with operators being required to cut up the logs and trees while in very close proximity to the river's edge. Often times this is an operator leaning out over the handrail to address the problem. A safety action item was identified in 2016 related to the conveyor system that the trash rake utilizes to accumulate cleaned debris into a dumpster. This conveyor system, at the time posed a personnel safety threat due to its open operating nature. The risk of someone becoming entangled in the operating conveyor system drove a safety switch to be installed.

The recommended alternative is to replace the trash rake with an appropriately sized system that will allow full reach of the intake racks and accommodate large sized trees and logs to be removed from the river. This alternative would either replace the conveyor belt system with a new and safer alternative type of debris conveyance system or would remove that system entirely. This alternative is likely to be a packaged device with modern controls and electrical systems. The overall project cost of this alternative is estimated at \$1,500,000. Should this project be delayed, the operational safety and environmental issues would still be present, posing associated risks into the future.

VERSION HISTORY

Version	Author	Description	Date	Notes
1.0	<i>PJ Henscheid</i>	<i>Format existing BC into exec summary</i>	<i>7.2.20</i>	<i>5-year Capital Planning Process</i>
2.0	<i>PJ Henscheid</i>	<i>Completion of full BCJN document</i>	<i>8.4.20</i>	<i>5-year Capital Planning Process</i>

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GENERAL INFORMATION

Requested Spend Amount	\$1,500,000
Requested Spend Time Period	2 years
Requesting Organization/Department	J07/GPSS
Business Case Owner Sponsor	PJ Henscheid Andy Vickers
Sponsor Organization/Department	A07/GPSS
Phase	Initiation
Category	Project
Driver	Asset Condition

1. BUSINESS PROBLEM

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

The major driver for this business case is asset condition. The existing trash rake at Upper Falls is an articulating arm Atlas Polar device.

The trash rake has, since its installation, presented an environmental risk due to the hydraulic system that utilizes to function. When in use, the hydraulic system is suspended over the Upper Fall unit intake and the Spokane River. Should a hydraulic line fail during raking operation, some amount of hydraulic fluid would end up in the river, leading to an environmental cleanup exercise. While the rake is in its parked position, the hydraulic system is in very close proximity to the river and poses a threat to leaking.

The current trash rake is undersized, leading to issues during raking operations. Often, the rake stalls out mid-operation due to the weight of accumulated debris it is trying to recover. The rake is also limited in its ability to lift logs and tress which can accumulate in front of the rakes, leading to potential personnel safety issues with operators being required to cut up the logs and trees while in very close proximity to the river's edge. Often times this is an operator leaning out over the handrail to address the problem.

A safety action item was identified in 2016 related to the conveyor system that the trash rake utilizes to accumulate cleaned debris into a dumpster. This conveyor system, at the time posed a personnel safety threat due to its open operating nature. The risk of someone becoming entangled in the operating conveyor system drove a safety switch to be installed.

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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**

The major driver for this business case is Asset Condition. Having an effective and reliable trash cleaning device is imperative for the continued efficient operation of our Hydro generating units. Replacing this trash rake will not only provide for the safety of our operations staff, but will encourage the reliable operation of Upper Falls HED which contributes to the successful implementation of our Spokane River license.

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

This work is needed to address the personnel safety issues related to the conveyor system of the existing trash rake as well as address the potential environmental risks present with the existing design. Both of these risks remain if this work is deferred or not performed.

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.

Continued effective operation of upper falls hed will signify successful implementation of this project, but more importantly addressing the personnel safety risks as well and the environmental risks present in the current design will determine project success.

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.

Knuckle Boom	Marginal	4.67
Trashrake	Marginal	4.00

The above table is from the Net Condition Index and Rating summary. This information was compiled during the maintenance assessment of all Hydro assets performed in 2018. As shown, the condition of both the knuckle boom and trash rake are currently marginal, and do take into account the safety and environmental risks.

The recommended alternative is to replace the trash rake with an appropriately sized system that will allow full reach of the intake racks and accommodate large sized trees and logs to be removed from the river. This alternative would either replace the conveyor belt system with a new and safer alternative type of debris conveyance system or would remove that system entirely. This alternative would likely still utilize hydraulics to function, however, a robust containment system would be required and

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modern control system can detect and shut off the system when a leak is identified, often resulting in very small amount of leakage reaching the waters surface. This alternative is likely to be a packaged device with modern controls and electrical systems.

This alternative would likely include some amount of concrete work to facilitate and support the installation of a new trash rake. This could also include some concrete demolition and removal and replacement of embedded components.

This alternative would allow for reliable and safe operation and cleaning of the intake racks at Upper Falls, and would take into full consideration all personnel safety issues highlighted to date, as well as identify and address other possible safety issues.

This alternative is anticipated to begin in 2023, with an engineering assessment design starting that year. Construction could start as soon as early fall 2024. The project is anticipated to be transferred to plant sometime in 2025.

Option	Capital Cost	Start	Complete
Repace Upper Falls Trash Rake	\$1,500,000	01/2023	12/2024
Alt 1: Do Nothing	\$0	NA	NA

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

Data compiled from the replacement of the trash rake at Nine Mile in 208 helped to inform this capital request. It is anticipated the new trash rake at Upper Falls could be very similar in nature, both in scope of supply and operationally, to what was installed at Nine Mile.

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.

Some O&M cost savings are anticipated to be realized as a result of this project in reducing the amount of repairs and maintenance need to be performed on the trash rake. Also, the intent of the new design would allow for a safe and effective one person cleaning operations instead of the current practice of two operations personnel.

2023 – Engineering design and procurement of some of the equipment is anticipated

2024 – Completion of procurement and construction is anticipated

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

Operations and Power Supply will be impacted by this business case during implementation. Upper Falls generating unit will be required to be off-line during the totality of construction. This will affect plant operations and power supply, and will require all river flows to pass through the Control Works spillgates. The duration of construction activities is unknown at this time.

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

Alternative 1 – Do Nothing

This alternative would not allow for improving the functionality of the trash rake nor remove any of the safety risks associated with the existing rake.

The major risk associated with this alternative is the unreliable operation and personnel safety and environmental risks associated with the existing design. This alternative would continue to affect the Operation and Maintenance budget as repairs continue to be an issue and the equipment continue to age. Downtime for the plant could likely increase if outages of the trash rack increase due to age.

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.

Design efforts would kick off in 2023, with vendor selection, site visits and design analysis. Design should be completed by mid to late 2023, and procurement of equipment would commence. The majority of the scope of supply is anticipated to be delivered in early 2024, with construction activities starting as early as June of 2024 – following spring run-off. Construction is anticipated to take most of the summer and fall of 2024, with an anticipated transfer to plant of the entire project of the end of 2024.

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

The delivery of this project is highly important in the sustainability and operations of our Spokane river facilities and operating them safely and responsibly. The project will focus of the people responsible the delivering with a strong emphasis on performance. This nature of the project demands a collaborative environment with the wide array of key stakeholder groups. This will address personnel safety issues, environmental concerns, and unit reliability all at the same time.

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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 prudence will be reviewed and re-evaluated throughout the project

The project budget and total cost will be regularly reviewed with the project steering committee, as well as, receive approvals as described below for any changes in scope and cost. Prudence is also measured by remaining in compliance the FERC License such that we can continue to operate Spokane River 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

- GPSS Engineering; Civil, Mechanical, Electrical and Controls
- Hydro Operations
- Environmental, Permitting, and Licensing
- Master Scheduler
- Asset Management
- Project Accounting, Finance, and Rates
- Supply Chain and Legal
- Corporate Communications
- Construction Inspection and Project Management

2.8.2 Identify any related Business Cases

This project has no other relevant business cases.

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3.1 Steering Committee or Advisory Group Information

The advisory group for this project will consist of members from the Generation Production and Substation Support department, Power Supply, and the Environmental department. Specific individuals of the steering committee will be selected at a later date by the GPSS leadership team. Advisors are provided with monthly project status reports but, are only convened in the event of a necessary decision point.

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

The project will be led by the core project team. Any changes to scope, schedule and budget will be submitted for approval to the steering committee

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

The project is anticipated to utilize the Project Change Log to track and manage all Project Change Requests (PCR) associated with the delivery of the construction project. The PCR describes the need for change, supplemental documentation, related project artifacts, change order proposals, and any other pertinent information. PCR's are then signed for approval by the project approval thresholds, and then processed against the project risk registry, and or contract amendment with the contractor.

The undersigned acknowledge they have reviewed the Upper Falls Trash Rake Replacement 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:



Date:

8/4/20

Print Name:

PJ Henscheid

Title:

Mgr, Civil and Mechanical Engr

Role:

Business Case Owner

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Signature:



Date:

8/4/2020

Print Name:

Andy Vickers

Title:

Director, GPSS

Role:

Business Case Sponsor

Signature:

Date:

Print Name:

Title:

Role:

Steering/Advisory Committee Review