2016 Hydro Asset Strategy

This asset strategy was prepared before BPA's proposal to reduce costs. Spending levels in this document do not tie to proposed reductions. The strategy will be revised upon conclusion of the CIR and the IPR.

February 2014

Executive Summary

The objective of this 2016 Hydro Asset Strategy is to invest in equipment refurbishments and replacements to manage risk within funding constraints established by BPA's Access to Capital Strategy.

Responding to requests made in 2012 Capital Investment Review customer meetings, the plan outlines a multi-year capital program detailing various stages of development. It targets investments primarily in unit reliability equipment at Main Stem Columbia and Headwater / Lower Snake plants.

The plan in this strategy is defined by BPA's Access to Capital Strategy.

- The 2012 IPR Approved Plan capital program level of about $235 million per year increases current risk levels by 50 percent through 2022, after which risk returns to current levels by 2027 and beyond. This plan represents a sub-optimal level of future investment for adequate business continuity and cost effective reliability.
- A $235 million program level is forecasted to be more costly in the long run than higher capital reinvestment scenarios. The need to manage capital borrowing in the near term may result in higher long term system cost by increasing the risk of unit outages and replacement power costs.
- A $235 million program level is about 75 percent of what is suggested by strategy planning analyses and cost benchmarking studies.
- The plan does not include costs for modernization of John W. Keys Pump Generating Plant or other uncommitted economic opportunity investments (e.g., additional units at Dworshak, Libby, or John Day).
- A program consistent with 2012 IPR Approved Plan levels through 2017, but which then ramps to $300 million per year (2014 dollars) by 2022, is projected to reduce current risk levels by 50 percent in 2023 and 75 percent by 2031 with a net present value of $728 million relative to the 2012 IPR Approved Plan.

Under the 2012 IPR Approved Plan, the 20-year levelized fully allocated cost of the hydro system is forecasted to be $9.50 per MWh (2012 dollars).

1. Asset Category Overview

Introduction

The Federal Columbia River Power System (FCRPS) is a partnership between the US Army Corps of Engineers (Corps), the US Bureau of Reclamation (Reclamation), and Bonneville Power Administration (Bonneville).

FCRPS power related assets are financed through Direct Funding agreements between Bonneville and the Corps, and Bonneville and Reclamation. Through Direct Funding, over $500 million is spent annually by the FCRPS on Capital and O&M programs.

The FCRPS has a mandate to provide low cost, reliable power and effective resource stewardship to the Pacific Northwest region. It delivers power worth $4.4 billion annually to the people of the Pacific Northwest in addition to providing protection, mitigation, and enhancement of fish and wildlife. The system also provides an avoided carbon dioxide emission benefit of $1.4 billion annually by displacing fossil-fired generation emitting in excess of 40 million tons of carbon dioxide per year.

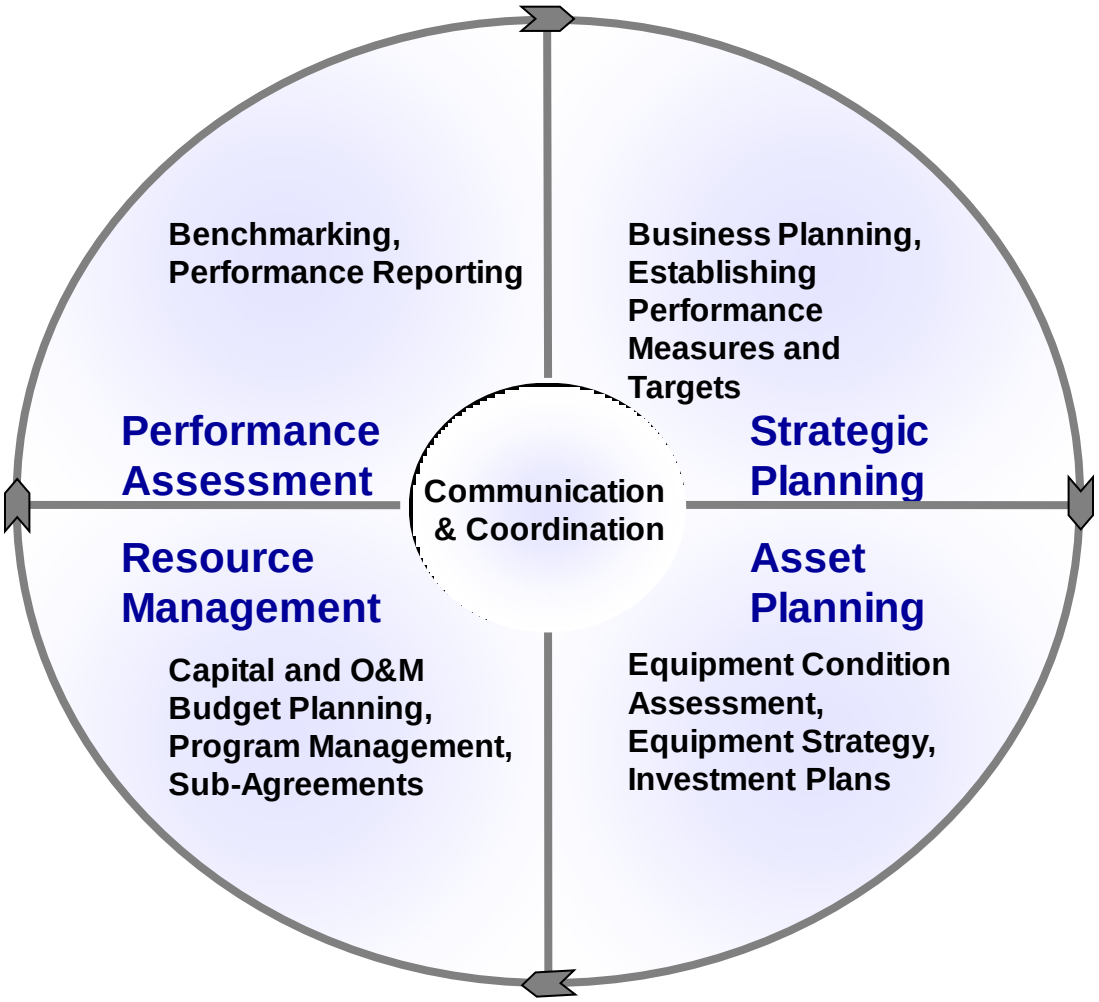
FCRPS Integrated Business Management Model

The FCRPS partnership uses an Integrated Business Management Model (IBMM) to provide a framework for ongoing asset-based planning and management. The IBMM consists of 12 business processes contained within four major areas - Strategic Planning, Asset Planning, Resource Management, and Performance Assessment.

A 3-Agency Steering Committee provides strategic direction to the hydropower program. Joint Operating Committee sub-committees provide direct oversight of specific aspects of the IBMM:

- Capital Investment Program
- O&M Program
- Performance Indicators
- River Management
- Hydro Optimization
- Technical Coordination
- Cultural Resources
- Fish and Wildlife

Direction from the three agencies of the FCRPS is to increase the level of efficiency, visibility and accountability for key business processes. The sub-committees are the primary management means for implementing this direction.



FCRPS Hydro System

The FCRPS is comprised of 31 hydroelectric plants – 21 operated by the Corps and 10 by Reclamation. The FCRPS has an overall capacity of 22,060 MW and, in an average water year, produces 76 million megawatt-hours of electricity.

Within the hydro asset category, the plants are grouped into four strategic classes depending on the role they play in the system. These categories are as follows:

- **Main Stem Columbia**: plants that provide the majority of power, ancillary services, and non-power benefits to the Pacific Northwest.
- **Headwater/Lower Snake**: plants that support services provided by Main Stem Columbia plants.
- **Area Support**: plants that do not support the region as a whole, but provide key power and non-power benefits to a sub-basin, primarily in the Willamette Valley.
- **Local Support**: plants that provide services locally, primarily in Southern Idaho.

FCRPS Hydro System

Plant	ID	Units	MW Capacity	aMW Energy	Strategic Class	Operator
Grand Coulee	GCL	24	6,735	2,497	Main Stem Columbia	Reclamation
Chief Joseph	CHJ	27	2,614	1,387	Main Stem Columbia	Corps
McNary	MCN	14	1,120	575	Main Stem Columbia	Corps
John Day	JDA	16	2,480	991	Main Stem Columbia	Corps
The Dalles	TDA	22	2,052	773	Main Stem Columbia	Corps
Bonneville	BON	18	1,195	513	Main Stem Columbia	Corps
Dworshak	DWR	3	465	214	Headwater/Lower Snake	Corps
Lower Granite	LWG	6	930	272	Headwater/Lower Snake	Corps
Little Goose	LGS	6	930	263	Headwater/Lower Snake	Corps
Lower Monumental	LMN	6	930	278	Headwater/Lower Snake	Corps
Ice Harbor	IHR	6	693	211	Headwater/Lower Snake	Corps
Libby	LIB	5	605	238	Headwater/Lower Snake	Corps
Hungry Horse	HGH	4	428	113	Headwater/Lower Snake	Reclamation
Albeni Falls	ALF	3	49	24	Area Support	Corps
Detroit	DET	2	115	46	Area Support	Corps
Big Cliff	BCL	1	21	13	Area Support	Corps
Green Peter	GPR	2	92	30	Area Support	Corps
Foster	FOS	2	23	12	Area Support	Corps
Lookout Point	LOP	3	138	37	Area Support	Corps
Dexter	DEX	1	17	10	Area Support	Corps
Cougar	CGR	2	28	17	Area Support	Corps
Hills Creek	HCR	2	34	18	Area Support	Corps
Lost Creek	LOS	2	56	36	Area Support	Corps
Palisades	PAL	4	177	74	Area Support	Reclamation
Minidoka	MIN	4	28	22	Local Support	Reclamation
Anderson Ranch	AND	2	40	18	Local Support	Reclamation
Boise Diversion	BDD	3	3	2	Local Support	Reclamation
Black Canyon	BCD	2	10	9	Local Support	Reclamation
Roza	ROZ	1	13	10	Local Support	Reclamation
Chandler	CDR	2	12	9	Local Support	Reclamation
Green Springs	GSP	1	17	6	Local Support	Reclamation
Total		**196**	**22,060**	**8,716**		

Products and Services

Power Generation and Delivery

- Electricity Production (MWh)
- Peak Electricity Capacity (MW)
- Spinning and Non-spinning Reserves
- Load Following
- Voltage Support
- System Restoration (e.g., Black Start)

Non-Power Purposes

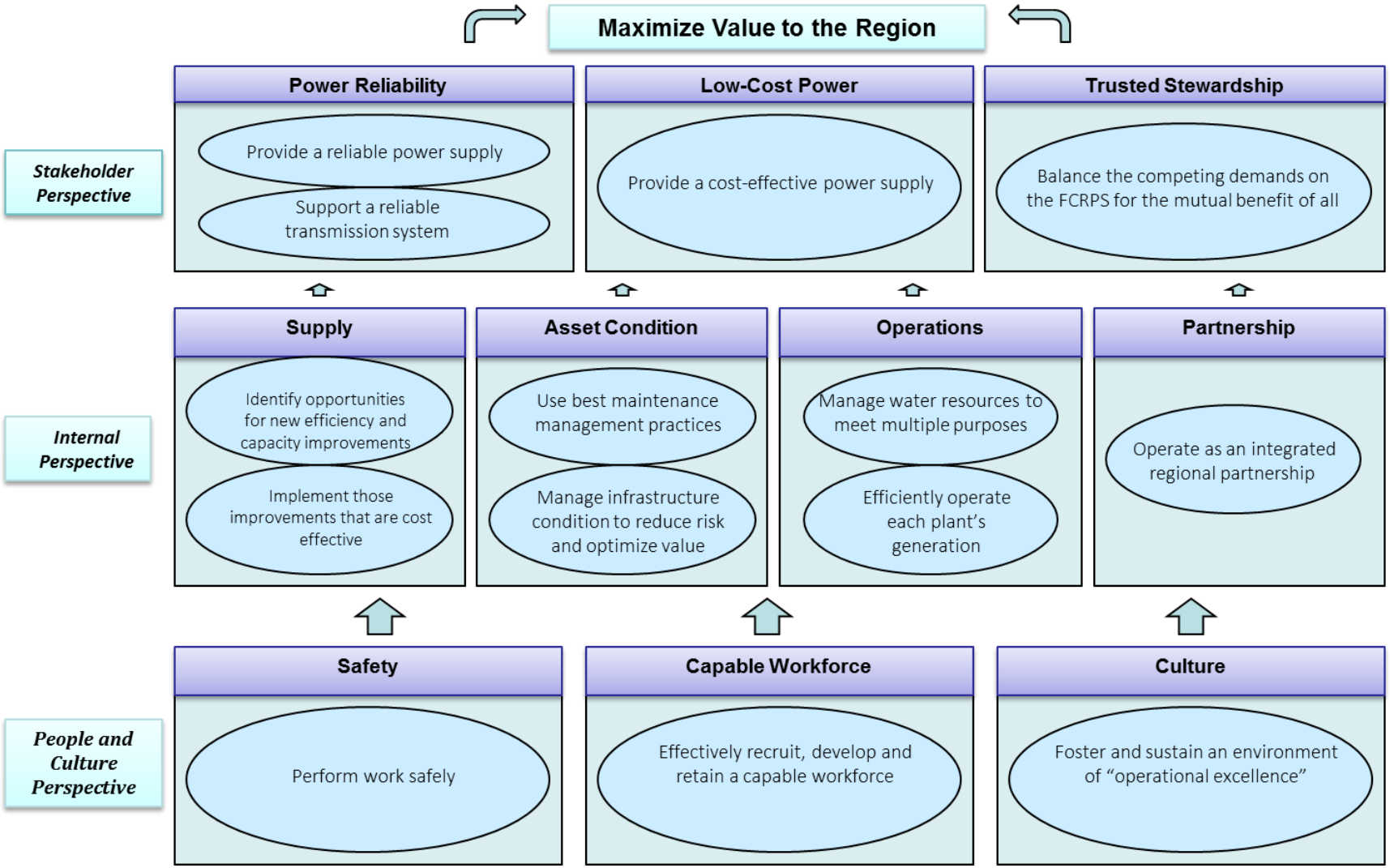
- Flood Damage Reduction – Use reservoir storage to shape natural water flows to reduce impacts to communities, farmland, and industry located along rivers.
- Navigation – Enable an inland waterway through a series of locks on the Columbia and Snake rivers.
- Irrigation – Increase the acreage of arable land in the Pacific Northwest through the storage and diversion of water.
- Recreation – Provide economic and social benefits by facilitating access to reservoirs and by making available parks and recreation areas.
- Municipal and Industrial Water Supply
- Water Quality
- Fish and Wildlife – Protect, mitigate and enhance fish and wildlife, including related spawning grounds and habitat, of the Columbia River and its tributaries.

Value of Strategic Classes by Purpose

Purpose	Main Stem Columbia	Headwater/Lower Snake	Area Support	Local Support
Power	Provides 76% of energy and capacity, and 30% of storage from the FCRPS. Provides nearly all the reserves and other ancillary services for supporting the 500 KV grid.	Provides 20% of energy and capacity, and 50% of storage from the FCRPS. Provides supplementary ancillary services for supporting the 500 KV grid.	Provides 3% of energy and capacity, and 18% of storage from the FCRPS. Provides voltage support to specific areas of the regional transmission grid	Provides 1% of energy and capacity, and 2% of storage from the FCRPS. Provides limited voltage support to local areas of the Pacific Northwest.
Flood Damage Reduction	Seasonal flood reduction and water management storage affecting significant parts of the Columbia River basin.	Seasonal flood reduction and water management storage affecting significant parts of the Columbia River basin.	Provides flood reduction benefits primarily in the Willamette Valley, but does not contribute significantly to the flood reduction capability of the overall Columbia River basin.	Provides flood reduction benefits in a local area
Navigation	Provides navigation for the lower Columbia River from below Cascade Locks to the Tri-Cities	Provides navigation for the lower Snake River from the Tri-Cities to Lewiston, ID	None	None
Irrigation	Primary source of irrigation for the Columbia River Basin	None	None	Primary source of irrigation within a specific region
Recreation	Significant recreation for boating and camping. Includes several “destination” recreation sites and numerous local sites.	Major recreation for boating and camping. Includes several “destination” and local sites.	Major recreation for boating and camping. Includes several “destination” and local sites.	Some boating and camping at local sites.
Fish and Wildlife	Significant regional role in management of reservoir lands, fish passage, and wildlife mitigation.	Significant role in management of reservoir lands, fish passage, flow augmentation and wildlife mitigation.	Provides a role in managing fish and wildlife primarily in the Oregon Cascades.	Localized role in fish and wildlife mitigation.

2. Asset Strategy Scope, Direction, and Objectives

FCRPS Hydro Strategy Map



FCRPS Hydro Strategy Logic and Scope

The FCRPS Hydro Strategy focuses on three goals:

- Low Cost Power;
- Power Reliability; and
- Trusted Stewardship

The strategy is implemented through a set of Direct Funding Agreements to:

- Ensure that life safety and environmental requirements are met;
- Mitigate the risk of power generation component failures by replacing or refurbishing equipment and purchasing spares when warranted;
- Increase the efficiency and/or capability of power facilities where economically feasible;
- Meet Bonneville's business continuity needs for a reliable supply of low-cost generation by ensuring power generating assets are properly operated, inspected, and maintained;
- Meet FCRPS commitments for fish and wildlife and cultural resource programs; and
- Fund a portion of high priority multi-purpose projects, in accordance with Bonneville's direct funding agreements with the Corps of Engineers and Bureau of Reclamation.

With this in mind, the 2016 strategy includes:

- Direct Funded Investment Program; and
- Direct Funded O&M Program.

FCRPS Hydro Strategy Logic and Scope

Program funding needs are established through the IBMM model, as described in section 1.

- In general, the **Capital Program** is comprised primarily of large, discrete investment needs for equipment replacement or refurbishment, largely driven by condition and risk.
- In contrast, the **O&M Program** reflects core funding for maintenance, operations, and minor equipment replacements, and is largely driven by the staffing needs of each facility.

The Capital Program funding proposals presented within this strategy focus on the 10-year period, FY2014 – FY2023. Investments target electrical and mechanical systems, less on civil features for dam safety, which are typically funded through appropriations, a share of which is reimbursed by Bonneville.

- Reinvestment costs for dam safety has been relatively low for the history of the FCRPS. Civil features are long-lived and rebuilding and/or replacement needs are negligible for the first 50 or more years of plant life. However, at some point significant reinvestment in civil works for dam safety is needed to extend useful asset life.
- For the focus period of this strategy, the exclusion of costs for dam safety civil features is not expected to materially affect the funding need forecast. However, as the hydro system continues to age, anticipating funding needs for dam safety will require more explicit attention in future strategies.

Forecasted Plan Results

FCRPS Hydro System Availability

In 2012, executive leads of the three FCRPS agencies entered into a series of discussions focusing on measures they believed were strategically important for the hydro program. In their most recent meeting on January 14, 2013, after discussing several measures including those developed for the 2014 hydro strategy, the executives narrowed the hydro program's strategic priority to one measure, choosing not to set formal targets for it: Hydro system availability performance compared to a 5-year system availability forecast. The executives directed the hydro program management team to focus its efforts on achieving the forecasted availability level.

The forecast increases 3.4 percent over the 4-year horizon, in part an artifact of capital and non-routine expense programs that are not fully defined in later years. The next availability forecast will improve that definition, with a trend that is likely flatter.

	FY2014	FY2015	FY2016	FY2017
Forecast	77.4%	77.5%	79.0%	80.8%

Criticality of Assets

Relative Cost of Unavailability. The criticality of a hydro asset is based largely on the quantity of energy produced, particularly at peak periods, and the financial impact of a loss of generation. Assets in the Main Stem Columbia and Headwater/Lower Snake strategic classes provide more than 96 percent of energy and capacity for the system.

Five plants – Grand Coulee, McNary, Chief Joseph, John Day and Dworshak – are considered particularly critical to the power system based on the significant financial impact of a generating unit outage at these facilities.

The figure on the following page groups FCRPS hydro plants by their strategic class and relative cost of unavailability (RCU) to the power system. The relative cost of unavailability is the annual cost of replacing lost generation from the least-used generating unit, or first 20 percent of lost plant availability, whichever is larger. No costs are included for replacing lost capacity, ancillary services, or non-power benefits.

Major RCU is up to $10 million per year, and is based on Bonneville's long-term forward price forecast and average water conditions. Extreme RCU ranges from $10 to $40 million annually, while Severe RCU exceeds $40 million per year. No value is included for avoided CO2 emissions.

The figure shows that Grand Coulee, McNary, Chief Joseph, John Day and Dworshak are the plants with the highest RCU.

Criticality of Assets

FCRPS Hydro Plant Classification

Relative Cost of Unavailability (RCU)	Local Support	Area Support	Headwater/ Lower Snake	Main Stem Columbia
Severe >$40m/yr				CHJ GCL MCN
Extreme $10 - $40m/yr			DWR	JDA
Major <$10m/yr	AND, BCD BDD, MIN, ROZ, CDR, GSP	BCL, DEX, LOS, DET, GPR, LOP, HCR, CGR, FOS, ALF, PAL	LIB, HGH, IHR, LGS, LWG, LMN	BON TDA

Strengths of the FCRPS Hydro System

Low, Stable Costs: The FCRPS hydro system provides a low and relatively stable cost of power, with a fully allocated system cost of less than $10 per megawatt-hour. Average annual generation is 76 million megawatt-hours. Costs are increasing over time for growth in the O&M Program and investments to repair and replace aging equipment.

Storage and Peaking: The FCRPS hydro system has a maximum useable storage of 10.5 ksfd, providing flood damage reduction, irrigation, fish and wildlife benefits, recreation opportunities, and increased value from the power system by storing water to be used when it is more valuable for generation.

Ancillary Services and Resource Integration: The hydro system provides all voltage support, load following, spinning and non-spinning reserves, and other ancillary services for Bonneville's transmission system. Hydropower also serves as the primary mechanism for integrating wind resources into the power system.

Climatic Risk: FCRPS hydro generation produces zero carbon dioxide emissions, which now are recognized as a primary contributor affecting climate change. Hydro generation both lessens climate change effects by reducing emissions that otherwise would be produced by alternative generation sources and remains cost effective within resulting weather variations that may influence water supply.

Energy Payback: Energy payback ratio is a comparison of the energy produced by a system divided by the energy consumed to build and operate the system over its useful life. Hydropower, with an energy payback ratio of 205, has the highest ratio of all generation sources. By comparison, the ratio for wind is 23 (without backup), nuclear fission (16), coal (11), and natural gas (4).

Skilled Workforce: The FCRPS has a dedicated and skilled workforce with a keen understanding of the operations and maintenance needs of the hydro system.

Weaknesses of the FCRPS Hydro System

Weather and Water Supply: Changing weather conditions and the resulting changes in water supply create a degree of uncertainty in hydropower production different than that from thermal generation alternatives. Between years, the difference in energy production from FCRPS hydro can be several thousand average megawatts. This presents unique challenges to managing the entire portfolio of power supply needed to meet the demands of Bonneville customers.

Environmental Costs: The FCRPS faces high environmental costs for mitigating the impact of developing the Columbia River Basin. The direct funded program costs considered in this strategy include $34 million per year for maintaining fish passage equipment and hatcheries. In addition to costs included in this strategy, environmental costs total more than $350 million per year for Bonneville's direct fish and wildlife program and the Corps' appropriated program to construct additional fish rearing and passage facilities. Indirect costs for changes in system operations now total several hundred million dollars per year.

Aging Workforce: The power industry as a whole is now facing a retirement eligibility bubble that poses significant risk to maintaining the workforce needed to operate and maintain facilities effectively. A large percentage of personnel working on-site at FCRPS hydro plants are eligible for retirement within five years.

Aging Infrastructure: The hydro system is also an aging infrastructure, approaching an average age of 50 years. The oldest plant in the system is Minidoka, with an in-service date of 1911. Bonneville Dam is the oldest Main Stem Columbia plant, with an in-service date of 1938. While many more years of valuable production can be expected from the hydro system, it faces significant challenges associated with maintenance and replacements demands to preserve this value.

Politically Unpopular: In Canada, Europe, Australia and New Zealand, hydropower is generally seen as a clean and reliable source of renewable energy. However, in the United States, and particularly in the Northwest, hydropower is often perceived more negatively despite the trends to look at hydropower as a renewable resource, which introduces added uncertainty into the future cost and supply of FCRPS hydro generation.

3. Current Performance, Condition, and Risk

Performance, Low Cost Power

Program Functions

The Capital Program includes:

- Reliability driven replacements of capital components;
- Economic opportunity investments to existing assets that are undertaken to improve system performance (e.g., turbine runner replacements to improve efficiency); and,
- Investments in new assets at existing facilities (e.g., adding a new generating unit), also based on economic opportunity.

The O&M Program is comprised of two cost categories,

- Routine Expense: reflects core funding for maintenance, operations, and minor equipment replacements, and is largely driven by the staffing needs of each facility; and,
- Non-Routine Expense: large, infrequent maintenance activities that are categorized as expense following accounting standards.

Performance, Low Cost Power

Fully Allocated Cost

Name of Asset	Completed Plant	Net Utility Plant	CWIP	Accumulated Depreciation	FY 2012 Depreciation	FY 2012 O&M Expense	FY 2011 Interest	Outstanding Fed. Approp.	Net Generation (GWH)	Production Cost ($/MWh)	Fully Allocated Cost ($/MWh)
	"Cumulative Capital cost" /a	"Useable value of plant" /b	"included in Net Utility Plant but not in Completed Plant"	"included in Net Utility Plant but not in Completed Plant" /c	"FY 2012 Accumulated Depreciation less FY 2011 Accumulated Depreciation"	"Annual expense" /d	"Interest for this year" /e	"Sum of remaining principle" /f	"Average generation based on 50-year hydro regulation studies"	"FY 2012 O&M Expense divided by Net Generation"	"(FY 2012 O&M Expense + Interest - Depreciation) divided by Net Generation"
Corps Assets											
Albeni Falls	$52,388	$36,108	$7,430	(23,710)	619	$6,877	$208	$3,090	208	32.98	31.01
Bonneville	$1,120,615	$719,703	$20,791	(421,703)	(19,131)	$24,784	$38,298	$512,497	4,490	5.52	18.31
Chief Joseph	$673,329	$391,699	$36,479	(318,109)	(9,781)	$19,474	$16,242	$238,241	12,154	1.60	3.74
Cougar	$44,834	$38,693	$5,582	(11,724)	3,627	$1,408	$2,722	$54,851	146	9.62	3.43
Detroit-Big Cliff	$87,485	$56,993	$1,782	(32,274)	(3,026)	$4,379	$85	$1,592	519	8.44	14.44
Dworshak	$313,368	$190,592	$3,006	(125,782)	(5,079)	$13,460	$9,053	$127,588	1,873	7.19	14.73
Green Peter-Foster	$58,252	$33,374	$1,291	(26,169)	(836)	$4,058	$16	$312	368	11.03	13.34
Hill Creek	$24,177	$15,982	$5,248	(13,443)	(558)	$1,098	$543	$7,988	161	6.81	13.64
Ice Harbor	$179,451	$108,036	$18,182	(89,597)	(3,438)	$8,799	$2,273	$35,777	1,845	4.77	7.87
John Day	$546,300	$308,779	$7,582	(245,103)	(7,755)	$20,730	$2,076	$32,967	8,685	2.39	3.52
Libby	$447,374	$273,675	$451	(174,149)	(5,428)	$8,744	$16,745	$235,714	2,086	4.19	14.82
Little Goose	$225,938	$123,026	$9,082	(111,995)	(3,267)	$8,507	$4,408	$63,790	2,304	3.69	7.02
Lookout Point-Dexter	$87,550	$64,981	$21,729	(44,298)	(1,161)	$5,878	$731	$13,249	410	14.34	18.95
Lost Creek	$30,513	$17,049	$701	(14,166)	(1,518)	$2,101	$1,005	$14,089	317	6.62	14.58
Lower Granite	$384,570	$239,739	$7,344	(152,175)	(3,917)	$14,421	$12,441	$177,499	2,386	6.04	12.90
Lower Monumental	$264,816	$146,220	$5,923	(124,519)	(3,863)	$8,496	$3,604	$53,015	2,435	3.49	6.55
McNary	$426,420	$234,382	$18,611	(210,649)	(4,769)	$18,761	$711	$13,665	5,033	3.73	4.82
The Dalles	$448,386	$245,834	$21,428	(223,980)	(6,950)	$16,964	$4,169	$70,416	6,771	2.51	4.15
USFW Lower Snake F&W	$0	$0	$0	-	-	$0	$0	$0			
Columbia River Fish Mitigation	$653,518	$670,453	$192,110	(175,174)	(12,278)	$362	$44,774	$1,018,844			
Other (COE LSCRP)	$4,181	$10,214	$4,457	1,576	(580)	$0	$16,521	$232,537			
NW Division Coordination						$1,227					
Adjustments											
Total Corps Assets	**$6,073,466**	**$3,925,530**	**$389,207**	**($2,537,143)**	**($89,089)**	**$190,529**	**$176,625**	**$2,907,721**	**52,189**	**3.65 $/MWh**	**8.74 $/MWh**
Reclamation Assets											
Boise Diversion-Anderson Ranch-Black Canyon	$30,170	$24,609	$4,673	(10,234)	(414)	$4,157	$295	$4,425	253	16.42	19.22
Chandler-Roza	$13,377	$10,856	$1,434	(3,954)	(186)	$1,890	$44	$862	161	11.73	13.15
Grand Coulee	$1,488,594	$1,087,573	$93,488	(494,509)	(22,103)	$67,247	$38,057	$550,642	21,872	3.07	5.83
Hungry Horse	$135,766	$83,257	$3,764	(56,272)	(1,800)	$4,188	$832	$13,268	986	4.25	6.91
Minidoka-Palisades	$113,998	$96,925	$16,255	(33,328)	(1,371)	$7,500	$6,343	$50,953	841	8.92	18.09
Green Springs	$10,889	$5,965	$3,548	(8,472)	(4)	$893	$655	$11,145	51	17.57	30.53
Adjustments						$0					
Total Reclamation Assets	**$1,792,795**	**$1,309,185**	**$123,161**	**($606,771)**	**($25,876)**	**$85,875**	**$46,226**	**$631,295**	**24,164**	**3.55 $/MWh**	**6.54 $/MWh**
Total Power Assets	**$7,866,261**	**$5,234,715**	**$512,368**	**($3,143,914)**	**($114,965)**	**$276,405**	**$222,851**	**$3,539,016**	**76,354**	**3.62 $/MWh**	**8.04 $/MWh**

/a -- Sum of the initial capital and replacement costs; capital cost of retired equipment is deducted. [FY10 Interim (Year-end) ASPRJ SUMMARY Report_Excel Version.xls]
/b -- Construction Work in Progress [FY11 Interim (Year-end) ASPRJ SUMMARY Report_Excel Version.xls]
/c -- Accumulated Depreciation [FY11 Interim (Year-end) ASPRJ SUMMARY Report_Excel Version.xls]
/d -- Annual expense cost by dam. [FY11 Interim (Year-end) ASPRJ SUMMARY Report_Excel Version.xls]
/e -- For the life of a debt, BPA pays interest annually, the principle is paid as a lump sum at the end of its payment period.
BPA refinanced its debt in FY1998, resulting in slightly higher interest rates. [Approriated Interest FY10.xls: line 128]
/f -- Remaining unpaid principle [Appropriated Interest FY10.xls: line 66]

Performance, Low Cost Power

Cost Benchmarks

The FCRPS benchmarks its hydro program annually in order to identify areas of best practice and the potential for performance improvement.

Costs benchmarked include Corps and Reclamation costs for hydropower, recreation, and joint-use purposes, and Bonneville costs for program coordination, planning, scheduling, generation dispatch, and fish and wildlife mitigation.

Because Direct Funding program costs are only a subset of all costs benchmarked, one-to-one comparisons cannot be made between the Direct Funding program and the benchmarks.

But the benchmarking results do provide useful information on the allocation of costs within the program and how FCRPS costs compare with those of its peers.

Performance, Low Cost Power

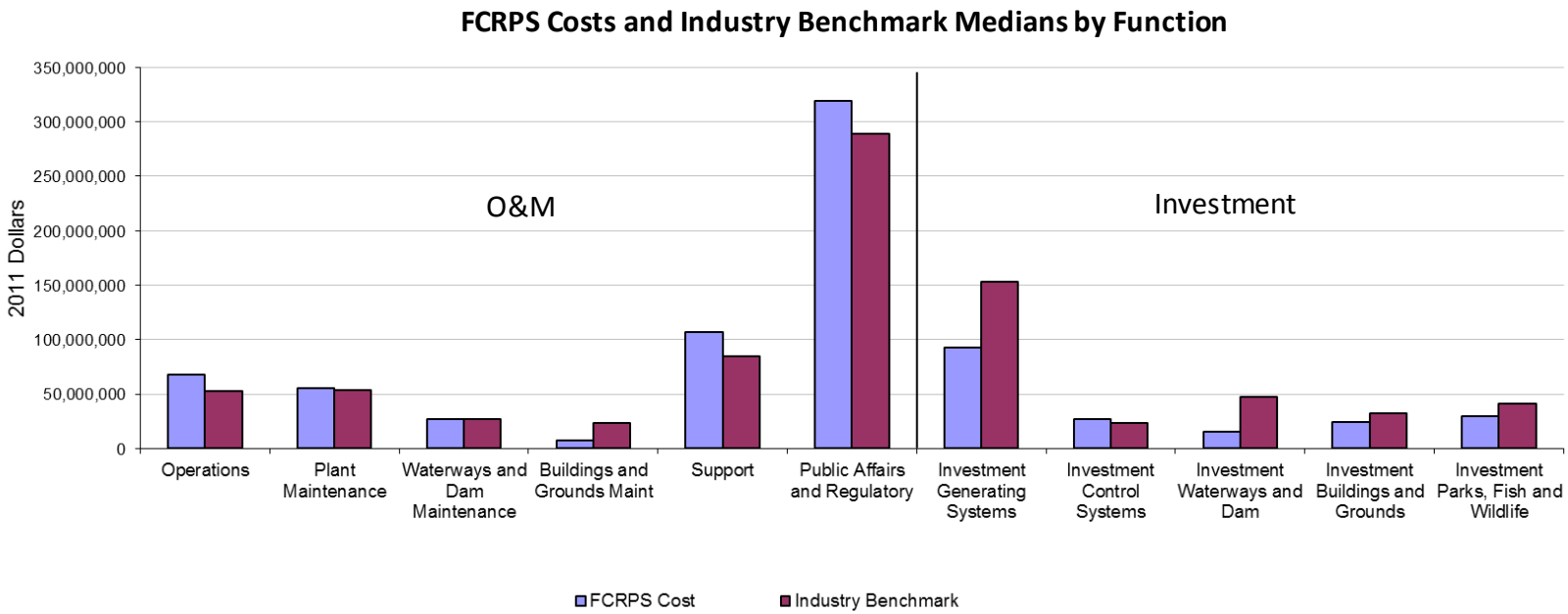
Cost Benchmarks

Most O&M Program function costs are above the benchmark median.

- Over half of O&M costs are in Public Affairs and Regulatory, most of which is BPA's fish program
- FCRPS total O&M Program cost of $583 million is 110 percent of the industry median

With the exception of Control Systems, all Investment function costs are below the median.

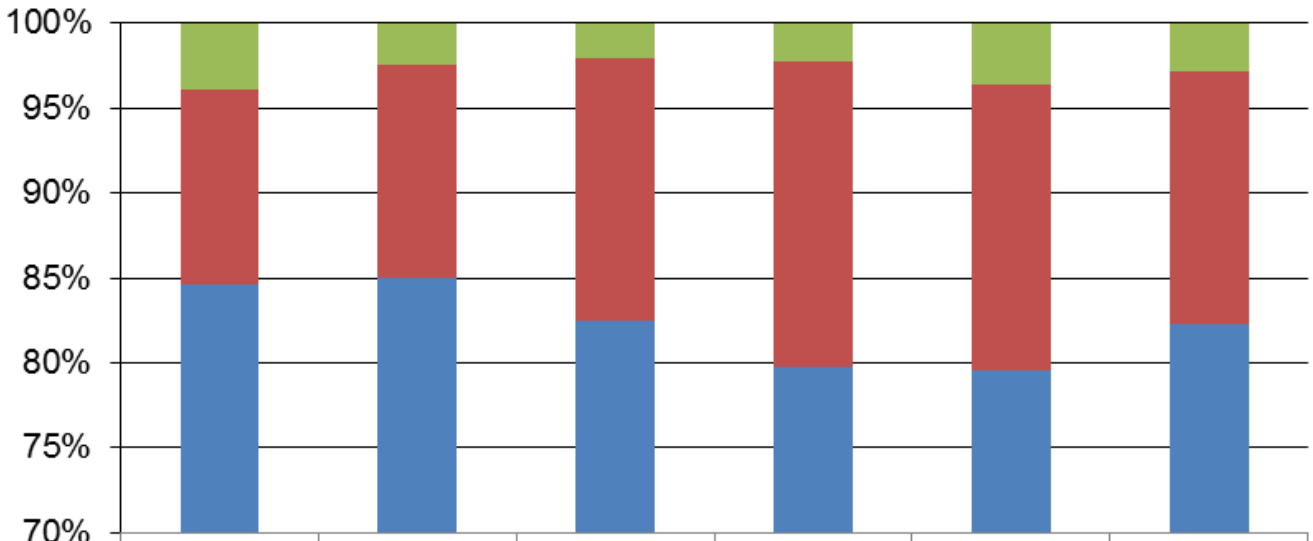
- The investment function looks at the average annual cost over a five year window
- Nearly half of FCRPS Investment costs are in Generating Systems
- FCRPS total Investment averaging $189 million per year is 64 percent of the industry median



Current Performance, Power Reliability

Availability

FCRPS hydro availability statistics have declined in recent years, primarily driven by outages at Grand Coulee. The 5-year availability factor averages 82 percent, ranging from 80 percent in 2012 to 85 percent in 2009.

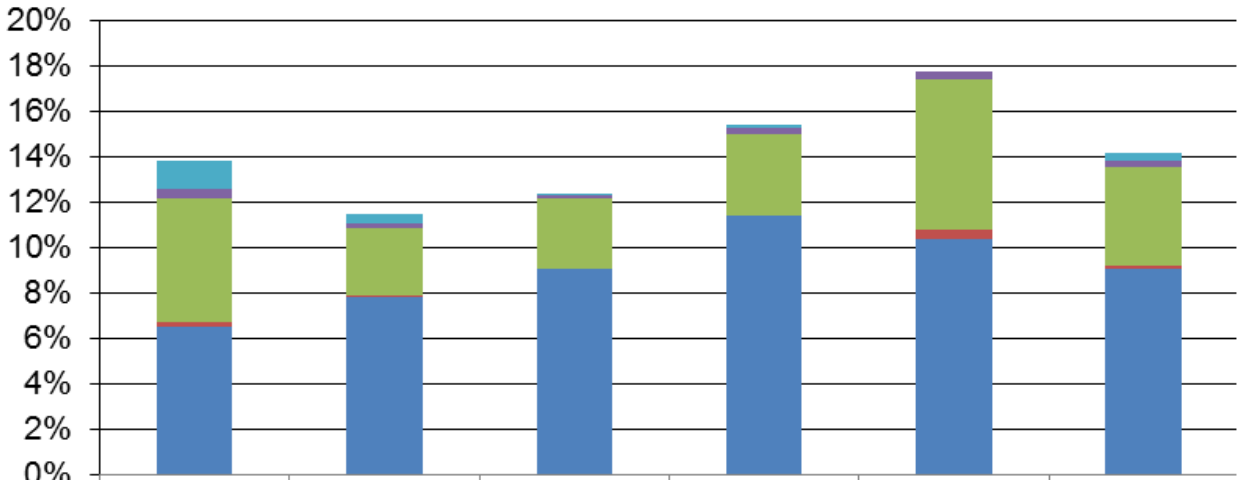


	2008	2009	2010	2011	2012	5-yr Avg
Forced Outages	3.9%	2.5%	2.1%	2.3%	3.6%	2.9%
Scheduled Outages	11.5%	12.5%	15.4%	17.9%	16.8%	14.8%
Availability	84.6%	85.0%	82.5%	79.8%	79.6%	82.3%

Current Performance, Power Reliability

Scheduled Outage Factor

The 5-year scheduled outage factor averages 14.8 percent, slightly higher than the industry average of 12.1 percent, largely driven by outages for routine maintenance, but also for capital projects.

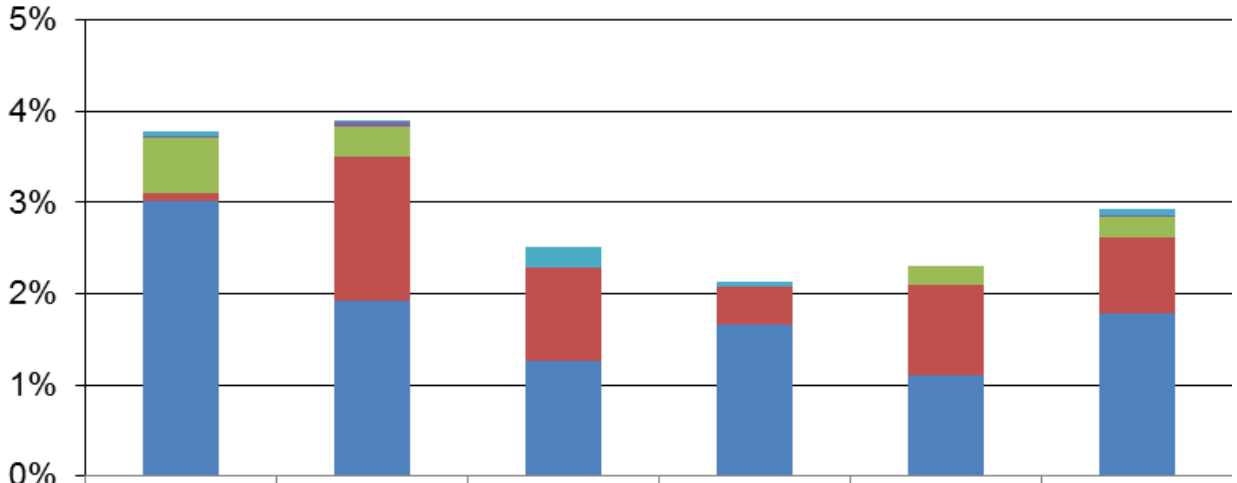


	2007	2008	2009	2010	2011	5-yr Avg
Fish	1.2%	0.4%	0.1%	0.1%	0.0%	0.4%
Transmission	0.4%	0.2%	0.1%	0.3%	0.4%	0.3%
Capital	5.5%	3.0%	3.1%	3.6%	6.6%	4.4%
Non-routine Maint.	0.2%	0.1%	0.0%	0.0%	0.4%	0.1%
Routine Maint.	6.5%	7.8%	9.1%	11.4%	10.4%	9.0%

Current Performance, Power Reliability

Forced Outage Factor

The 5-year forced outage factor averages 2.9 percent, also above the industry average of 2.3 percent. The 2010 rate was 2.1 percent, the lowest rate in several years, but it is again increasing as equipment ages.



	2007	2008	2009	2010	2011	5-yr Avg
Fish	0.1%	0.0%	0.2%	0.1%	0.0%	0.1%
Transmission	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
Capital	0.6%	0.3%	0.0%	0.0%	0.2%	0.2%
Non-routine Maint.	0.1%	1.6%	1.0%	0.4%	1.0%	0.8%
Routine Maint.	3.0%	1.9%	1.3%	1.7%	1.1%	1.8%

Current Performance, Trusted Stewardship

Avoided CO2 Emissions: In 2012, the FCRPS produced 86 million MWh of clean hydro generation, displacing energy that would have been generated by a fossil-fired resource alternative. Equivalent energy generated by a natural gas combustion turbine with a 9,000 BTU/kWh heat rate would have produced 45 million tons of CO2.

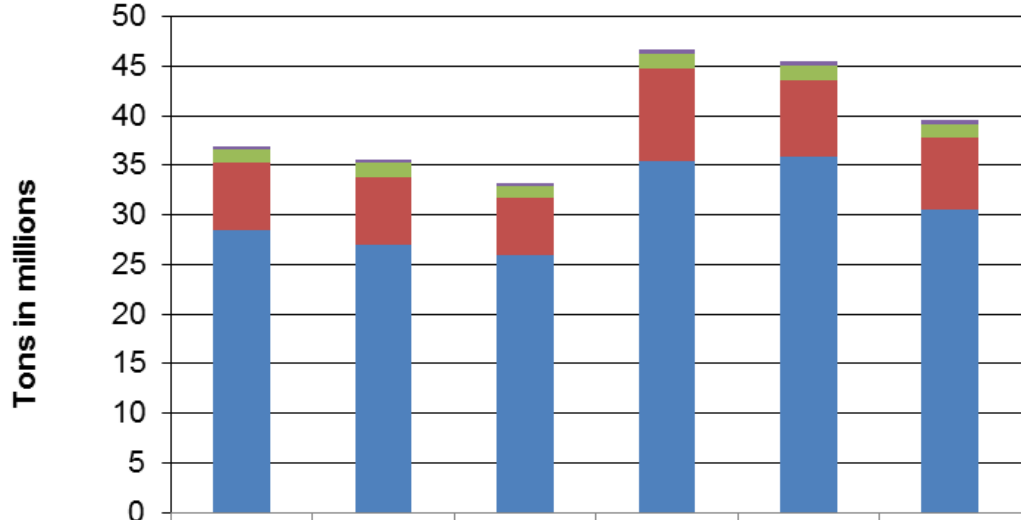
- FCRPS hydro delivers positive climate change benefits by reducing the amount of emissions for electricity that would be generated by other sources were the hydro system not available.
- The U.S. economy produces six billion tons of CO2 emissions each year, one third of which is produced by the electric power sector. The majority of electricity derived CO2 is produced by coal-fired power plants, with considerably less produced by natural gas and petroleum generation.
- In an average water year, the FCRPS hydro system reduces the CO2 footprint of a natural gas-fired alternative by 39 million tons – about 0.7 percent of total U.S. emissions.
- Displacement of a coal-fired resource alternative would have an impact twice that of natural gas.

Safety: The number of lost time accidents per 200,000 person-hours averaged 1.0 over the past five years.

- The results show that management of the safety program remains effective even during this period of growth in the large capital and extraordinary maintenance expense programs.
- This work involves activities that are non-routine and higher risk, presenting increased challenges to the workforce safety environment. The safety program also faces additional challenges related to an aging workforce.

Current Performance, Trusted Stewardship

Avoided CO2 Emissions



	2008	2009	2010	2011	2012	5-yr Avg
Local Support	0	0	0	0	0	0
Area Support	1	1	1	1	1	1
Headwater/Lower Snake	7	7	6	9	8	7
Main Stem Columbia	28	27	26	35	36	31

Lost Time Accidents per 200,000 person-hours

Measure	2009	2010	2011	2012	2013	5-yr Avg.
Lost Time Accident Rate	1.2	0.5	1.1	1.4	0.9	1.0

Condition Overview

The FCRPS manages 196 main generating units in 31 hydro plants, plus 16 additional station service, fish, and pump turbine units. It considers thousands of equipment components in maintenance and investment planning.

Component condition is a key driver of maintenance and investment needs.

- Routine maintenance activities identify and address deficiencies prior to their posing threats to equipment reliability.
- Even with effective maintenance programs, condition will eventually deteriorate to the point where inadequate reliability will warrant reinvestment.
- There are few redundant or spare components in hydroelectric generating facilities and, as such, it is important that the condition of major components be understood and managed.

The FCRPS hydro program uses hydroAMP to assess the condition of power train and auxiliary hydro plant components.

- Condition ratings continue to decline due in part to a lower than necessary reinvestment levels in aging and unreliable equipment.

Condition Ratings

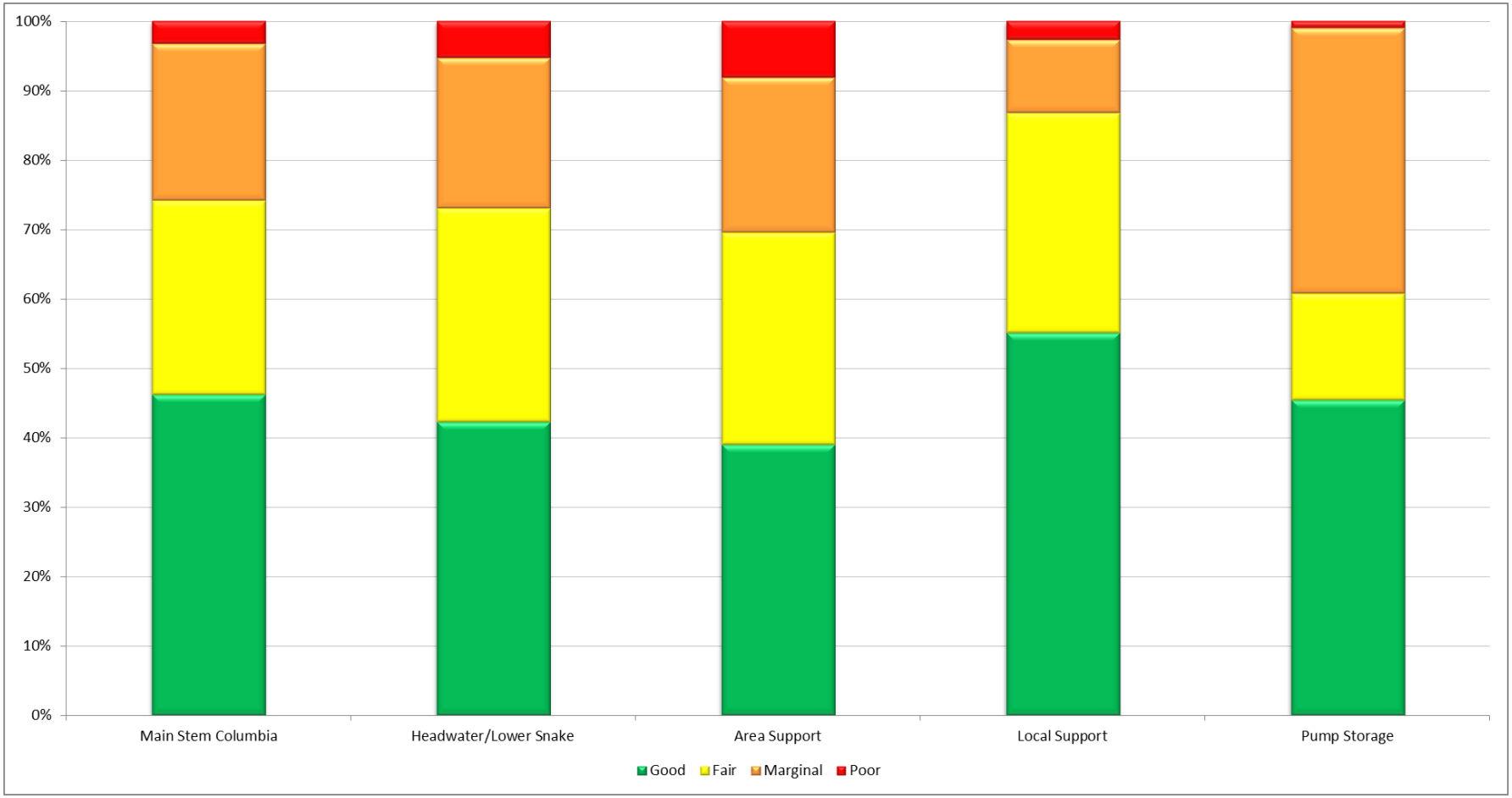
Condition ratings for each equipment type are based on a set of objective condition indicators related to operational performance, maintenance history, physical inspection, and age. Condition indicators are weighted and summed to derive a condition rating, ranging from 10 to 0. Numeric scores are further described qualitatively as follows:

- 8.0 – 10.0: Good
- 6.0 – 7.9: Fair
- 3.0 – 5.9: Marginal
- 0.0 – 2.9: Poor

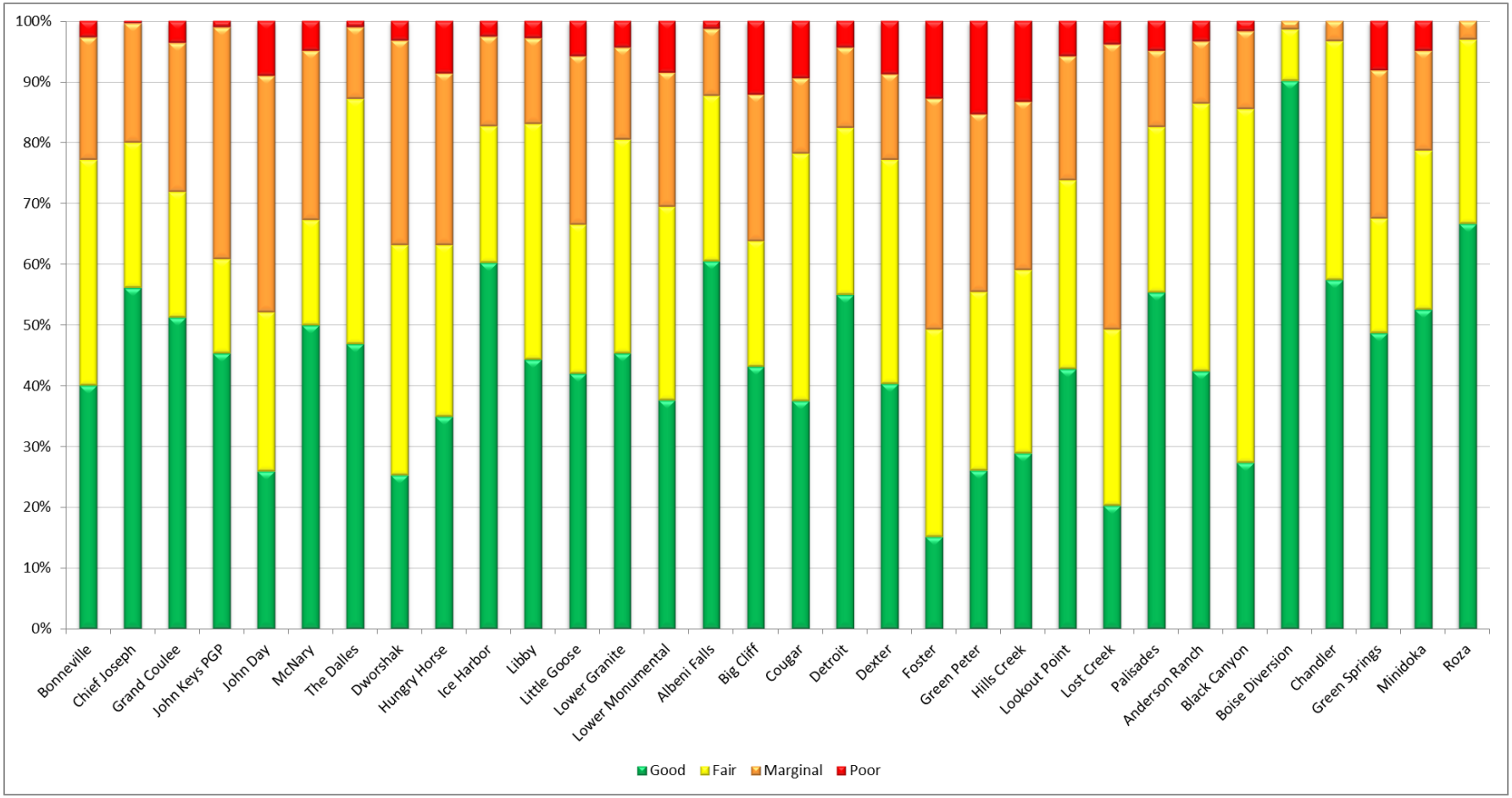
Condition by Strategic Class: About 75 percent of all equipment at Main Stem Columbia and Headwater/Lower Snake plants is currently in Good or Fair condition. Area Support plants have somewhat lower ratings and Local Support plants as a group have higher condition ratings. Pump storage (John Keys III Pump Generating Plant) has the lowest condition rating of all strategic classes.

Condition by Plant: Average condition rating by plant varies, with three critical plants – Grand Coulee, McNary and John Day – having below average ratings.

Current Condition by Strategic Class: All Equipment



Current Condition by Plant: All Equipment



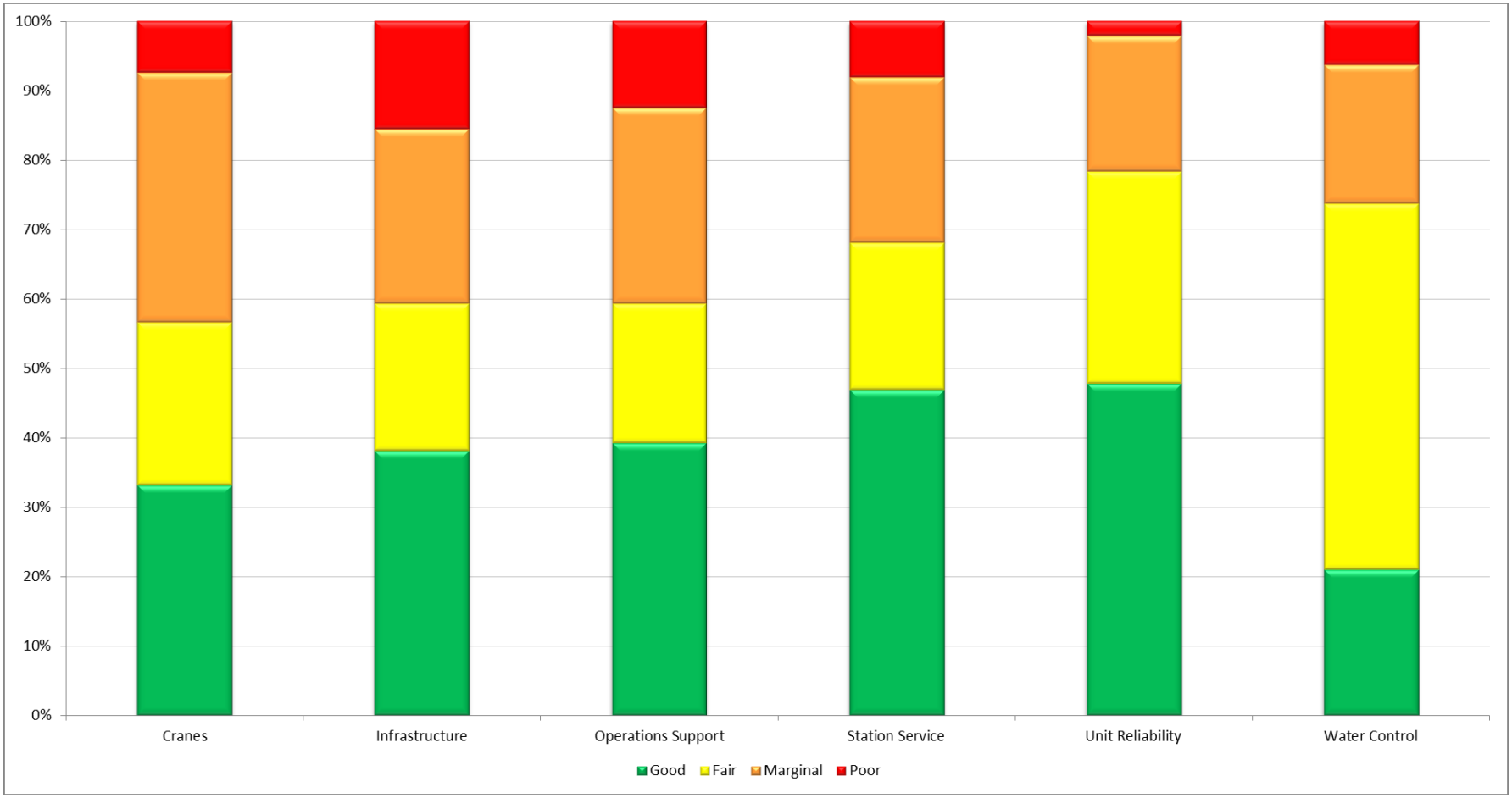
Component Condition

Condition by Equipment Category: Cranes have the lowest overall condition rating among equipment types, followed by infrastructure and operations support. Because cranes are needed to lift heavy equipment (including generation affecting equipment) and present considerable safety risk, satisfactory condition is a priority.

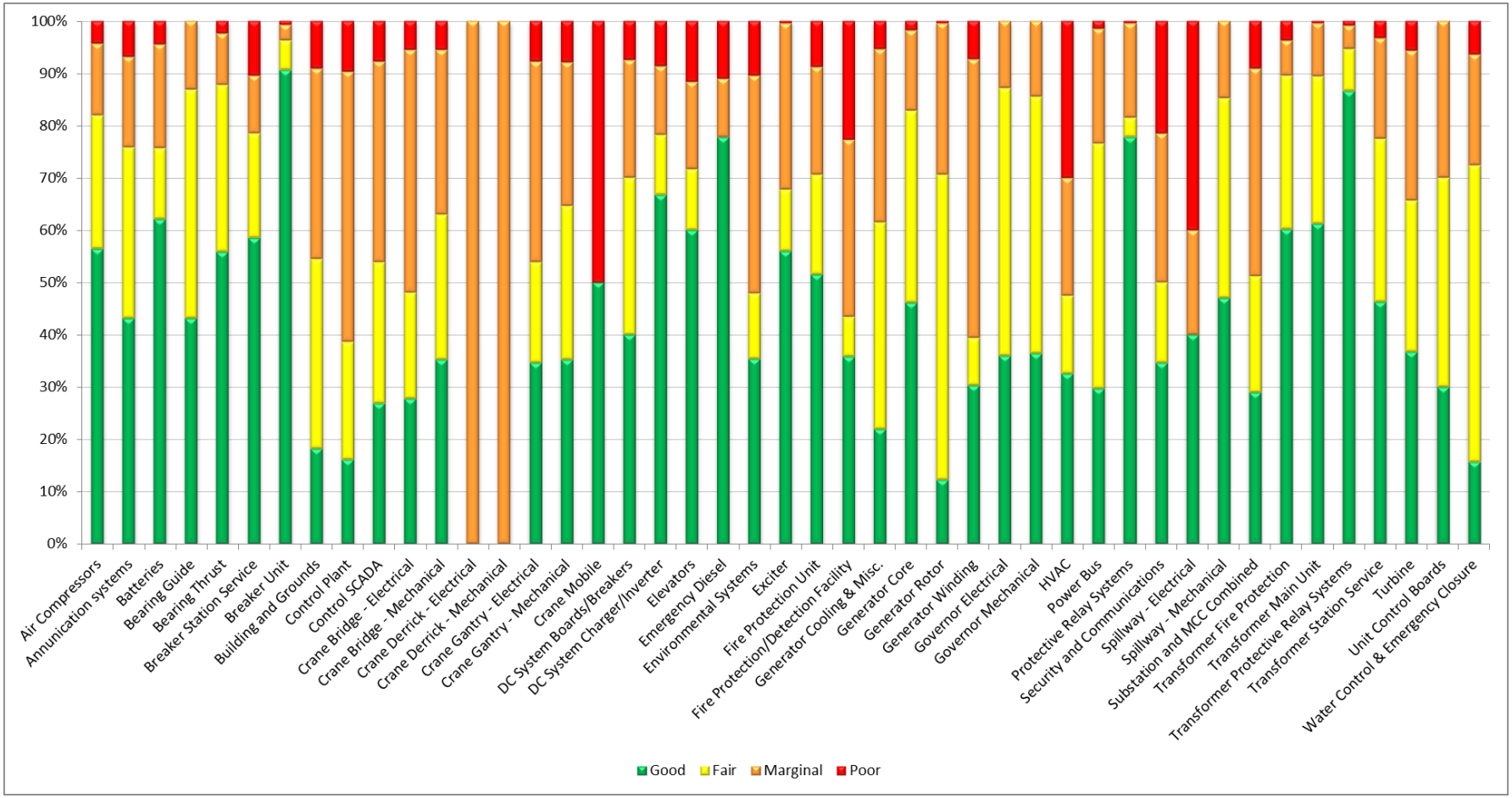
Station service, unit reliability and water passage systems have relatively higher condition ratings.

All Equipment: Condition varies by types but about two-thirds of all equipment is currently in Good or Fair condition.

Current Condition by Equipment Category

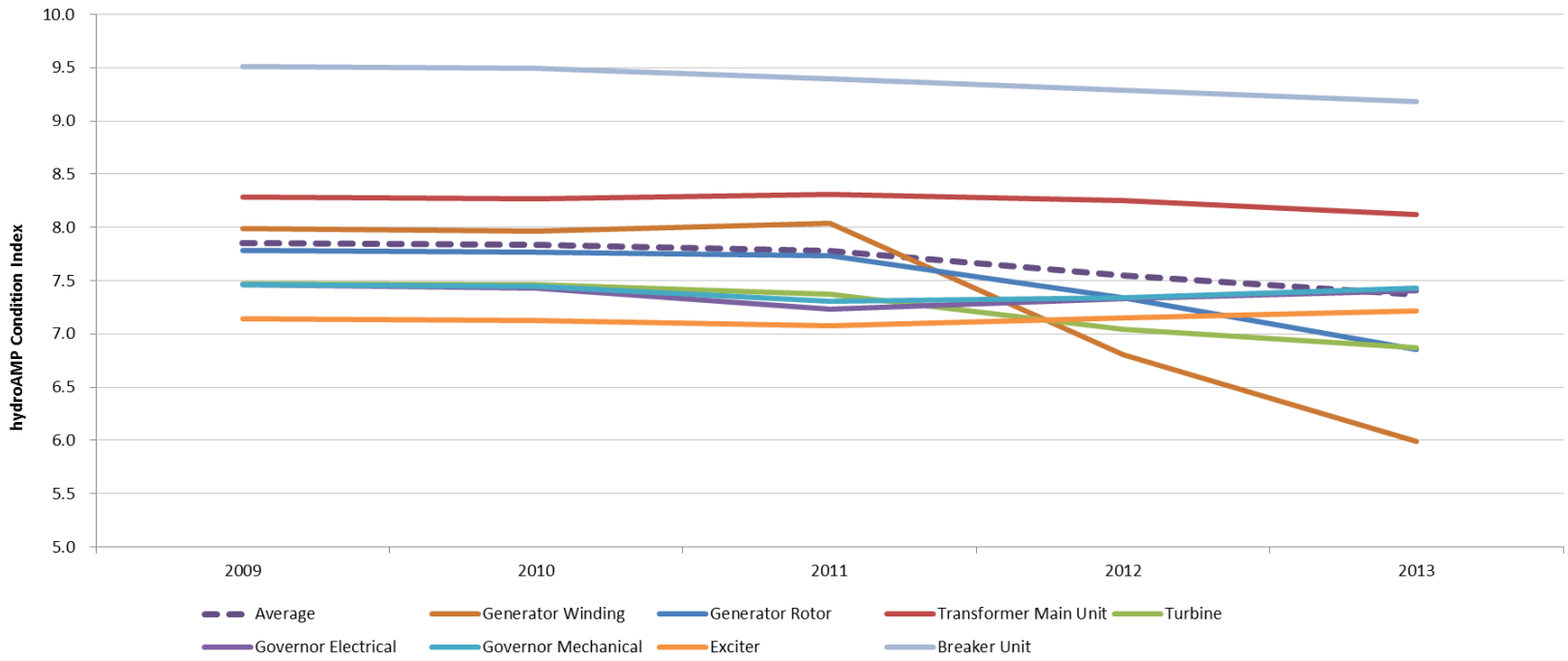


Current Condition: All Equipment



Trend of Condition Rating (2009 – 2013)

The average condition rating of major power train components has declined from 7.8 to 7.3 over the past five years. The components in the best overall condition are unit breakers which have recently undergone a system-wide replacement program. The condition of generator windings declined significantly since 2011, in part due to a change in the condition indicator weighting algorithm which placed more emphasis on age, but also due to other factors at several plants, including Grand Coulee. Turbine condition is also declining at a high rate at Lower Columbia and Snake River plants.



Age of Equipment

Background: Near term investment needs are driven primarily by component condition and risk.

However, understanding component age helps to establish if equipment is nearing the end of its useful life and may soon present a risk to asset performance.

Furthermore, when age is profiled for the entire equipment portfolio it can become a tool to identify if near-term investment strategies could result in future investment needs that create unacceptable financial pressures or resource constraints.

The FCRPS has created age profiles of its facilities using “percent of design life” as a primary measure. For example, a 30 year old component with a design life of 40 years is represented as being at 75 percent of design life.

This allows comparison across component types, recognizing that design life can vary considerably across component types or designs.

Age of Equipment

For presentation purposes, component ages have been grouped into four categories to create asset profiles. These categories are as follows:

- Less than 50 percent of design life;
- 50 to 100 percent of design life;
- 100 to 150 percent of design life, and
- Greater than 150 percent of design life.

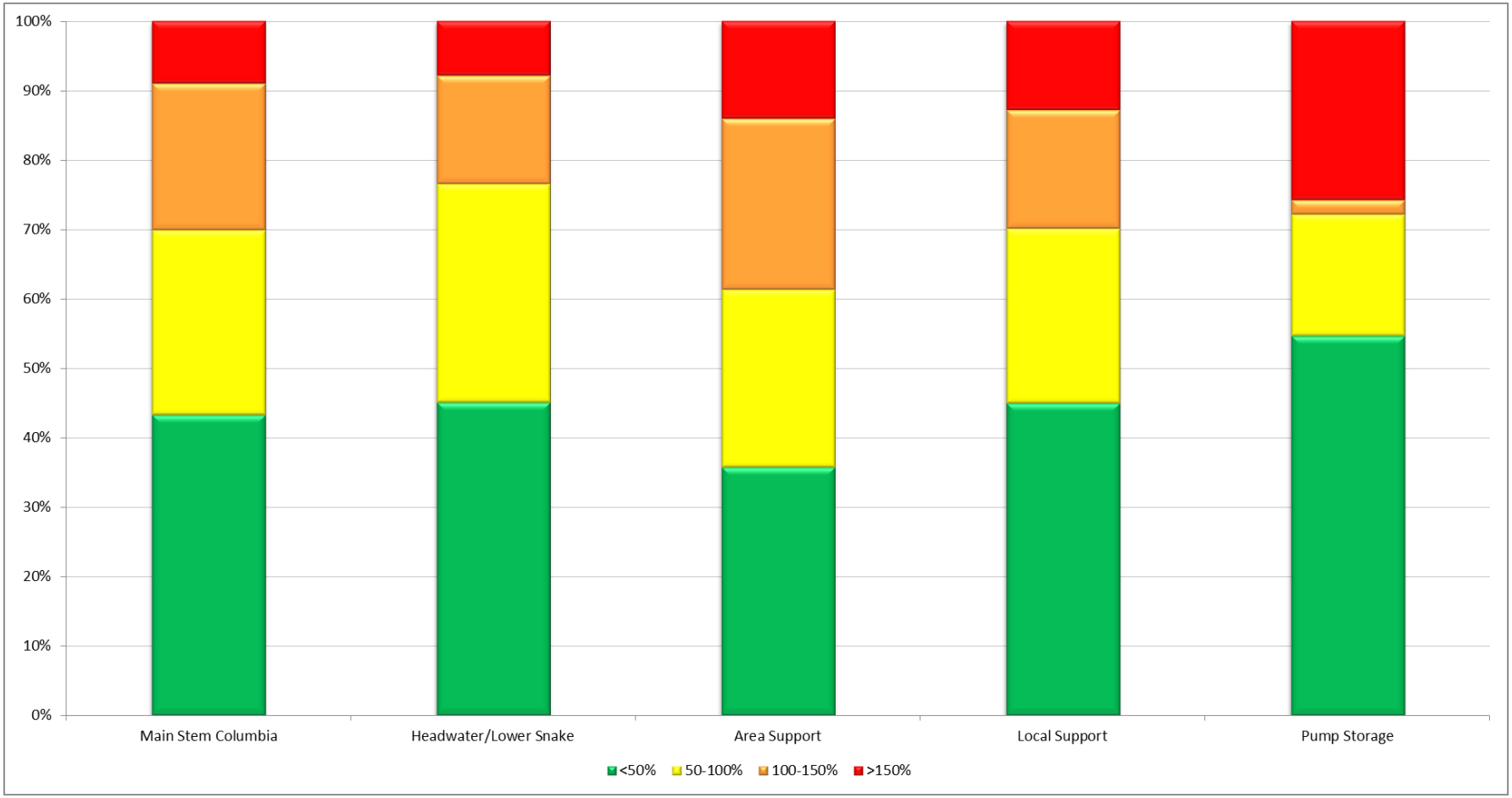
Current Age by Strategic Class:

- About 25 percent of equipment has exceeded its design life in the Main Stem, Headwater/Lower Snake and Local Support classes.
- For the Area Support class, nearly 40 percent of equipment has exceeded design life.

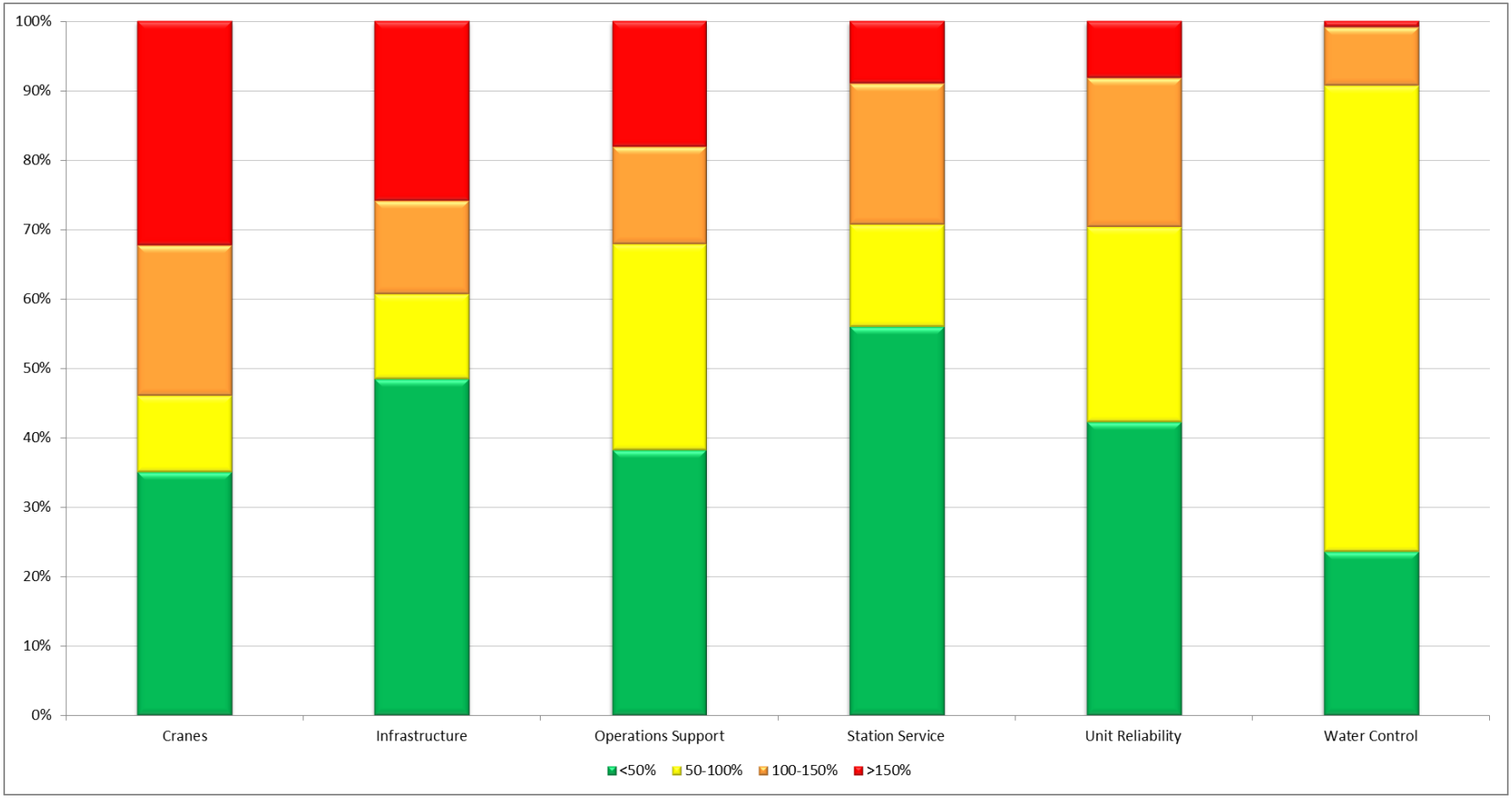
Current Age by Equipment Type:

- Nearly 50 percent of cranes and infrastructure equipment has exceeded design life. The condition of cranes has declined fairly significantly in the past two years. The combination of condition and age make cranes a likely candidate for re-investment.
- Water control equipment (spillway electrical/mechanical and emergency closure) has the fewest percentage of components exceeding design life.

Current Age by Strategic Class: All Equipment
(Percent of Design Life)



Current Age by Equipment Type
(Percent of Design Life)



Risk Assessment

FCRPS hydro asset management related risks are managed collaboratively by Bonneville's Federal Hydro Projects organization, the Bureau of Reclamation and Corps of Engineers. Asset management is the collective and collaborative efforts of these organizations.

Key requirements related to Bonneville's long-term outcomes are that the FCRPS:

- Meets equipment availability requirements (machine availability);
- Meets generation reliability standards, including compliance with WECC/NERC standards;
- Meets environmental requirements, particularly as related to management of water resources and equipment for fisheries purposes; and,
- Meets safety and security requirements.

Risk areas that could affect the long-term outcomes include the following:

- Failure of power train components;
- Failure of other generating station components not directly tied to the power system;
- Failure of Transmission assets;
- Effectiveness of security systems;
- Acts of nature; and
- Legal, regulatory and policy decisions that affect hydro operations or investment needs.

Failure of Hydro Plant Equipment

Loss of hydro plant equipment can lead to a number of negative consequences, including:

- Economic losses as a result of the need to replace components;
- Economic losses as a result of the need to purchase replacement power to meet contractual obligations, or lost opportunities to sell power to the market;
- Safety issues, should the catastrophic failure of a component cause injury or death;
- Environmental impacts such as the off-site release of oil;
- Regulatory violations through an inability to meet preferred unit operation, temperature controls, or Total Dissolved Gas (TDG) limits;
- Operational and Transmission support impacts such as unplanned spill or inability to provide reserves, voltage support, or capacity at peak periods, and
- Other stakeholder impacts such as lost pumping ability for Reclamation's irrigation customers.

The risk of equipment failure is assessed using two tools:

- Risk maps for safety, environmental and financial risk, and
- By quantifying lost generation risk.

Risk: Condition Index vs. Likelihood of Failure

The hydro program correlates a condition rating with the likelihood of equipment failing to perform as expected. An equipment component with a low condition rating has a higher likelihood of failure than one with a higher rating. The correlation is shown below.

Likelihood	Condition Index	Description
Almost Certain	0 to 0.9	Poor
	1 to 1.9	
	2 to 2.9	
	3 to 3.9	Marginal
	4 to 4.9	
	5 to 5.9	
	6 to 6.9	Fair
	7 to 7.9	
	8 to 8.9	Good
Rare	9 to 10	

Safety and Environmental Risk Maps

Risk is the product of likelihood and consequence. Two items with the same potential consequence will have different levels of risk if the likelihood of occurrence differs.

On the following maps, both safety and environmental risks are identified as being high, medium, or low.

- Safety consequences range from a low of “first aid required” to a high of “multiple fatalities”.
- Environmental consequences range from “no impact” to “detrimental or catastrophic off-site impact”.

Safety: High risk items have declined in this area since the 2014 strategy:

- 32 Water control items (vs. 63 in the 2014 Plan)
- 50 Operations support (vs. 53)
- 10 Unit Reliability (vs. 15)

Environmental: Similarly, there are currently only six items at high risk:

- 33 Water control (vs. 68)
- 53 Operations support (vs. 62)
- 6 Unit Reliability (vs. 7)

Current Safety Risk Map

Likelihood	No or minor injury, first aid	Treatment by medical professional	Lost time Accident - temporary disability	Lost Time Accident - permanent disability/fatality	Multiple fatalities
High	13 Infrastructure 4 Operations Support 22 Station Service 5 Unit Reliability 1 Water Control	2 Cranes 7 Infrastructure 11 Operations Support 17 Station Service 14 Unit Reliability	24 Operations Support	12 Operations Support	6 Unit Reliability 7 Water Control
Medium	8 Infrastructure 5 Operations Support 70 Station Service 148 Unit Reliability 2 Water Control	8 Cranes 2 Infrastructure 19 Operations Support 18 Station Service 57 Unit Reliability	8 Cranes 26 Operations Support 5 Station Service 1 Unit Reliability	14 Operations Support	4 Unit Reliability 25 Water Control
Low	14 Infrastructure 12 Operations Support 53 Station Service 416 Unit Reliability	42 Cranes 10 Infrastructure 33 Operations Support 8 Station Service 37 Unit Reliability 5 Water Control	31 Cranes 23 Operations Support 16 Station Service 25 Unit Reliability	6 Operations Support	15 Unit Reliability 19 Water Control
Very Low	13 Infrastructure 3 Operations Support 6 Station Service 199 Unit Reliability	10 Cranes 7 Station Service 18 Unit Reliability	9 Cranes 2 Station Service 21 Unit Reliability		17 Unit Reliability 42 Water Control
None	47 Infrastructure 70 Operations Support 226 Station Service 1939 Unit Reliability 2 Water Control	52 Cranes 41 Infrastructure 69 Operations Support 125 Station Service 391 Unit Reliability 29 Water Control	55 Cranes 56 Operations Support 70 Station Service 208 Unit Reliability	21 Operations Support	233 Unit Reliability 92 Water Control

Consequence

Condition: 0 → 10

Risk Level	Low	Medium	High

Current Environmental Risk Map

Likelihood	No impact	Impact to on-site environment (simple remediation)	Limited impact off-site (localized remediation required)	Detrimental impact on- or off-site (long-term remediation required)	Detrimental or catastrophic impact off-site (mitigation impossible)
High	2 Cranes 20 Infrastructure 4 Operations Support 22 Station Service 5 Unit Reliability	2 Operations Support 17 Station Service 14 Unit Reliability	40 Operations Support 6 Unit Reliability 1 Water Control	5 Operations Support	7 Water Control
Medium	8 Cranes 10 Infrastructure 5 Operations Support 70 Station Service 137 Unit Reliability	7 Operations Support 18 Station Service 68 Unit Reliability	8 Cranes 44 Operations Support 5 Station Service 5 Unit Reliability 2 Water Control	8 Operations Support	25 Water Control
Low	42 Cranes 24 Infrastructure 12 Operations Support 53 Station Service 351 Unit Reliability	7 Operations Support 8 Station Service 102 Unit Reliability	31 Cranes 43 Operations Support 16 Station Service 40 Unit Reliability 5 Water Control	12 Operations Support	19 Water Control
Very Low	10 Cranes 13 Infrastructure 3 Operations Support 6 Station Service 139 Unit Reliability	7 Station Service 78 Unit Reliability	9 Cranes 2 Station Service 38 Unit Reliability		42 Water Control
None	52 Cranes 88 Infrastructure 70 Operations Support 226 Station Service 1667 Unit Reliability	10 Operations Support 125 Station Service 663 Unit Reliability	55 Cranes 113 Operations Support 70 Station Service 441 Unit Reliability 31 Water Control	23 Operations Support	92 Water Control

Consequence

Condition: 0 → 10

Risk Level	Low	Medium	High

Current Financial Risk Map

The financial risk map is also segmented into high, medium, and low risk areas.

Financial consequences are a result of two factors in the event of a failure:

- The cost of replacement power for any lost generation, and
- Incremental direct costs for collateral damage, procurement, and scheduling/workforce inefficiencies.

There are currently 326 equipment items in the high risk area of the map:

- 193 Unit Reliability
- 78 Station Service
- 30 Operations Support
- 17 Water Control

Current Financial Risk Map

Likelihood	Insignificant < $ 10K	Minor $ 10K to $ 100K	Moderate $ 100K to $ 1 M	Major $ 1 M to $ 10 M	Extreme > $ 10 M
High	3 Operations Support 1 Station Service	2 Cranes 25 Operations Support 13 Station Service 2 Unit Reliability 3 Water Control	17 Infrastructure 21 Operations Support 10 Station Service 16 Unit Reliability 4 Water Control	3 Infrastructure 1 Operations Support 15 Station Service 7 Unit Reliability 1 Water Control	1 Operations Support
Medium	13 Operations Support 7 Station Service	14 Operations Support 10 Station Service 35 Unit Reliability 1 Water Control	8 Cranes 10 Infrastructure 30 Operations Support 23 Station Service 25 Unit Reliability 14 Water Control	7 Cranes 7 Operations Support 51 Station Service 134 Unit Reliability 10 Water Control	1 Cranes 2 Station Service 16 Unit Reliability 2 Water Control
Low	1 Infrastructure 19 Operations Support	1 Cranes 6 Infrastructure 20 Operations Support 6 Station Service 21 Unit Reliability 3 Water Control	42 Cranes 15 Infrastructure 31 Operations Support 24 Station Service 82 Unit Reliability 16 Water Control	26 Cranes 2 Infrastructure 4 Operations Support 47 Station Service 305 Unit Reliability 4 Water Control	4 Cranes 85 Unit Reliability 1 Water Control
Very Low	3 Operations Support	4 Infrastructure 4 Station Service 4 Water Control	5 Cranes 8 Infrastructure 3 Station Service 44 Unit Reliability 35 Water Control	14 Cranes 1 Infrastructure 4 Station Service 166 Unit Reliability 3 Water Control	4 Station Service 45 Unit Reliability
None	5 Infrastructure 97 Operations Support 6 Station Service	1 Cranes 16 Infrastructure 62 Operations Support 115 Station Service 351 Unit Reliability 11 Water Control	50 Cranes 62 Infrastructure 52 Operations Support 124 Station Service 781 Unit Reliability 89 Water Control	56 Cranes 5 Infrastructure 4 Operations Support 162 Station Service 1329 Unit Reliability 20 Water Control	1 Operations Support 14 Station Service 310 Unit Reliability 3 Water Control

Consequence

Condition: 0 → 10

Risk Level	Low	Medium	High

Current Lost Generation Risk

Failure likelihood and consequence information is further evaluated to quantify the expected value of lost generation as Lost Generation Risk.

- Equipment condition correlates to a probability of failure for each component.
- These probabilities are multiplied by the lost generation consequence for each component to calculate the Lost Generation Risk (LGR), i.e., the replacement power cost risk associated with a run-to-failure strategy.

The current LGR for the system is about 702 aMW, up from 587 aMW two years ago, primarily a result of lower condition ratings and availability for Grand Coulee and McNary.

Current Lost Generation Risk by Class and Plant

66 percent of current LGR is in the Main Stem Columbia class (460 aMW).

Grand Coulee has 179 aMW of LGR, attributable mostly to the condition of generator windings, transformers, exciters, and in the Third Powerplant, turbines.

McNary has 153 aMW of LGR, driven by several factors:

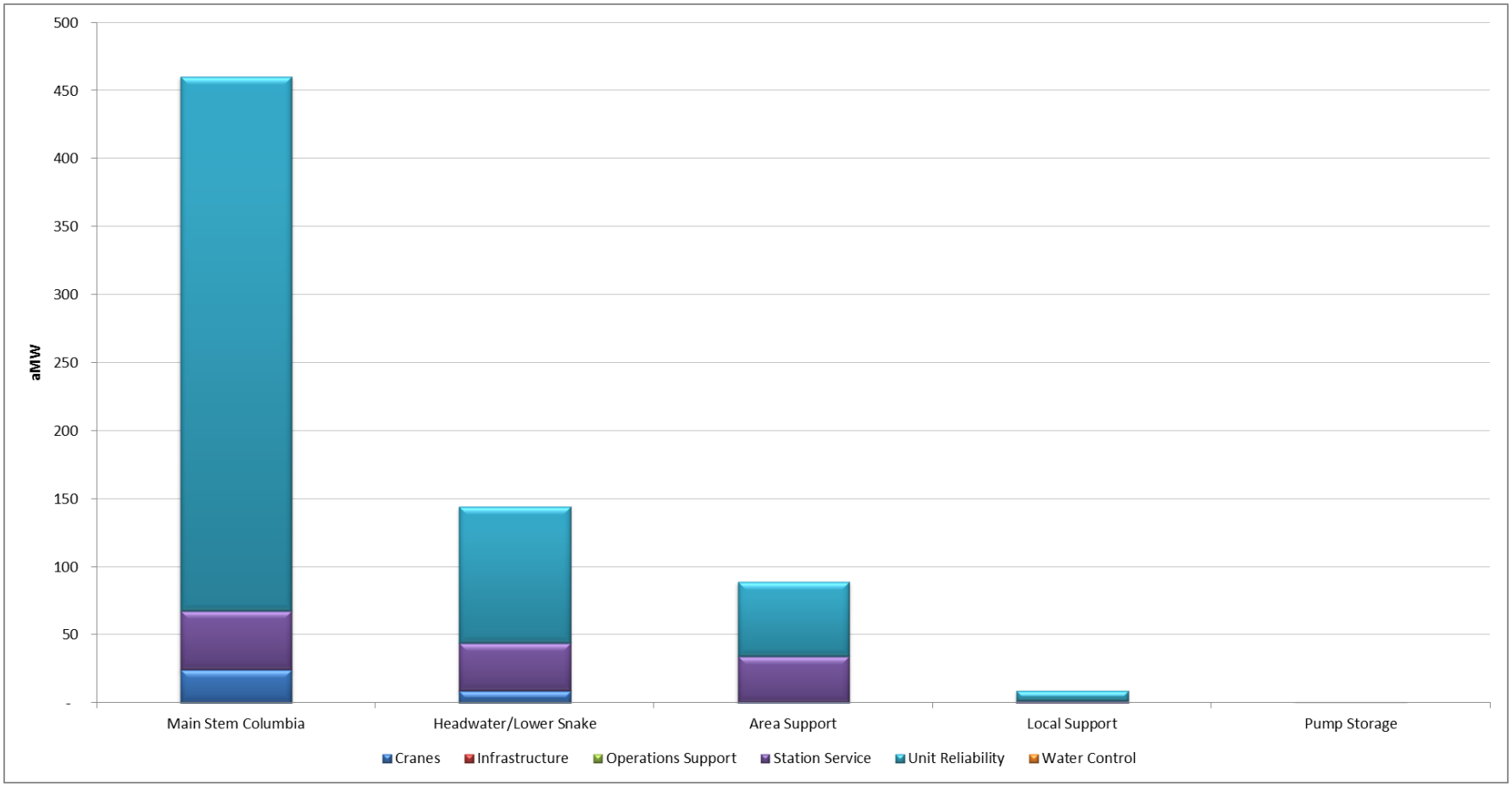
- Generally poor condition of generator stators, turbines, governors, and exciters;
- Many pieces of equipment at risk; and,
- It is a hydraulic bottleneck on the lower river, which results in high lost generation in the event of an outage.

Chief Joseph has 53 aMW of LGR driven mostly by the condition of turbines, windings, governors, and exciters.

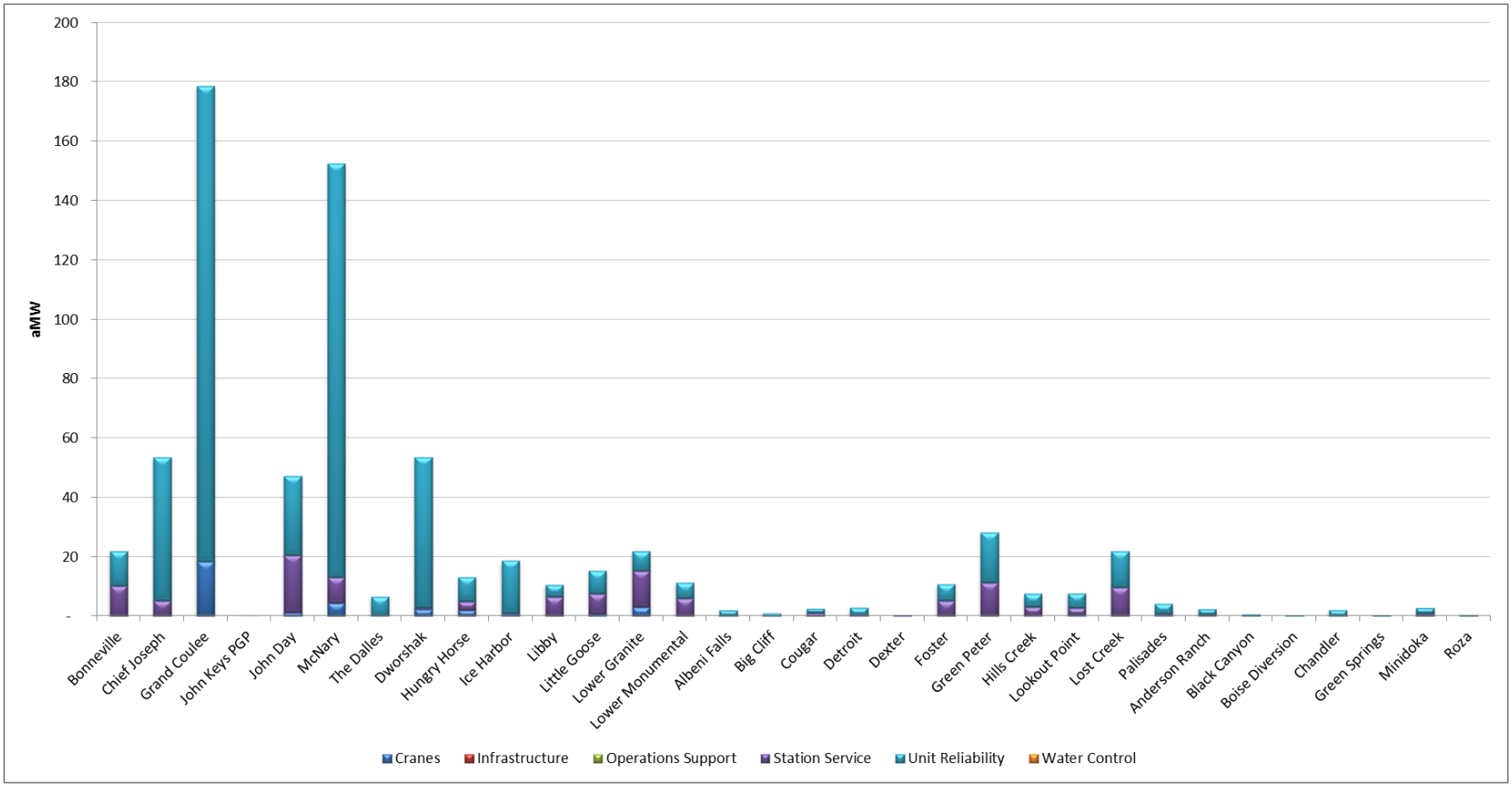
John Day and Dworshak also have LGR of about 50 aMW (turbines and windings).

Most other plants have LGR of less than 30 aMW.

Current Lost Generation Risk by Strategic Class



Current Lost Generation Risk by Plant



4. Hydro Investment Plan

Hydro Investment Plan

Investments to maintain equipment reliability are less about "if" than "when" to make repairs or replacements.

This 2016 Hydro Asset Strategy takes a risk-based approach to identifying the optimum time for making new investments, consistent with the approach used for the 2012 and 2014 strategies. A detailed explanation of the prioritization logic is included in Appendix B.

The strategy is consistent with Bonneville's asset management policy, which states:

- *BPA will invest in, maintain, and operate assets to:*
  - *Meet reliability standards, availability requirements, regional adequacy guidelines, efficiency needs, environmental requirements, safety and security standards, and other requirements; and*
  - *Minimize the life cycle costs of assets when practical.*

Costs Considered in the Strategy

The Hydro Investment Plan covers forecasted O&M, the committed investment program, and new investments to maintain and improve the reliability of electrical and mechanical plant equipment.

Because O&M costs are primarily labor related, and the currently committed investment program is already vetted and underway, the focus of the Hydro Investment Plan is on new investments not yet decided upon.

The O&M program forecast and risk based approach to identifying new capital investments reasonably cover costs necessary for addressing business continuity requirements, including sparing strategies for critical equipment.

This strategy improves the coverage of water control features over that identified in the 2012 strategy.

Costs Not Considered in the Strategy

John W. Keys III Pump Generating Plant

- Keys is a pump storage facility, part of the Grand Coulee Project. Pump-Generating Units 7-8 and 9-12 were commissioned in 1973 and 1983-4, respectively.
- The plant is near end-of-life, much of the unit and balance-of-plant equipment is worn or becoming obsolete.
- Capital costs for base level reliability improvements are estimated at about $100 million.

No costs are included for additional generating units at Libby, John Day, or Dworshak.

Fish facilities funded under Columbia River Fish Mitigation are aging. Initial costs of these facilities are funded under appropriations and reimbursed by Bonneville. Costs for repairs and replacements of these facilities are not covered in this strategy.

Cost also excluded are those for rebuilding or replacing dam safety civil features which are typically funded through appropriations, a share of which is reimbursed by Bonneville. For the focus period of this strategy, the exclusion of costs for dam safety is not expected to materially affect the funding need forecast. However, as the hydro system continues to age, anticipating funding needs for dam safety will require more explicit attention in future strategies.

Elements of Lifecycle Cost

Equipment Replacement Cost: Unique for each equipment type.

Incremental Equipment Failure Cost: Incremental replacement cost due to collateral damage and to planning, procurement and scheduling inefficiencies. Used to calculate Direct Cost Risk.

Replacement Power Cost: The annual generation at risk for the marginal ("least used") unit at each plant multiplied by the expected additional outage in years for each equipment type to determine the amount of lost generation if that equipment fails.

CO2 Cost: CO2 emissions produced by a natural gas-fired combustion turbine to replace generation not produced by a failed hydro unit.

Replacement Power Cost and CO2 Cost are used to calculate Lost Generation Risk.

Economics of Risk Intervention at Different Points in Time

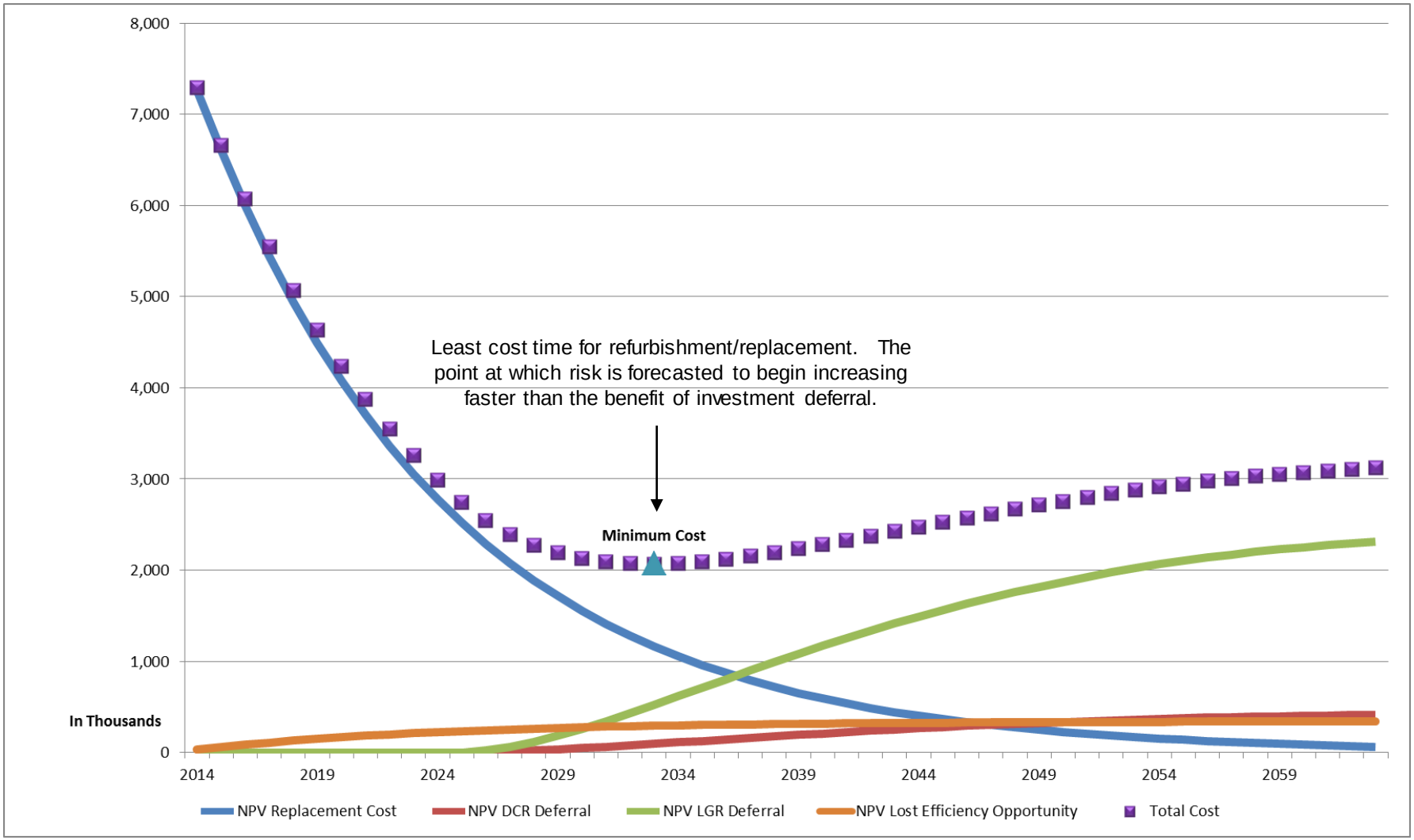
Without corrective action (intervention), equipment condition degrades over time. As equipment condition degrades, the likelihood (and risk) of equipment failing to perform as expected increases.

Four factors influencing the economics of risk intervention are outlined in the diagram on the next page. All curves show the present value of costs over time.

- **Replacement Cost** – Typically, the longer the replacement can be deferred, the lower the present value of its cost.
- **Direct Cost Risk (DCR)** – If equipment fails during the deferral period, intervention costs may be incrementally higher for collateral damage and planning, procurement, and scheduling inefficiencies (overtime, emergency hiring, contract premiums, etc.). This cost risk increases as equipment condition degrades over time.
- **Lost Generation Risk (LGR)** – Equipment failure may also result in longer outages and, thus, more lost generation than if replaced on a planned basis. LGR also increases as equipment condition degrades over time.
- **Lost Efficiency Opportunity (LEO)** – Some equipment replacements (turbine runners, transformers and generator windings) reduce efficiency losses. Deferring replacement results in a lost opportunity to capture increased generation from higher efficiency equipment.

The **Total Cost** is the present value sum of replacement costs, risk costs and LEO. The cost minimum on this curve is the point at which financial risk is forecasted to begin growing faster than the benefit of investment deferral and represents the optimum time to forecast replacement to minimize lifecycle cost.

Present Value Cost of Intervention at Different Points in Time



Assumptions Used in Modeling

Assumption	Value	Source	Comment
Discount rate	12.0 percent	BPA Finance	10 percent real
Inflation rate	1.7 percent	BPA Finance	Average annual rate, 20-yr forecast
Forward energy price curve	20-yr, by month, HLH, LLH, flat	BPA Power Services Resource Program	Includes spot prices and a component for long-term firm capacity consistent with rate case demand rate.
Equipment cost	Varies by equipment type	FCRPS hydro program	Based on industry cost data
Real cost escalation	0 percent	BPA Finance	Global Insight
Failure curves	Varies by equipment type	BPA Federal Hydro	Based on industry data for certain equipment
Outage duration for LGR	Varies by equipment type	FCRPS hydro program	Based on industry experience
Environment and safety	Risk	BPA Federal Hydro	Treats all high risk items as “must do”
Value of avoided CO2	$35/ton	BPA Corporate Strategy	Based on Presidential Directive
Alternative resource for hydro lost generation	Natural gas-fired Combined-Cycle Combustion Turbine	BPA Agency Asset Management	0.48 tons of CO2 per MWh of generation

Modeling Funding Constraints

For this strategy, each equipment component is evaluated in yearly time steps and forecasted for refurbishment/replacement if it meets either of the following criteria:

- First, if its condition places it into a high risk category for safety or environment.
- Second, if financial risk costs are increasing faster than investment deferral benefits, i.e., the equipment component is at the cost minimum.

Once the equipment component is selected for investment, its condition resets to 10 at the end of the investment period. Its condition then begins to degrade at the identified degradation rate.

If an annual funding limitation is defined, then the prioritization proceeds as follows:

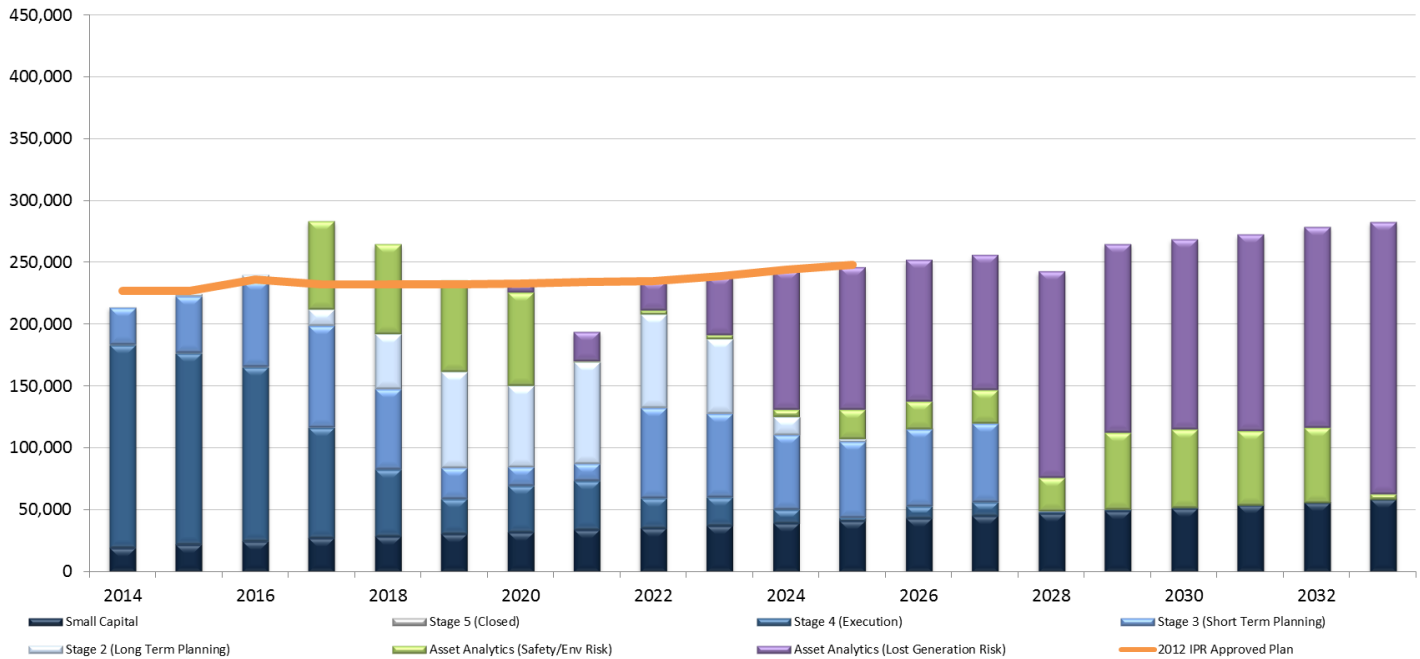
- Committed projects proceed as scheduled;
- High risk safety and environmental projects are selected as previously described;
- Financial risk driven projects are selected as described until an annual funding limitation is reached, after which investment in equipment in which financial risk is increasing the least is deferred until the following year, where it is re-evaluated using the same prioritization logic.

When funding constraints are applied, Total Cost for the system (system cost) increases because new investments are deferred past their cost minima.

Capital Forecast
2014 – 2033

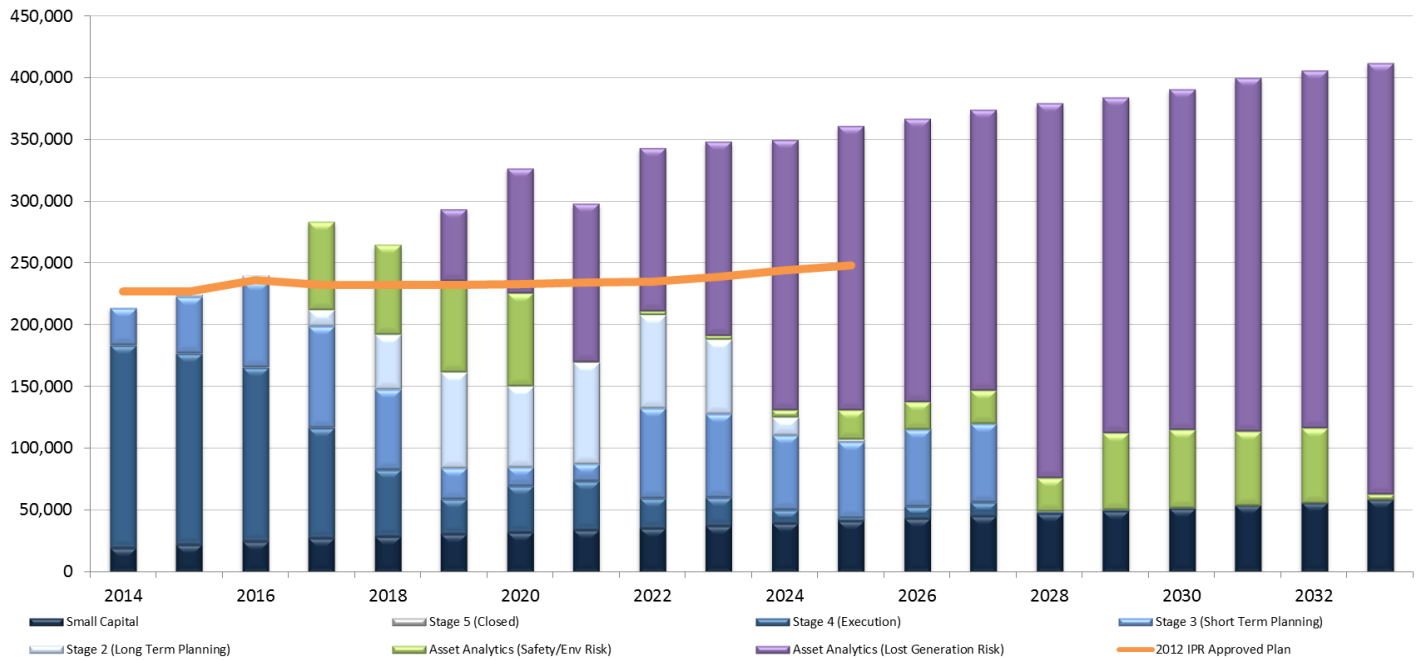
Modeling funding constraints in this strategy has little effect on the 2014 – 2017 program. Nearly all available funding is committed during this period, so there is limited ability to turn these projects off without significant negative financial consequences. Funding constraints affect the number of projects that can be undertaken 5 to 20 years into the future to mitigate forecasted growth in risk.

The following graph shows modeling results when constrained to the 2012 IPR Approved Plan budget level (2012 Access to Capital level).



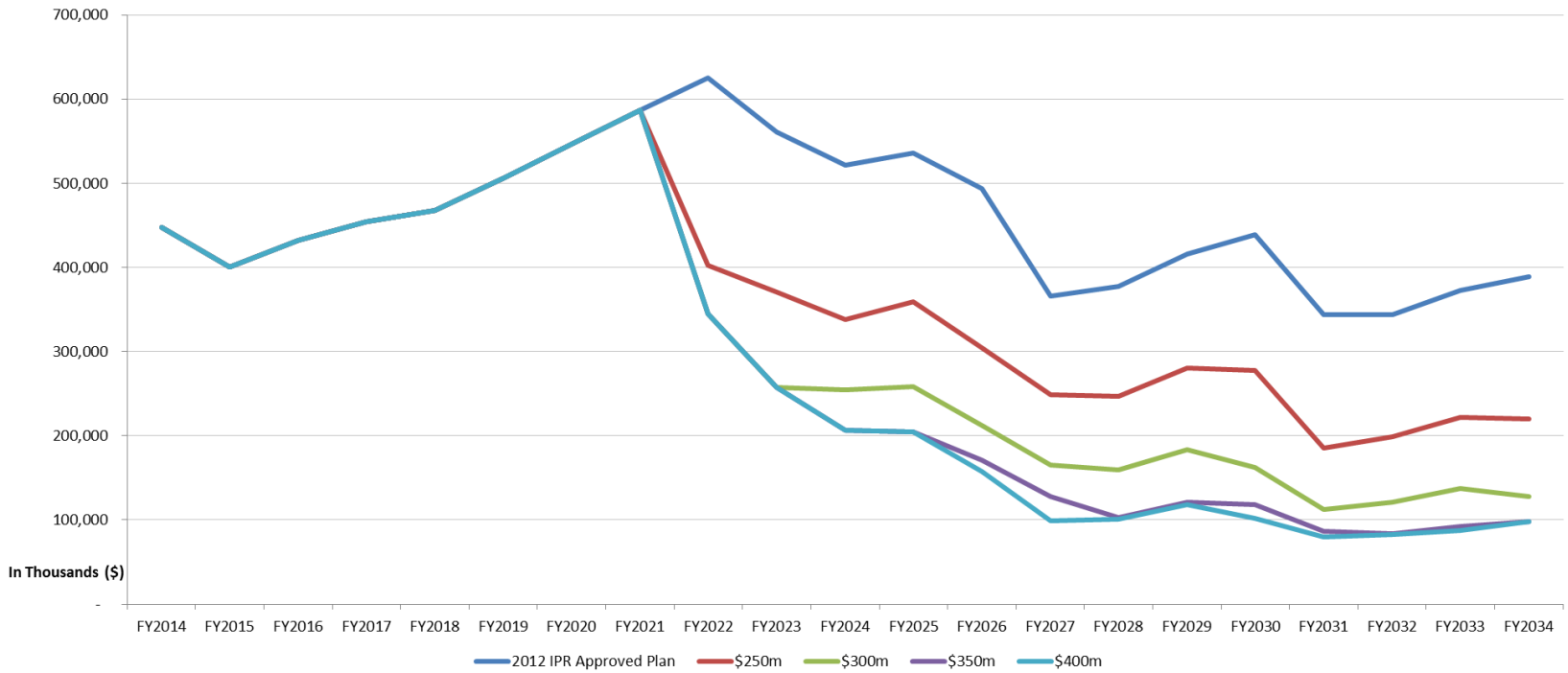
Other Funding Constraint Scenarios

Funding constraints require that some investments are delayed beyond their cost minimum, resulting in higher risk and Total Cost for the system. For the strategy, we looked at the impact of various higher funding levels and their associated reduction in risk. Several sensitivities were run with consistent funding levels through 2017, then ramping up at $25 million per year until a trigger funding level was reached, after which it was held constant in real dollars for the remainder of the 50-year study period. A funding stream for a $300 million trigger level is shown below.



Lost Generation Risk Forecast for Different Funding Levels

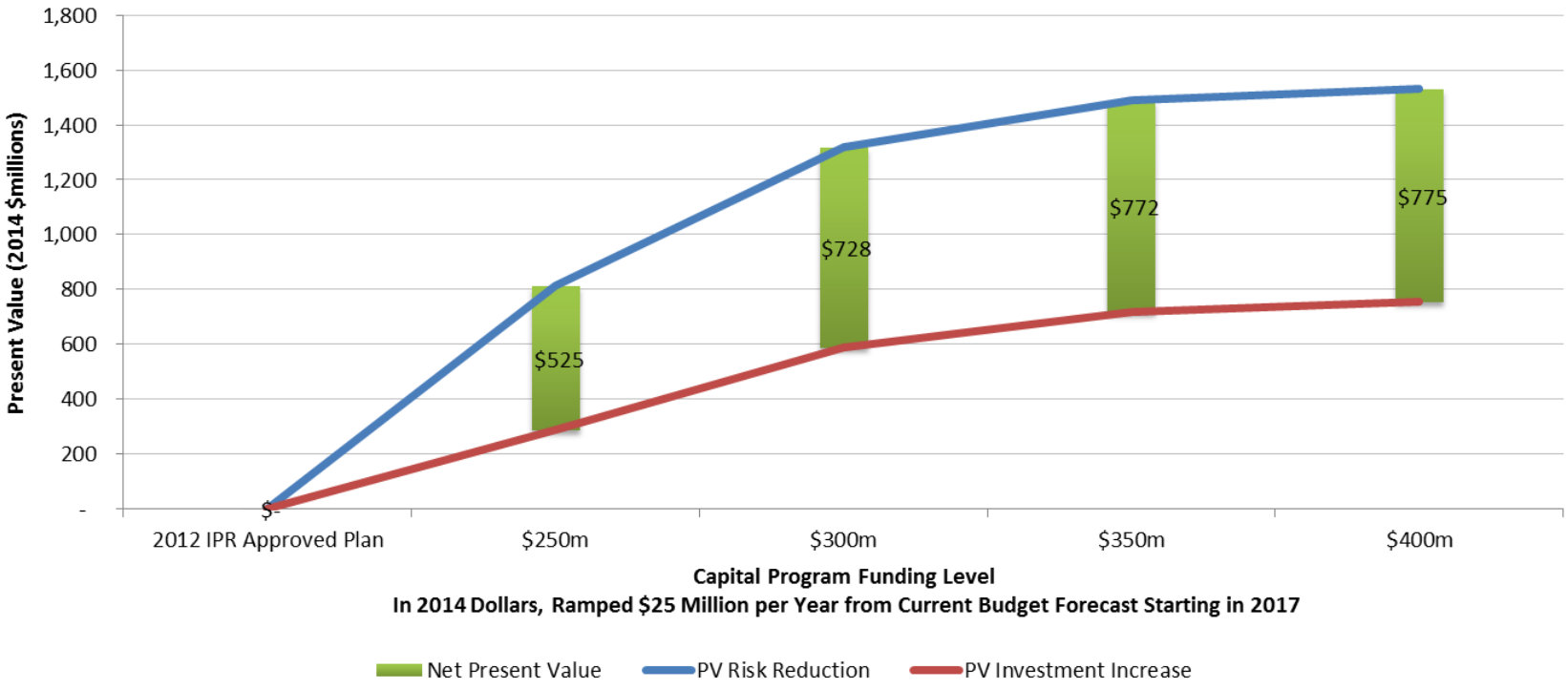
The capital program is fully committed through 2017. New investments started after then do not affect condition and risk for several years until work is completed. Therefore, all funding scenarios result in a similar risk profile thru 2021, after which higher funding levels reduce risk more quickly. At the 2012 IPR Approved Plan program level, risk increases thru 2022 and returns to current levels by 2027 and beyond. Fairly dramatic risk reductions are seen in higher funding scenarios, with a $300 million per year program reducing risk to about half of the current level by 2023 and by 75 percent in 2031.



Net Present Value of Different Funding Levels

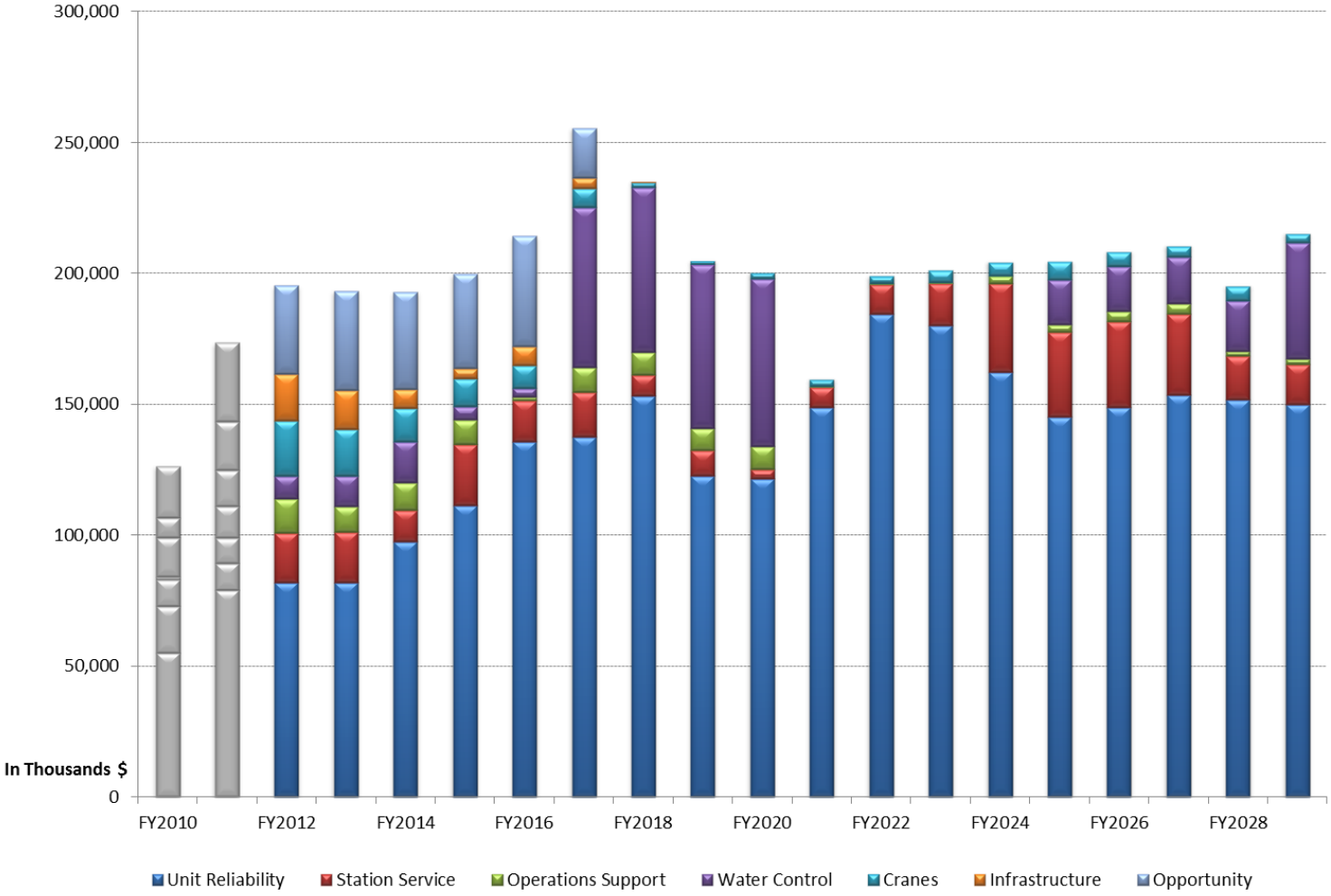
12 Percent Discount Rate

The net present value (NPV) of higher funding scenarios increases fairly dramatically up to $300 million per year (2014 dollars), after which it increases more slowly. For a $300 million scenario, the present value of costs increases by $600 million, but the present value of risk increases by more than $1.3 billion, resulting in a NPV of $728 million relative to the current 2012 IPR Approved Plan (2012 Access to Capital Strategy). A $300 million per year program level is also near the investment benchmark median for a comparable system (see slide 23).



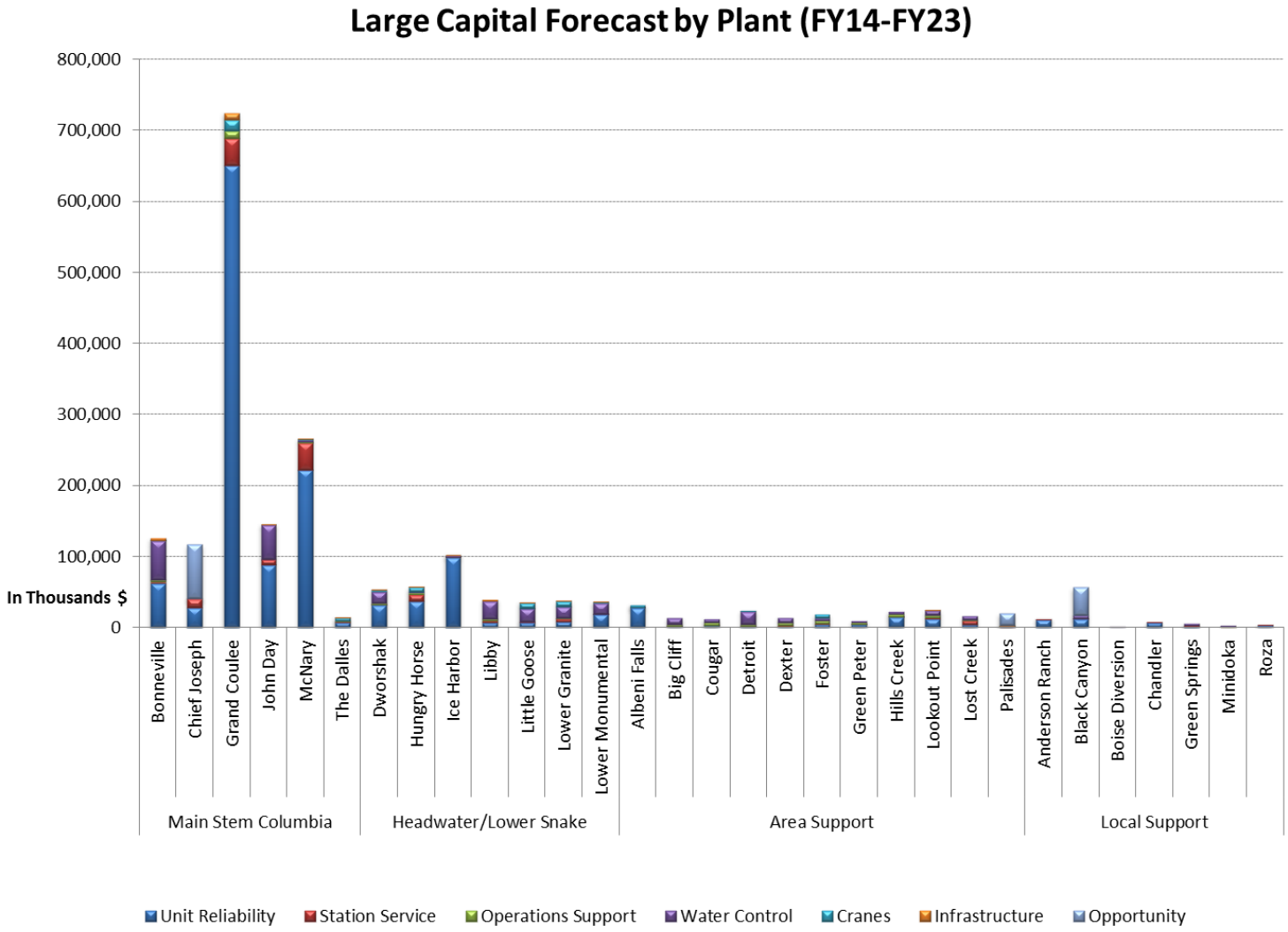
Large Capital Plan by Equipment Category

2012 Access to Capital Funding Level



Large Capital 10-Year Plan by Plant

2012 Access to Capital Funding Level



The Plan has the Following Effects:

2012 Access to Capital Funding Level

Condition

- The average condition of equipment in 2024 is forecasted to decline to about 6.3, with average condition at Grand Coulee and McNary staying above 7.0.

Age

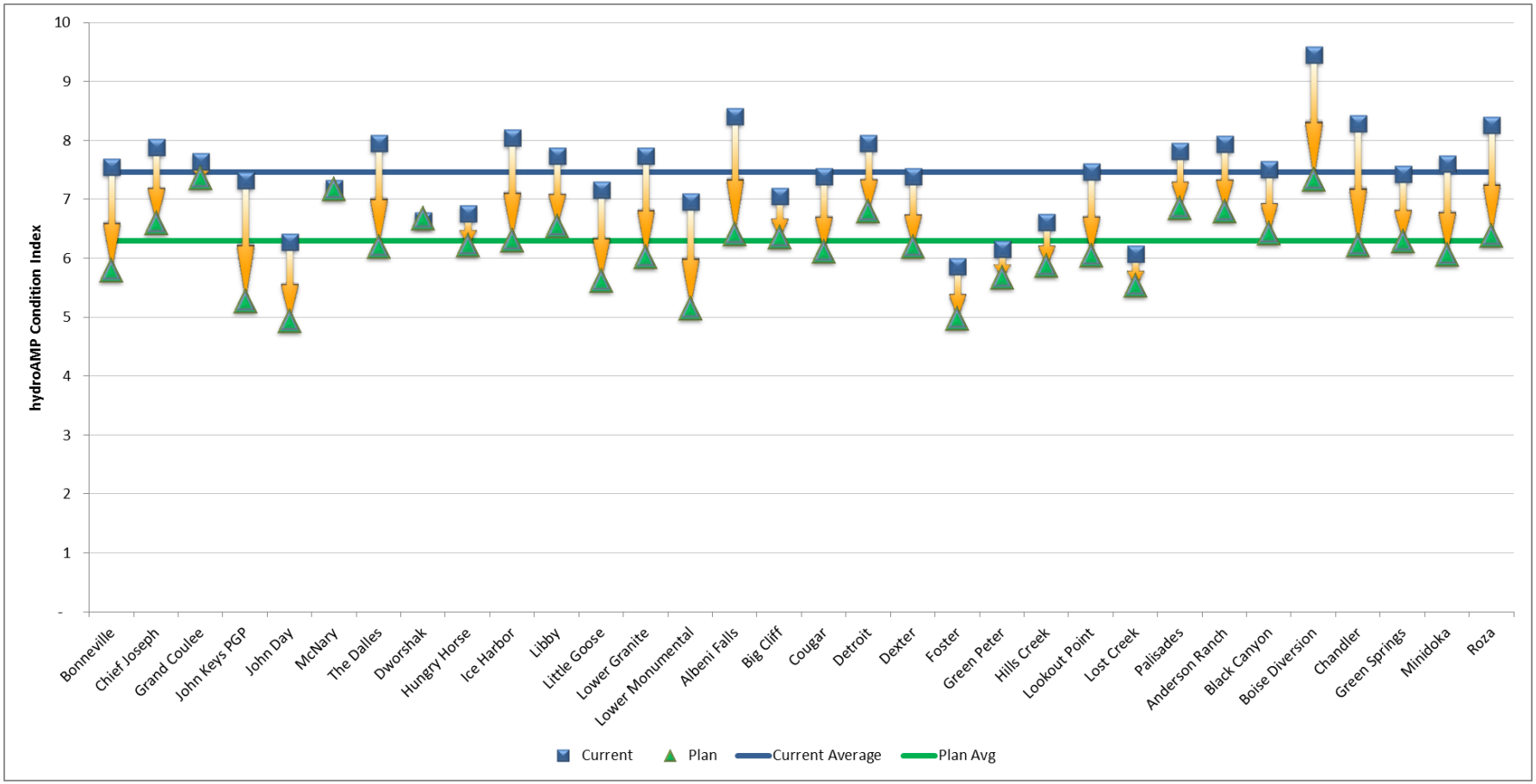
- In 2024, the average age as a percent of design life is forecasted to increase slightly to about 80 percent.
- Average age increases for operations support and infrastructure categories, in large part because the asset planning modeling algorithm does not have a good mechanism for identifying investment need in these categories.

Lost Generation Risk

- LGR is forecasted to increase from 702 aMW today to 818 aMW in 2024.
  - Grand Coulee: 171 aMW, primarily due to turbine runners and generators in the Third Power Plant.
  - John Day: 105 aMW, primarily windings, transformers and station service.
  - Chief Joseph: 83 aMW, primarily generator windings.
  - McNary: 59 aMW, primarily governors.
  - Bonneville: 50 aMW, primarily windings and station service.

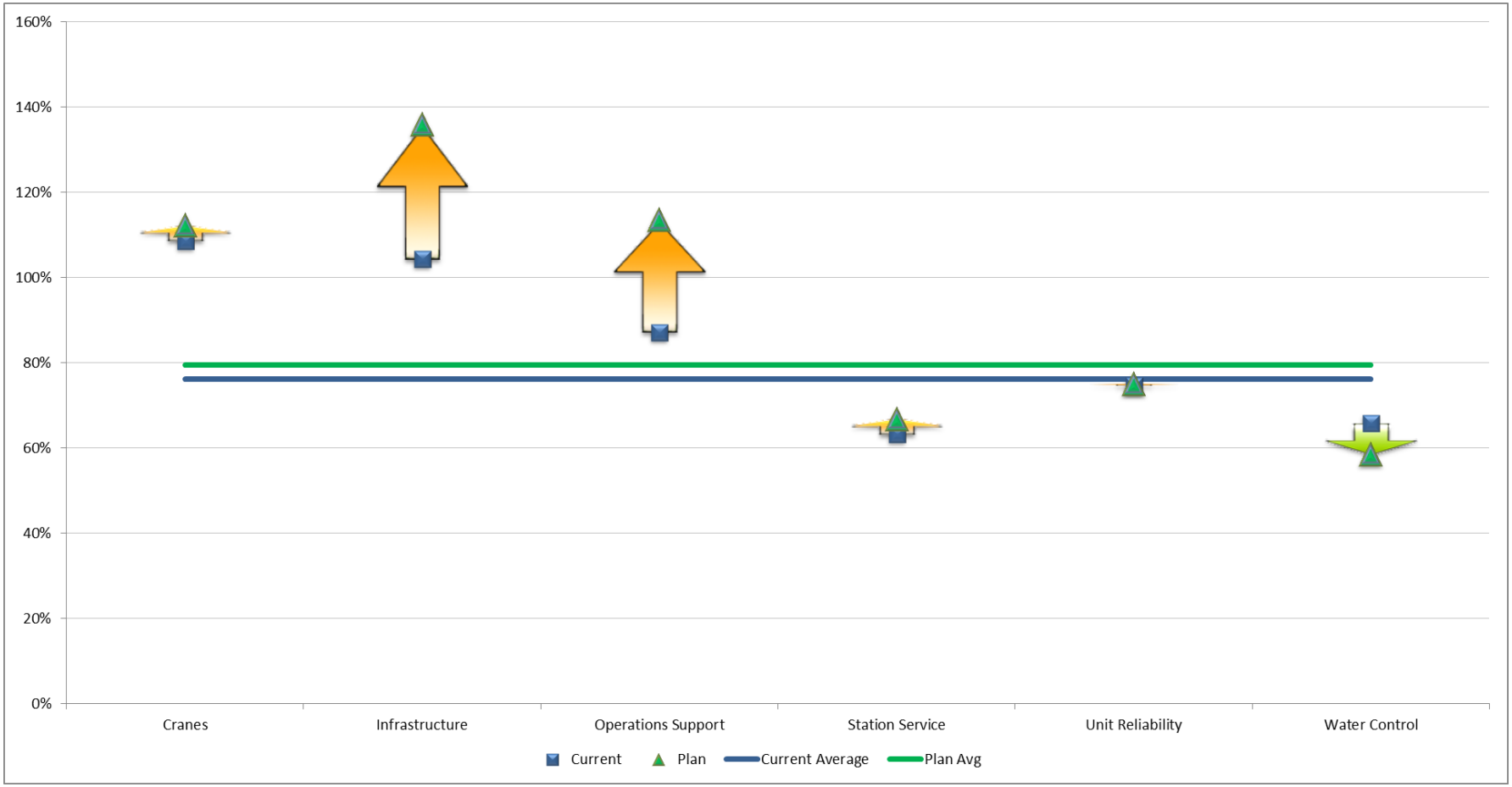
Condition by Plant in 2024: All Equipment

2012 Access to Capital Funding Level



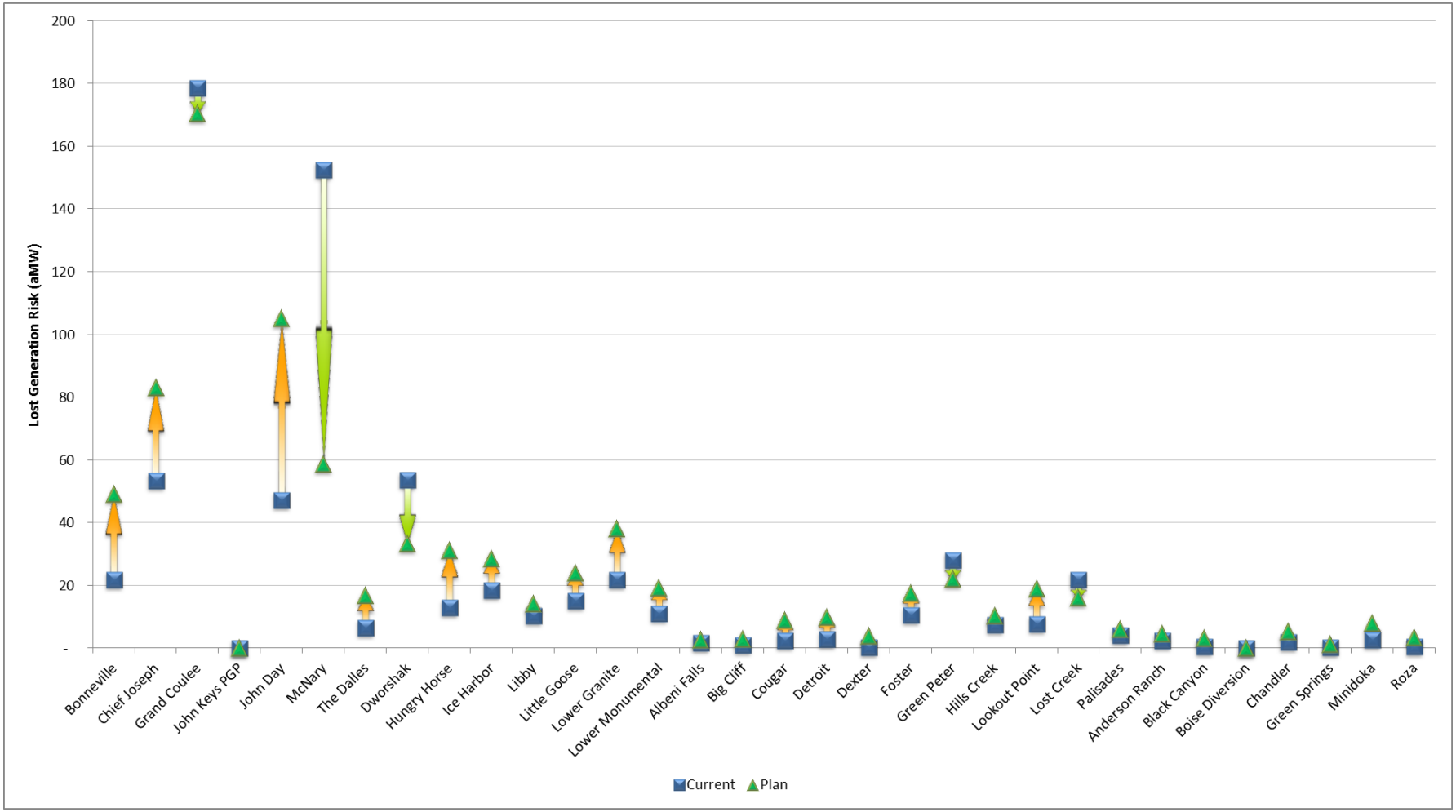
Average Age in 2024: All Equipment

2012 Access to Capital Funding Level



Lost Generation Risk by Plant in 2024

2012 Access to Capital Funding Level



Economics of the Plan

2012 Access to Capital Funding Level

Levelized Incremental Cost (excludes sunk costs)

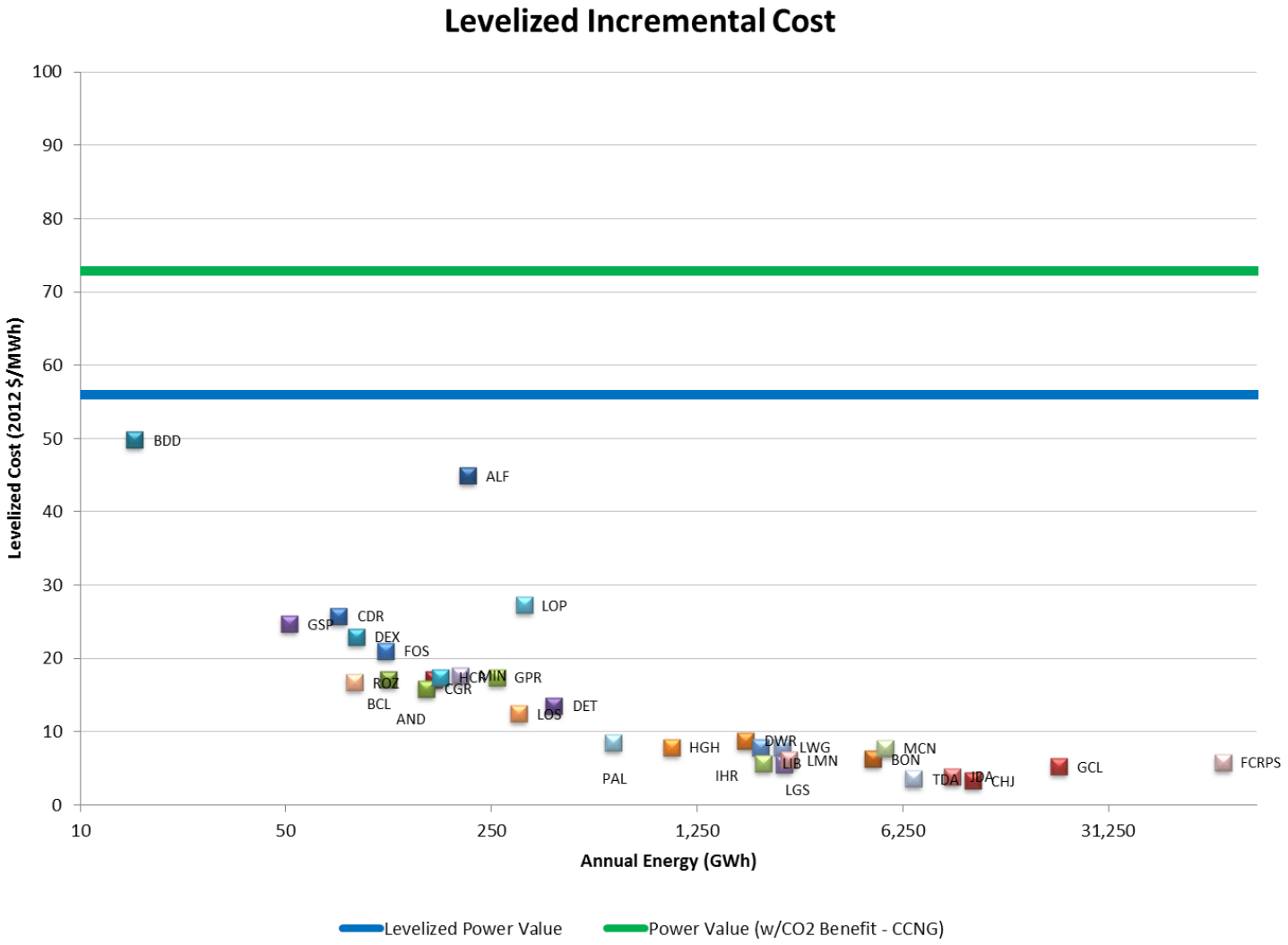
- The levelized incremental cost includes all forecasted new capital investment and O&M expenses through 2033.
- The levelized incremental cost is $5.90/MWh (20212 dollars) for the FCRPS hydro system and below $9 per MWh for all plants in the Main Stem Columbia and Headwater/Lower Snake strategic classes.
- Most other plants have levelized incremental costs below $30 per MWh.
- Forecasted levelized costs for each plant are below the value of power generated by the facility, represented by the blue and green lines on the chart.

Levelized Fully Allocated Cost (includes sunk costs)

- When adding the sunk investment in the hydro system to incremental O&M and investment costs, the 20-year levelized fully allocated cost of the hydro system is $9.50 per MWh (2012 dollars).

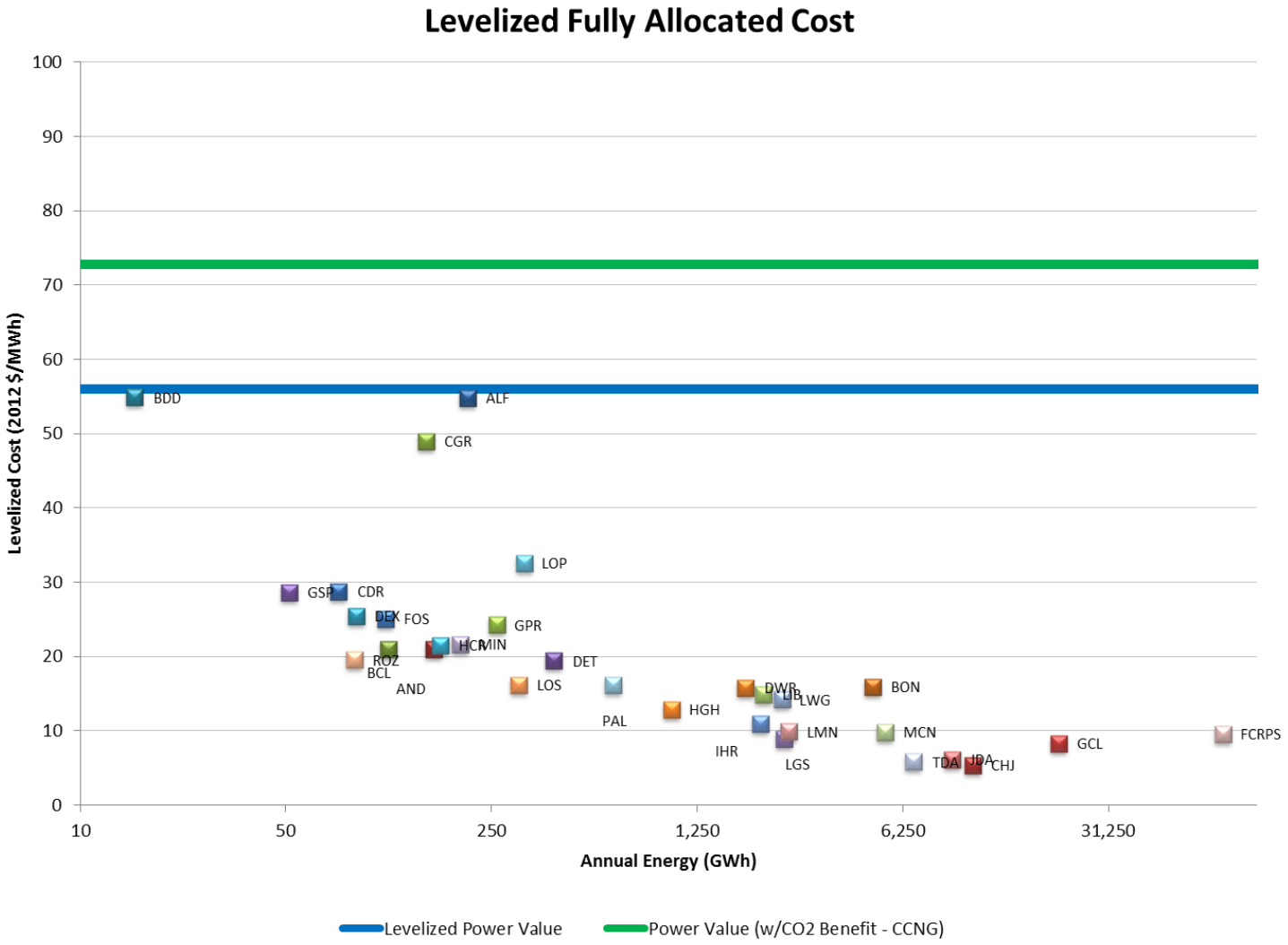
Levelized Incremental Cost

FY2014 – FY2033 Expense and Capital Programs



Levelized Fully Allocated Cost

FY2014 – FY2033 Expense and Capital Programs plus Net Utility Plant (sunk costs)



5. Summary

Summary

Approach and Scope

Investments to maintain equipment reliability are less about “if” than “when” to make repairs or replacements.

The 2016 Hydro Asset Strategy takes a risk-based approach to identifying the optimum time for making reliability investments, consistent with the approach used for the 2012 and 2014 strategies.

It identifies condition and risk implications of the currently committed hydro investment program and new investments prioritized around minimizing lifecycle cost.

The strategy includes electrical and mechanical equipment on hydropower specific and joint-use features, but excludes costs for large dam safety civil features and repairs and replacements of aging hatchery and fish passage facilities constructed for Columbia River Fish Mitigation and the Lower Snake Compensation Plan.

The strategy also excludes an evaluation of specific issues that may result in new strategic initiatives, e.g., capacity expansion opportunities, pumped storage and automation. Studies required for these issues are detailed and unique. If and when those studies develop, they will be summarized and reflected in future strategies.

Summary
Results

BPA's Access to Capital Strategy governs the plan derived in this strategy.

- The 2012 IPR Approved Plan capital program averaging $235 million per year risk by 50 percent through 2022, after which risk declines to current levels by 2027 and beyond. This plan represents a sub-optimal level of future investment for adequate business continuity and cost effective reliability.
- The need to manage near term capital borrowing may result in higher long term system cost by increasing the risk of unit outages and replacement power costs. The system cost of the 2012 IPR Approved Plan is forecasted to be above that of higher capital funding scenarios.
- A $235 million program level is about 75 percent of what is suggested by strategy planning analyses and cost benchmarking studies.
- The investment plan derived in this strategy does not include costs for modernization of John W. Keys Pump Generating Plant or other uncommitted economic opportunity investments (e.g., additional units at Dworshak, Libby, or John Day).
- A program consistent with the 2012 IPR Approved Plan through 2017, but which then ramps to $300 million per year (2014 dollars), is projected to reduce risk by 50 percent in 2023 and 75 percent by 2031 with a net present value of $728 million relative to a $235 million program.

Under the 2012 IPR Approved Plan, the 20-year levelized fully allocated cost of the hydro system is forecasted to be $9.50 per MWh (2012 dollars).

The Capital Workgroup defines and implements a capital program consistent with this strategy.

Appendix A

Capital Program Detail

Background

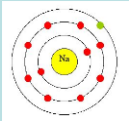
Capital Program

- The capital program is managed by a 3-Agency Capital Workgroup
- The CWG meets six times per year to review and approve new investments
- Capital program managers also meet six times per year to:
  - review investments identified in the asset strategy and, from that, develop a high level plan for out years; and,
  - to do real-time management of active subagreement contracts in order to prioritize and schedule projects within the program budget.

The CWG uses staging to order projects within the program based on each project's level of maturity.

- Stage 4: mature projects that are in flight. Projects are ranked to support real-time management.
- Stage 3: mature projects that are not yet in flight, but are next in line.
- Stage 2: equipment identified in the asset strategy aggregated into first order projects. Schedules are high level and fluid.
- Stage 1: equipment identified in the asset strategy not covered in other stages.

Capital Program Planning and Implementation Criteria

Planning Criteria	Stage 	Implementation Criteria					
Approved projects in flight	4	Under contract (non-deferrable)	Priority, Critical, Essential (life safety, environmental or regulatory compliance, etc) (non-deferrable)	Phase 2 approved, contract advertized but not awarded (non-deferrable)	Phase 2 approved, contract not advertized (deferrable)	Phase 1 underway (exploratory studies to refine project Phase 2 scope, cost and schedule) (deferrable)	Phase 1 approved but not yet underway (exploratory studies to refine project Phase 2 scope, cost and schedule) (deferrable)
Mature projects not yet approved	3	Refined cost and schedule estimates awaiting funding approval. Consistent with asset strategy	Developing refined cost and schedule estimates				
Equipment identified in the asset strategy aggregated into first order projects	2	Cost and schedule estimates are high level and fluid					
Equipment identified in the asset strategy not covered in other stages	1						

Capital Program Projects
by Plant, Stage and Start Year

Albeni Falls	ALB Reroof Powerhouse	Stage 4 (Execution)	2001
Albeni Falls	ALB Governor (SYS Governor Repl.)	Stage 4 (Execution)	2002
Albeni Falls	ALB GDACS and Spillway	Stage 4 (Execution)	2004
Albeni Falls	ALB Protective Relay Replacement (Phase 1&2)	Stage 4 (Execution)	2006
Albeni Falls	ALB Unit 1 Bulkhead Gate Replacement	Stage 4 (Execution)	2006
Albeni Falls	ALB High Lift Pumps	Stage 4 (Execution)	2007
Albeni Falls	ALB Auxiliary Boards	Stage 4 (Execution)	2008
Albeni Falls	ALB Spillway Crane Modernization (Ph. 1 & Ph. 2)	Stage 4 (Execution)	2009
Albeni Falls	ALB Intake Crane Modernization (Ph. 1 & Ph. 2)	Stage 4 (Execution)	2009
Albeni Falls	ALB DC System Boards & Breakers (Ph. 1 & Ph. 2)	Stage 4 (Execution)	2009
Albeni Falls	ALB Spillway Gate Modifications (Ph. 1&2)	Stage 4 (Execution)	2012
Albeni Falls	ALB Powerhouse Life Safety Alarm System	Stage 4 (Execution)	2013
Albeni Falls	ALB Generator Windings	Stage 2 (Long Term Planning)	2020
Anderson Ranch	AND Station Service Upgrade	Stage 4 (Execution)	2014
Anderson Ranch	AND Turbine Replacement G1 & G2	Stage 3 (Short Term Planning)	2015
Big Cliff	BCL Spillway Bulkhead Gates (Joint)	Stage 4 (Execution)	2009
Big Cliff	BCL Spillway Tainter Gate Rehabilitation	Stage 4 (Execution)	2011
Big Cliff	BCL Digital Governor	Stage 4 (Execution)	2012
Big Cliff	WVY and LOS GDACS_BCL (Phase 1)	Stage 4 (Execution)	2014
Big Cliff	BCL Control Data Link (Phase 1)	Stage 3 (Short Term Planning)	2017
Black Canyon	BCD Units 1 & 2 Upgrades (Phase 1)	Stage 4 (Execution)	2011
Black Canyon	BCD Install Trash Rake System	Stage 4 (Execution)	2011
Black Canyon	BCD Third Unit Installation (Ph. 2)	Stage 4 (Execution)	2015
Black Canyon	BCD Units 1 & 2 Upgrades (Ph 2)	Stage 3 (Short Term Planning)	2014
Black Canyon	BCD Trash Racks & Rake System Replacement	Stage 3 (Short Term Planning)	2016
Black Canyon	BCD Governor Replacement G1 & G2	Stage 2 (Long Term Planning)	2021
Bonneville	BON 1 & 2 Headgates	Stage 4 (Execution)	2000
Bonneville	BON 1 Rehabilitation	Stage 4 (Execution)	2004
Bonneville	BON 2 Exciter Installation	Stage 4 (Execution)	2005
Bonneville	BON Control Room Fire Protection Upgrades	Stage 4 (Execution)	2006
Bonneville	BON 2 Gantry Crane 7 Rehab.	Stage 4 (Execution)	2006
Bonneville	BON 2 Station Service Repl.	Stage 4 (Execution)	2007
Bonneville	BON 1 Tailrace Deck & Crane	Stage 4 (Execution)	2007
Bonneville	BON 1 Elevators 1 & 2 Replacement	Stage 4 (Execution)	2009
Bonneville	BON 1 Main Unit Breaker & Station Service Reconfiguratio	Stage 4 (Execution)	2010
Bonneville	BON 2 Digital Governors (Ph. 1 and 2)	Stage 4 (Execution)	2011
Bonneville	BON 2 Generator Protective Relay Replacement	Stage 4 (Execution)	2011
Bonneville	BON 1 & 2 Vibration and Air Gap Monitoring	Stage 4 (Execution)	2012
Bonneville	BON 1 & 2 Governor Oil Filtration System	Stage 4 (Execution)	2012
Bonneville	BON 2 Transformer Improvements (Ph. 1)	Stage 4 (Execution)	2012
Bonneville	BON GSU Instrument Transformers (Phase 1)	Stage 4 (Execution)	2013
Bonneville	BON Unit 11 Generator Repair	Stage 4 (Execution)	2013
Bonneville	BON 1 Auto Synchronization Upgrade	Stage 3 (Short Term Planning)	2014
Bonneville	BON 1 Main Unit Breaker Replacement & Station Service R	Stage 3 (Short Term Planning)	2015
Bonneville	BON GSU Instrument Transformers (Phase 2)	Stage 3 (Short Term Planning)	2015
Chandler	CDR Exciter Repl.	Stage 4 (Execution)	2007
Chandler	CDR KY1A Transformer & Breaker Repl	Stage 4 (Execution)	2009
Chandler	CDR Rewind Units 1 & 2	Stage 3 (Short Term Planning)	2014
Chief Joseph	CHJ Powerhouse Cranes (Bridge & End Trucks)	Stage 4 (Execution)	1999

Chief Joseph	CHJ SS Transformer	Stage 4 (Execution)	2000
Chief Joseph	CHJ SS Governor	Stage 4 (Execution)	2000
Chief Joseph	CHJ SS Breaker Repl. (SYS SS Brk.)	Stage 4 (Execution)	2000
Chief Joseph	CHJ MUB (SYS)	Stage 4 (Execution)	2000
Chief Joseph	CHJ CO2 System Repl.	Stage 4 (Execution)	2001
Chief Joseph	CHJ Sup. Cont. Consoles Replacement	Stage 4 (Execution)	2005
Chief Joseph	CHJ Emergency Notification	Stage 4 (Execution)	2006
Chief Joseph	CHJ Units 17-27 Exciter Repl.	Stage 4 (Execution)	2007
Chief Joseph	CHJ Protective Relay Replacement	Stage 4 (Execution)	2007
Chief Joseph	CHJ Governor (SYS Governor Repl.)	Stage 4 (Execution)	2007
Chief Joseph	CHJ Automatic Synchronizer Replacement	Stage 4 (Execution)	2008
Chief Joseph	CHJ DC and Preferred AC Upgrade	Stage 4 (Execution)	2009
Chief Joseph	CHJ Generator Cooling System Upgrades	Stage 4 (Execution)	2009
Chief Joseph	CHJ Generator Brake System Repl	Stage 4 (Execution)	2009
Chief Joseph	CHJ Power House HVAC Upgrade	Stage 4 (Execution)	2015
Chief Joseph	CHJ Fire Detection and Protection - Facility Plant	Stage 2 (Long Term Planning)	2015
Chief Joseph	CHJ SQ 4&5, SU 17-27 Replacement (units 17-27 480V)	Stage 2 (Long Term Planning)	2017
Chief Joseph	CHJ T01 Transformer Replacement	Stage 2 (Long Term Planning)	2018
Cougar	COU Exiter Replacement	Stage 4 (Execution)	2000
Cougar	COU Powerhouse Upgrade	Stage 4 (Execution)	2001
Cougar	COU Generator Fire Protection & HVAC	Stage 4 (Execution)	2005
Cougar	COU/HCR (COU Only) Powerhouse and Transformer Oil W	Stage 4 (Execution)	2009
Cougar	COU Protective Relays Replacement	Stage 4 (Execution)	2009
Cougar	CGR Digital Governors	Stage 4 (Execution)	2012
Cougar	WVY and LOS GDACS_CGR (Phase 1)	Stage 4 (Execution)	2014
Detroit	DET Repl. Windings (includes BCL) & Oil Repl.	Stage 4 (Execution)	2001
Detroit	DET Remote Control (includes BCL)	Stage 4 (Execution)	2002
Detroit	DET Crane Refurbishment (includes BCL)	Stage 4 (Execution)	2003
Detroit	DET Spare Transformer	Stage 4 (Execution)	2004
Detroit	DET/BCL Generator Fire Protection & HVAC	Stage 4 (Execution)	2005
Detroit	DET Electric Reliability Upgrades	Stage 4 (Execution)	2006
Detroit	DET Emergency Engine Gen. (includes BCL)	Stage 4 (Execution)	2007
Detroit	DET/BCL Fire Protection & HVAC	Stage 4 (Execution)	2009
Detroit	DET Powerhouse and Transformer Oil Water Separator (Ph	Stage 4 (Execution)	2012
Detroit	DET Digital Governor	Stage 4 (Execution)	2012
Detroit	WVY and LOS GDACS_DET (Phase 1)	Stage 4 (Execution)	2014
Dexter	DEX Spillway Bulkhead Gates (Joint)	Stage 4 (Execution)	2009
Dexter	DEX Spillway Tainter Gate Repair	Stage 4 (Execution)	2011
Dexter	DEX Powerhouse and Transformer Oil Water Separator (Ph	Stage 4 (Execution)	2012
Dexter	DEX Digital Governors	Stage 4 (Execution)	2012
Dexter	DEX Electrical Reliability Upgrades (Phase 1)	Stage 4 (Execution)	2013
Dexter	WVY and LOS GDACS_DEX (Phase 1)	Stage 4 (Execution)	2014
Dworshak	DWK Emergency Notification (Pagers)	Stage 4 (Execution)	2006
Dworshak	DWK PH Bridge Cranes	Stage 4 (Execution)	2008
Dworshak	DWK Elevators	Stage 4 (Execution)	2008
Dworshak	DWR U3 Standby Generator Guide Bearing and Oil Cooler /	Stage 4 (Execution)	2011
Dworshak	DWR DNFH Boiler Control Replacement (Phase 1 & 2)	Stage 4 (Execution)	2011
Dworshak	DWR Powerhouse HVAC Upgrade (Phase 1 and 2A)	Stage 4 (Execution)	2012
Dworshak	DWR Unit 3 Rehabilitation	Stage 4 (Execution)	2013

Capital Program Projects
by Plant, Stage and Start Year

Dworshak	DWR Powerhouse HVAC Upgrade (Phase 2)	Stage 3 (Short Term Planning)	2014
Dworshak	DWR Upgrade Telephone Switch and System	Stage 3 (Short Term Planning)	2014
Dworshak	DWR Upgrade Telephone Switch and System (Ph 2B)	Stage 3 (Short Term Planning)	2015
Dworshak	DWR Spillway Gates Fit For Svc Recommendations	Stage 2 (Long Term Planning)	2015
Dworshak	DWR Exciter Replacement (Phase 1)	Stage 2 (Long Term Planning)	2016
Dworshak	DWR Tailrace Crane Rehab	Stage 2 (Long Term Planning)	2016
Dworshak	DWR Exciter Replacement (Phase 2)	Stage 2 (Long Term Planning)	2017
Dworshak	DWR Transformer Separation (Main and SS)	Stage 2 (Long Term Planning)	2017
Dworshak	DWR Unit 3 Spare Winding	Stage 2 (Long Term Planning)	2018
Foster	FOS Repl. (SYS Exciter)	Stage 4 (Execution)	2000
Foster	FOS Stop Log Fabrication	Stage 4 (Execution)	2009
Foster	FOS Digital Governors	Stage 4 (Execution)	2011
Foster	FOS Powerhouse and Transformer Oil Water Separator (PI	Stage 4 (Execution)	2012
Foster	FOS Main Unit Breakers Replacement - Ph 1	Stage 4 (Execution)	2013
Foster	FOS Bridge Crane Rehabilitation (Phase 1)	Stage 4 (Execution)	2013
Foster	WVY and LOS GDACS_FOS (Phase 1)	Stage 4 (Execution)	2014
Foster	FOS Main Unit Breaker Replacement	Stage 3 (Short Term Planning)	2013
Foster	FOS Bridge Crane Rehabilitation (Phase 2)	Stage 3 (Short Term Planning)	2015
Grand Coulee	GCL CO2 Replacement	Stage 4 (Execution)	1999
Grand Coulee	GCL 22-24 Spare TX & 19-21 Replacement Bank	Stage 4 (Execution)	1999
Grand Coulee	GCL 21 Powerhouse Transformer	Stage 4 (Execution)	1999
Grand Coulee	GCL G1-18 Stator, Winding, Core & Spare	Stage 4 (Execution)	2002
Grand Coulee	GCL SCADA Replacement	Stage 4 (Execution)	2004
Grand Coulee	GCL 11.95 KV Switchgear	Stage 4 (Execution)	2004
Grand Coulee	GCL G1-18 Air Housing Coolers	Stage 4 (Execution)	2006
Grand Coulee	GCL 500 kV Switchyard Relay Replacement	Stage 4 (Execution)	2006
Grand Coulee	GCL TPP Roof Rehabilitation	Stage 4 (Execution)	2006
Grand Coulee	GCL Left/Right Roof Replacement	Stage 4 (Execution)	2007
Grand Coulee	GCL K10 Transf. Bank Repl.	Stage 4 (Execution)	2007
Grand Coulee	GCL G19-24 Exciter Replacement	Stage 4 (Execution)	2007
Grand Coulee	GCL G19-20 236 MVA Transf. Repl. (6 tanks)	Stage 4 (Execution)	2007
Grand Coulee	GCL XRS Switchgear Replacement	Stage 4 (Execution)	2007
Grand Coulee	GCL G1-9 Unit Transformer Replacement	Stage 4 (Execution)	2008
Grand Coulee	GCL G19-24 Governor Replacement	Stage 4 (Execution)	2008
Grand Coulee	GCL Fixed Wheel Gate Chamber Modification	Stage 4 (Execution)	2009
Grand Coulee	GCL Elevator Rehabilitation	Stage 4 (Execution)	2009
Grand Coulee	GCL TPP Crane Rehabilitation	Stage 4 (Execution)	2009
Grand Coulee	GCL TPP High Voltage Cable Repl.	Stage 4 (Execution)	2009
Grand Coulee	GCL Material Storage Building	Stage 4 (Execution)	2009
Grand Coulee	GCL G19-20 Unit Uprate (winding)	Stage 4 (Execution)	2010
Grand Coulee	GCL Laser Light Show Replacement (Ph 1 & 2)	Stage 4 (Execution)	2011
Grand Coulee	GCL G22-G24 Wear Ring Replacement	Stage 4 (Execution)	2011
Grand Coulee	GCL Powerplant Battery Replacement	Stage 4 (Execution)	2013
Grand Coulee	GCL Warehouse 3 Replacement	Stage 4 (Execution)	2013
Grand Coulee	GCL G11-G18 Transformer Replacement	Stage 4 (Execution)	2013
Grand Coulee	GCL 500 kV Tie to 230 kV Switchyard	Stage 4 (Execution)	2013
Grand Coulee	GCL Station Service Compressed Air System Upgrades	Stage 4 (Execution)	2013
Grand Coulee	GCL G1-G18 Static Exciter Replacement	Stage 4 (Execution)	2014
Grand Coulee	GCL G1-G18 Governor Replacement	Stage 4 (Execution)	2014

Grand Coulee	GCL TPP K21A-K24A Transformer Replacement	Stage 3 (Short Term Planning)	2014
Grand Coulee	GCL RPH Substation Replacement	Stage 3 (Short Term Planning)	2014
Grand Coulee	TPP Station Service Transformers to Auxiliaries	Stage 3 (Short Term Planning)	2014
Grand Coulee	GCL G1-G18 Isophase Bus	Stage 3 (Short Term Planning)	2014
Grand Coulee	GCL Powerplant Battery Replacement (Phase 2)	Stage 3 (Short Term Planning)	2015
Grand Coulee	GCL - Switchyard DC Battery Upgrades	Stage 3 (Short Term Planning)	2015
Grand Coulee	GCL RPH Substation ZLRS/UARS Replacement	Stage 3 (Short Term Planning)	2015
Grand Coulee	GCL RPH Motor Control Boards (ZRS, MRS, MARS) Replacen	Stage 3 (Short Term Planning)	2015
Grand Coulee	GCL G1-G18 Governor Replacement (Phase II)	Stage 3 (Short Term Planning)	2016
Grand Coulee	GCL TPP K21A-K24A Transformer Replacement (Phase II)	Stage 3 (Short Term Planning)	2016
Grand Coulee	GCL G1-G18 Static Exciter Replacement (Phase II)	Stage 3 (Short Term Planning)	2016
Grand Coulee	GCL 11.95 kV Switchgear Replacement (Local Service)	Stage 3 (Short Term Planning)	2017
Grand Coulee	GCL TPP KX26a Transformer Bank (3@400MVA)	Stage 2 (Long Term Planning)	2013
Grand Coulee	GCL - TPP Turbine Overhauls (AA adjustment)	Stage 2 (Long Term Planning)	2015
Grand Coulee	GCL Industrial Area Crane Controls	Stage 2 (Long Term Planning)	2016
Grand Coulee	GCL G19-21 Winding Replacements	Stage 2 (Long Term Planning)	2016
Grand Coulee	GCL TPP 125 VDC Battery Distribution Boards (BS3B/BS3E) I	Stage 2 (Long Term Planning)	2016
Grand Coulee	GCL Dam Station Service Switchgear and Cable Replaceme	Stage 2 (Long Term Planning)	2017
Grand Coulee	GCL - Replace SS Transformers KALS and KBLS	Stage 2 (Long Term Planning)	2017
Grand Coulee	GCL 230 kV Switchyard Breaker Replacement	Stage 2 (Long Term Planning)	2017
Grand Coulee	GCL Replace TPP SS Xformer D19A, 21A, 23A, DS3A, US3A	Stage 2 (Long Term Planning)	2018
Grand Coulee	GCL New Firehouse	Stage 2 (Long Term Planning)	2018
Grand Coulee	GCL RPH/LPH 48 VDC Battery Chargers (BRA/BRB) Replacer	Stage 2 (Long Term Planning)	2018
Grand Coulee	GCL - LPH/RPH Crane Control Upgrades	Stage 2 (Long Term Planning)	2018
Grand Coulee	GCL - Powerhouse Switchgear Upgrades	Stage 2 (Long Term Planning)	2018
Grand Coulee	GCL - TPP Governor Pump Motor Control Assembly (M19A-	Stage 2 (Long Term Planning)	2018
Grand Coulee	GCL Replace SS Substation DWA 230 Swyd	Stage 2 (Long Term Planning)	2018
Grand Coulee	GCL Replace SS Substation DNA 115 Swyd	Stage 2 (Long Term Planning)	2019
Grand Coulee	GCL New G1-18 Transformer Disconnects (High Side)	Stage 2 (Long Term Planning)	2019
Grand Coulee	GCL Additional Station Service Feed to RPP/PGP	Stage 2 (Long Term Planning)	2020
Grand Coulee	GCL 500 kV Unit Breakers (D Breaker)	Stage 2 (Long Term Planning)	2020
Green Peter	GPR Repl. (SYS Exciter)	Stage 4 (Execution)	2000
Green Peter	GPR/FOS Generator Fire Protection & HVAC	Stage 4 (Execution)	2005
Green Peter	GPR/FOS Protective Relays Replacement	Stage 4 (Execution)	2009
Green Peter	GPR Digital Governors	Stage 4 (Execution)	2011
Green Peter	GPR Spillway Gate Rehabilitation - 1 gate	Stage 4 (Execution)	2012
Green Peter	GPR Powerhouse and Transformer Oil Water Separator (PI	Stage 4 (Execution)	2012
Green Peter	WVY and LOS GDACS_GPR (Phase 1)	Stage 4 (Execution)	2013
Green Peter	GPR Main Unit Breakers and Electrical Reliability Upgrades	Stage 4 (Execution)	2013
Green Springs	GSP Transformer Repl.	Stage 4 (Execution)	2003
Green Springs	GSP Excitation System Replacement	Stage 4 (Execution)	2012
Hills Creek	HCR Repl. (SYS Exciter)	Stage 4 (Execution)	2000
Hills Creek	HCR Generator Fire Protection & HVAC	Stage 4 (Execution)	2005
Hills Creek	HCR Turbine Runner and Generator Rewind	Stage 4 (Execution)	2006
Hills Creek	HCR Bridge Crane Rehab.	Stage 4 (Execution)	2008
Hills Creek	HCR Protective Relays Replacement	Stage 4 (Execution)	2009
Hills Creek	COU/HCR (HCR Only) Powerhouse and Transformer Oil Wa	Stage 4 (Execution)	2010
Hills Creek	HCR Digital Governor	Stage 4 (Execution)	2011
Hills Creek	WVY and LOS GDACS_HCR (Phase 1)	Stage 4 (Execution)	2014

Capital Program Projects
by Plant, Stage and Start Year

Hungry Horse	HGH CO2 Replacement	Stage 4 (Execution)	1999
Hungry Horse	HGH Fiber	Stage 4 (Execution)	2000
Hungry Horse	HGH SCADA Replacement	Stage 4 (Execution)	2004
Hungry Horse	HGH Roof Replacement	Stage 4 (Execution)	2010
Hungry Horse	HGH Main Transformer Fire Protection System Replaceme	Stage 4 (Execution)	2011
Hungry Horse	HGH SS and MCC Upgrades	Stage 4 (Execution)	2011
Hungry Horse	HGH Static Exciters	Stage 4 (Execution)	2013
Hungry Horse	HGH Powerplant Crane Controls	Stage 4 (Execution)	2013
Hungry Horse	HGH G1-G4 Governor Replacement	Stage 4 (Execution)	2013
Hungry Horse	HGH G1-G4 Governor Replacement (Phase II)	Stage 3 (Short Term Planning)	2015
Hungry Horse	HGH Powerplant Crane Controls (Phase II)	Stage 3 (Short Term Planning)	2015
Hungry Horse	HGH Turbine/Stator/Winding Study and Upgrade	Stage 2 (Long Term Planning)	2017
Ice Harbor	IHR Turbine Runner Design & Repl. Units 1,2,3	Stage 4 (Execution)	2001
Ice Harbor	IHR Emergency Notification (Pagers)	Stage 4 (Execution)	2006
Ice Harbor	IHR Tailrace Crane Rehab	Stage 4 (Execution)	2008
Ice Harbor	IHR T6 Transformer Replacement	Stage 4 (Execution)	2009
Ice Harbor	IHR Potable Water System Repl.	Stage 4 (Execution)	2009
Ice Harbor	IHR Project Storage Building	Stage 4 (Execution)	2010
Ice Harbor	IHR DC System Upgrade (Ph. 1 & 2)	Stage 4 (Execution)	2011
Ice Harbor	IHR Low Voltage Switchgear Upgrades - SQ Boards (Ph. 1 &	Stage 4 (Execution)	2011
Ice Harbor	IHR T1,T2,T3 Cooler Leak Repair (Phases 1 & 2)	Stage 4 (Execution)	2012
Ice Harbor	IHR Main Units 1-6 Digital Governor (Phase 1 & 2)	Stage 4 (Execution)	2012
Ice Harbor	IHR Drainage & De-Watering Pump Upgrade (Phase 1 and F	Stage 4 (Execution)	2012
Ice Harbor	IHR Draft Tube & Scroll Case Access Tugger (Phase 1)	Stage 4 (Execution)	2013
Ice Harbor	IHR XW-5 Breaker Repair (Phase 1 & 2)	Stage 4 (Execution)	2013
Ice Harbor	IHR Draft Tube & Scroll Case Access Tugger (Phase 2)	Stage 3 (Short Term Planning)	2013
Ice Harbor	IHR Upgrade Telephone Switch and System	Stage 3 (Short Term Planning)	2014
Ice Harbor	IHR MU Cooling Water Strainers Replacement	Stage 3 (Short Term Planning)	2014
John Day	JDA Exciter Repl. (SYS Exciter)	Stage 4 (Execution)	2000
John Day	JDA Control Room Fire Protection Upgrades	Stage 4 (Execution)	2006
John Day	JDA Bridge Crane Rehab	Stage 4 (Execution)	2006
John Day	JDA Protective Relays Replacement	Stage 4 (Execution)	2009
John Day	JDA Elevator Rehabilitation (Ph 1 & 2)	Stage 4 (Execution)	2010
John Day	JDA Fish Hydro Pump Rehabilitation	Stage 4 (Execution)	2011
John Day	JDA Powerhouse Unit 11 Repair	Stage 4 (Execution)	2011
John Day	JDA Digital Governors	Stage 4 (Execution)	2011
John Day	JDA DC System Upgrades (Ph 1)	Stage 4 (Execution)	2012
John Day	JDA Draft Tube Bulkheads and Intake Gates(Ph. 1)	Stage 4 (Execution)	2013
John Day	JDA BLH Turbine Hub Upgrades and Fixed Blade Conversio	Stage 4 (Execution)	2013
John Day	JDA BLH Hub Upgrade Kits	Stage 4 (Execution)	2013
John Day	JDA Oil Replacement	Stage 4 (Execution)	2013
John Day	JDA SS Transformer Replacements (Phase 1)	Stage 4 (Execution)	2013
John Day	JDA BLH Turbine Hub Upgrades and Fixed Blade Conversio	Stage 4 (Execution)	2014
John Day	JDA Powerhouse Unit 5 Blocking and Ph 1 Repair	Stage 3 (Short Term Planning)	2013
John Day	JDA DC System Upgrades (Ph 2)	Stage 3 (Short Term Planning)	2014
John Day	JDA Draft Tube Bulkheads and Intake Gates (Ph. 2)	Stage 3 (Short Term Planning)	2014
John Keys PGP	GCL PG Transformer Repl. & Circuit Addition	Stage 4 (Execution)	2000
John Keys PGP	GCL PG Plant Modernization and Upgrades	Stage 4 (Execution)	2010
John Keys PGP	GCL KP10B Transformer Replacement (Phase 1)	Stage 4 (Execution)	2012

John Keys PGP	GCL P5 and P6 Impellers, Stators and Core Rewinds Ph1	Stage 4 (Execution)	2012
John Keys PGP	GCL P5 and P6 Impellers, Stators and Core Rewinds Ph 2	Stage 3 (Short Term Planning)	2013
John Keys PGP	GCL KP10B Transformer Replacement (Phase 2)	Stage 3 (Short Term Planning)	2013
Libby	LIB System Reliability	Stage 4 (Execution)	1997
Libby	LIB Powerhouse Cranes	Stage 4 (Execution)	1999
Libby	LIB Transformer Refurbishment (SYS)	Stage 4 (Execution)	2001
Libby	LIB MUB (SYS Main Unit Breakers)	Stage 4 (Execution)	2003
Libby	LIB Spare Transformer	Stage 4 (Execution)	2004
Libby	LIB GDACS and Spillway	Stage 4 (Execution)	2004
Libby	LIB Exciter Replacement	Stage 4 (Execution)	2004
Libby	NWS Remoting (LIB)	Stage 4 (Execution)	2005
Libby	LIB Governor (SYS Governor Repl.)	Stage 4 (Execution)	2007
Libby	LIB HVAC Controls and Rehab.	Stage 4 (Execution)	2008
Libby	LIB Selective Withdrawal Crane (Ph 1&2)	Stage 4 (Execution)	2009
Libby	LIB Powerhouse Elevators Rehab. (Ph 1&2)	Stage 4 (Execution)	2009
Libby	LIB Monolith 28 Elevator Rehab. (Ph 1&2)	Stage 4 (Execution)	2009
Libby	LIB Powerhouse Electrical Distribution Equipment Replace	Stage 4 (Execution)	2013
Libby	LIB Dam Electrical Distribution Equipment	Stage 4 (Execution)	2013
Libby	LIB System Control Console - Plant (SCC)	Stage 3 (Short Term Planning)	2014
Libby	LIB Water Mist - Oil Room	Stage 3 (Short Term Planning)	2014
Libby	LIB Powerhouse DC Emergency Lighting System	Stage 3 (Short Term Planning)	2014
Libby	LIB Powerhouse Roof Replacement	Stage 3 (Short Term Planning)	2014
Libby	LIB Vibration Monitoring System	Stage 2 (Long Term Planning)	2015
Libby	LIB DC Boards & Bkrs Sys 1 & 2	Stage 2 (Long Term Planning)	2015
Libby	LIB Additional Station Service TAP	Stage 2 (Long Term Planning)	2018
Little Goose	LGS Emergency Notification (Pagers)	Stage 4 (Execution)	2006
Little Goose	LGS Diesel Generator	Stage 4 (Execution)	2007
Little Goose	LGS 1-6 Exciter Replacement	Stage 4 (Execution)	2009
Little Goose	LGS Powerhouse HVAC Control Upgrade	Stage 4 (Execution)	2009
Little Goose	LGS Wastewater Treatment Plant (Ph. 1)	Stage 4 (Execution)	2010
Little Goose	LGS Intake Crane Replacement (Ph1 & Ph 2)	Stage 4 (Execution)	2011
Little Goose	LGS Standby Thrust Bearing Shoes, Thurst Runner & Oil Ass	Stage 4 (Execution)	2011
Little Goose	LGS Powerhouse Bridge Crane Rehab (Phase 1 and 2)	Stage 4 (Execution)	2011
Little Goose	LGS Digital Govenors Upgrade (Phases 1 & 2)	Stage 4 (Execution)	2013
Little Goose	LGS Upgrade Telephone Switch and System	Stage 3 (Short Term Planning)	2014
Little Goose	LGS Iso Phase Bus & Housing Mod (Phase 1)	Stage 3 (Short Term Planning)	2014
Little Goose	LGS Upgrade Telephone Switch and System (Ph 2B)	Stage 3 (Short Term Planning)	2015
Little Goose	LGS DC System Upgrade (Phase 1)	Stage 2 (Long Term Planning)	2015
Little Goose	LGS Tailrace Gantry Crane Replacement	Stage 2 (Long Term Planning)	2015
Lookout Point	LOP Generator Fire Protection & HVAC	Stage 4 (Execution)	2005
Lookout Point	LOP Cranes (was WVL assessment)	Stage 4 (Execution)	2005
Lookout Point	LOP Turbine Runner Replacement (Ph. 1&2)	Stage 4 (Execution)	2005
Lookout Point	LOP Penstock Roller Gates	Stage 4 (Execution)	2008
Lookout Point	LOP/DEX Protective Relays Replacement	Stage 4 (Execution)	2009
Lookout Point	LOP Emergency Engine Generator (Phase 1& 2)	Stage 4 (Execution)	2011
Lookout Point	LOP Powerhouse and Transformer Oil Water Separator (Ph	Stage 4 (Execution)	2012
Lookout Point	LOP Digital Governors	Stage 4 (Execution)	2013
Lookout Point	LOP Spillway Gate Rehabilitation -- 2 gates plus	Stage 4 (Execution)	2013
Lookout Point	WVY and LOS GDACS_LOP (Phase 1)	Stage 4 (Execution)	2014

Capital Program Projects
by Plant, Stage and Start Year

Lookout Point	LOP Spillway Gate Rehabilitatioin -- 2 plus gates - Ph2	Stage 3 (Short Term Planning)	2014
Lost Creek	LOS Fire Protection (Ph. 1)	Stage 4 (Execution)	2009
Lost Creek	LOS Digital Governors	Stage 4 (Execution)	2011
Lost Creek	LOS Butterfly Valves Replacement (Ph 1)	Stage 4 (Execution)	2013
Lost Creek	LOS Wicket Gate Seals Redesign/Upgrade Ph 1	Stage 4 (Execution)	2013
Lost Creek	WVY and LOS GDACS_LOS (Phase 1)	Stage 4 (Execution)	2014
Lost Creek	LOS Wicket Gate Seals Redsign/Upgrade - Ph 2	Stage 3 (Short Term Planning)	2014
Lost Creek	LOS Butterfly Vales Replacement - Ph 2	Stage 3 (Short Term Planning)	2014
Lower Granite	LGR Replacement Windings 1-3 (SYS Gen)	Stage 4 (Execution)	2001
Lower Granite	LGR -- SNK Spare Winding for units 4-6 (SYS Gen)	Stage 4 (Execution)	2002
Lower Granite	LGR Rotor Pole Refurbishment (SYS Gen)	Stage 4 (Execution)	2004
Lower Granite	LGR Governor (SYS Governor Repl.)	Stage 4 (Execution)	2004
Lower Granite	LGR Emergency Notification (Pagers)	Stage 4 (Execution)	2006
Lower Granite	LGR Intake Crane Replacement	Stage 4 (Execution)	2006
Lower Granite	LWG Diesel Generator	Stage 4 (Execution)	2007
Lower Granite	LGR Elevator Rehab.-CNO&NNO	Stage 4 (Execution)	2009
Lower Granite	LWG 4-6 Exciter Replacement	Stage 4 (Execution)	2009
Lower Granite	LGR SQ2 Replacement	Stage 4 (Execution)	2009
Lower Granite	LGR Spillway Emerg. Diesel Gen. Transfer Switch	Stage 4 (Execution)	2010
Lower Granite	LWG 8th FL. Office Expansion (Phase 1)	Stage 4 (Execution)	2011
Lower Granite	LWG Sewage Treatment Plant Upgrade (Phase 1)	Stage 4 (Execution)	2011
Lower Granite	LWG Powerhouse Bridge Crane Rehab (Phase 1 and 2)	Stage 4 (Execution)	2011
Lower Granite	LWG Powerhouse HVAC Upgrade (Phase 1)	Stage 4 (Execution)	2012
Lower Granite	LWG Powerhouse Roof Repair (Phase 1 & 2)	Stage 4 (Execution)	2013
Lower Granite	LWG Digital Governor Upgrade (Phases 1 & 2)	Stage 4 (Execution)	2013
Lower Granite	LWG Upgrade Telephone Switch and System (Ph 2B)	Stage 3 (Short Term Planning)	2014
Lower Granite	LWG Upgrade Telephone Switch and System	Stage 3 (Short Term Planning)	2014
Lower Granite	LWG ZJ6 Breakers	Stage 2 (Long Term Planning)	2017
Lower Granite	LWG Wicket Gate Gatelocks U4-U6	Stage 2 (Long Term Planning)	2021
Lower Monumenta	LMN Exciters 1-3	Stage 4 (Execution)	2002
Lower Monumenta	LMN Intake Crane Rehab.	Stage 4 (Execution)	2005
Lower Monumenta	LMN Emergency Notification (Pagers)	Stage 4 (Execution)	2006
Lower Monumenta	LMN Diesel Generator	Stage 4 (Execution)	2007
Lower Monumenta	LMN Bridge Crane	Stage 4 (Execution)	2008
Lower Monumenta	LMN U1 Refurb, U1 and U2 Cavitation Work (Ph. 1)	Stage 4 (Execution)	2009
Lower Monumenta	LMN SQ2 Replacement	Stage 4 (Execution)	2009
Lower Monumenta	LMN 4-6 Exciter Replacement	Stage 4 (Execution)	2009
Lower Monumenta	LMN U1 Refurb, U1 and U2 Cavitation Work (Ph. 2)	Stage 4 (Execution)	2013
Lower Monumenta	LMN Bridge Crane Drive Upgrades	Stage 4 (Execution)	2013
Lower Monumenta	LMN Digital Governor Upgrade (Phases 1 & 2)	Stage 4 (Execution)	2013
Lower Monumenta	LMN Upgrade Telephone Switch and System	Stage 3 (Short Term Planning)	2014
Lower Monumenta	LMN Upgrade Telephone Switch and System (Ph 2B)	Stage 3 (Short Term Planning)	2015
McNary	MCN Turbine Runner Replacement	Stage 4 (Execution)	2002
McNary	MCN Turbine Runner Accessories	Stage 4 (Execution)	2002
McNary	MCN Reliability Improvement (except turbine)	Stage 4 (Execution)	2002
McNary	MCN Governor (SYS Governor Repl.)	Stage 4 (Execution)	2002
McNary	MCN Roof Replacement	Stage 4 (Execution)	2006
McNary	MCN Fire Protection	Stage 4 (Execution)	2006
McNary	MCN Generator Rewinds	Stage 4 (Execution)	2008

McNary	MCN Transformer Purchase	Stage 4 (Execution)	2008
McNary	MCN T1, T2, T4 & T5 Transformer Install	Stage 4 (Execution)	2008
McNary	MCN Protective Relays (Ph. 1 & 2)	Stage 4 (Execution)	2009
McNary	MCN 4160-480V Station Service Replacement	Stage 4 (Execution)	2010
McNary	MCN Turbine Design and Replacement (Phase 1)	Stage 4 (Execution)	2011
McNary	MCN Potable Water System Upgrade (Ph. 1)	Stage 4 (Execution)	2011
McNary	MCN WAFL Entrance Logs (Phase 1)	Stage 4 (Execution)	2011
McNary	MCN Fishway Exit Crane 9 and 10 Replacement (Ph. 1 & 2)	Stage 4 (Execution)	2011
McNary	MCN PH Heat Pump & Control Replacement (Ph. 1 and 2)	Stage 4 (Execution)	2011
McNary	MCN Levee Drainage Pump Station Upgrades (Ph. 1)	Stage 4 (Execution)	2011
McNary	MCN Bridge Crane Fall Protection System	Stage 4 (Execution)	2012
McNary	MCN Digital Governors U1-14 (Phase 1 & 2)	Stage 4 (Execution)	2013
McNary	MCN 4160-480V Station Service Repl (Ph. 2B)	Stage 4 (Execution)	2014
McNary	MCN WAFL Entrance Logs Phase 2	Stage 3 (Short Term Planning)	2014
McNary	MCN Fourth Spare Tailrace Bulkheads	Stage 3 (Short Term Planning)	2014
McNary	MCN Project Storage Building	Stage 3 (Short Term Planning)	2014
McNary	MCN Upgrade Telephone Switch and System	Stage 3 (Short Term Planning)	2014
McNary	MCN Exciters Upgrade (Phase 1)	Stage 3 (Short Term Planning)	2014
McNary	MCN Upgrade Telephone Switch and System (Ph 2B)	Stage 3 (Short Term Planning)	2015
McNary	MCN Turbine Design and Replacement (Phase 2)	Stage 3 (Short Term Planning)	2016
McNary	MCN Iso-Phase Bus Upgrade (Phase 1)	Stage 2 (Long Term Planning)	2019
Minidoka	MIN/PAL Modifications	Stage 4 (Execution)	2000
Minidoka	MIN Microwave System Backbone East Side	Stage 4 (Execution)	2014
Palisades	PAL Powerplant Fire Detection and Alarm System	Stage 4 (Execution)	2012
Palisades	PAL Microwave System Backbone East Side	Stage 4 (Execution)	2014
Roza	ROZ Exciter Repl.	Stage 4 (Execution)	2007
Roza	ROZ Switch Rehab and Breaker Upgrade	Stage 4 (Execution)	2014
The Dalles	TDA Governor (SYS Governor Repl.)	Stage 4 (Execution)	2001
The Dalles	TDA Oil/Water Separator (SYS)	Stage 4 (Execution)	2003
The Dalles	TDA Synchr. Cond. Upgrade (funded by TBL)	Stage 4 (Execution)	2004
The Dalles	TDA Station Service Improvement	Stage 4 (Execution)	2004
The Dalles	TDA Spare 230 KV Transformer Repl.	Stage 4 (Execution)	2005
The Dalles	TDA Control Room Fire Detection Upgrades	Stage 4 (Execution)	2005
The Dalles	TDA Spillway Repair	Stage 4 (Execution)	2006
The Dalles	TDA Heat Pump #3 & Coil Replacement	Stage 4 (Execution)	2006
The Dalles	TDA Powerhouse Roof Replacement	Stage 4 (Execution)	2010
The Dalles	TDA Elevator Rehabilitation (Ph 1 & 2)	Stage 4 (Execution)	2010
The Dalles	TDA DC System Upgrades	Stage 4 (Execution)	2011
The Dalles	TDA SCC Control Replacement (Ph. 1)	Stage 4 (Execution)	2012
The Dalles	TDA Tailrace Gantry Crane (Ph 1)	Stage 4 (Execution)	2012
The Dalles	TDA Preferred AC System Upgrades	Stage 4 (Execution)	2013
The Dalles	TDA Transformer Replacement T1,3,5,6,7,8 (Phase 1)	Stage 4 (Execution)	2013
The Dalles	TDA Turbine Model ERDC	Stage 3 (Short Term Planning)	2013
The Dalles	TDA Tailrace Gantry Crane (Ph 2)	Stage 3 (Short Term Planning)	2014
The Dalles	TDA SCC Control Replacement (Ph. 2)	Stage 3 (Short Term Planning)	2014

Appendix B

Optimum Timing for Equipment Replacement

Least Cost Planning

The strategy takes a least-cost approach to determining the timing of future equipment replacement decisions. The approach is consistent with the Regional Power Act, BPA's asset management policy, and BPA's Climate Change Action Plan.

Costs Evaluated in the Strategy

Equipment Replacement Cost – Forecasted replacement costs were developed for 50 equipment types (turbine runner, transformer, etc.) by the Corps' Hydroelectric Design Center, the organization responsible for developing government estimates for procurement of Corps hydroelectric equipment. For each equipment type, cost estimates include a fixed cost component, which is the same for all equipment of that type, and a variable cost component, which is dependent on parameters related to the size and complexity of the equipment, i.e., shaft diameter, MVa rating, etc.

Incremental Equipment Failure Cost – When equipment fails, costs to repair or replace it are typically incrementally higher due to collateral damage and to planning, procurement and scheduling inefficiencies. Incremental failure costs are specific to each equipment type, expressed as a percentage of replacement cost when done on a planned basis.

Replacement Power Cost – For the asset strategy, Federal Hydro Projects used hydro regulation studies to determine the amount of generation produced by each plant on the system assuming each generating unit is available 90 percent of the time (somewhat high for the FCRPS based on recent history, but in line with industry averages and a reasonable steady-state level for a reliable plant). Generation amounts were calculated for HLH and LLH periods by month for 50 water years. Next, hydro regulation studies were run at lower levels of unit availability to determine the amount of generation that would be produced if the plants were less reliable. The difference between modeling runs produces the incremental generation from an increment of plant availability. For the strategy, the incremental generation produced by the "least used" unit (marginal unit) was calculated for each plant on the system. This is the amount of generation that is deemed to be at risk in the event of equipment failure. Although a distinct possibility, particularly for plants with many generating units or low reliability, no consideration was given to multiple and simultaneous equipment failures that would take more than one unit out of service and have increasingly higher lost generation consequences.

When equipment fails and takes a generating unit out of service, repairing and replacing the equipment typically takes longer than if work is done on a proactive, planned basis. For instance, a transformer can take three or more years to procure and, absent having a spare available, a failure would take a generating unit (or multiple units) out of service for

Costs Evaluated in the Strategy

three years or longer. Replacing a transformer on a planned basis typically requires an outage of three months or less. So, the incremental outage duration for a failed transformer can be 2.75 years if no spare is available (we assumed 1.5 years in the strategy). Other equipment types have much shorter incremental outage durations.

The annual generation at risk for the marginal unit at each plant is then multiplied by the expected additional outage in years for each equipment type to determine the amount of lost generation if that equipment fails. The lost generation is valued at BPA's rate case long-term forward price forecast to determine a replacement power cost (or lost secondary market opportunity) for the equipment failure.

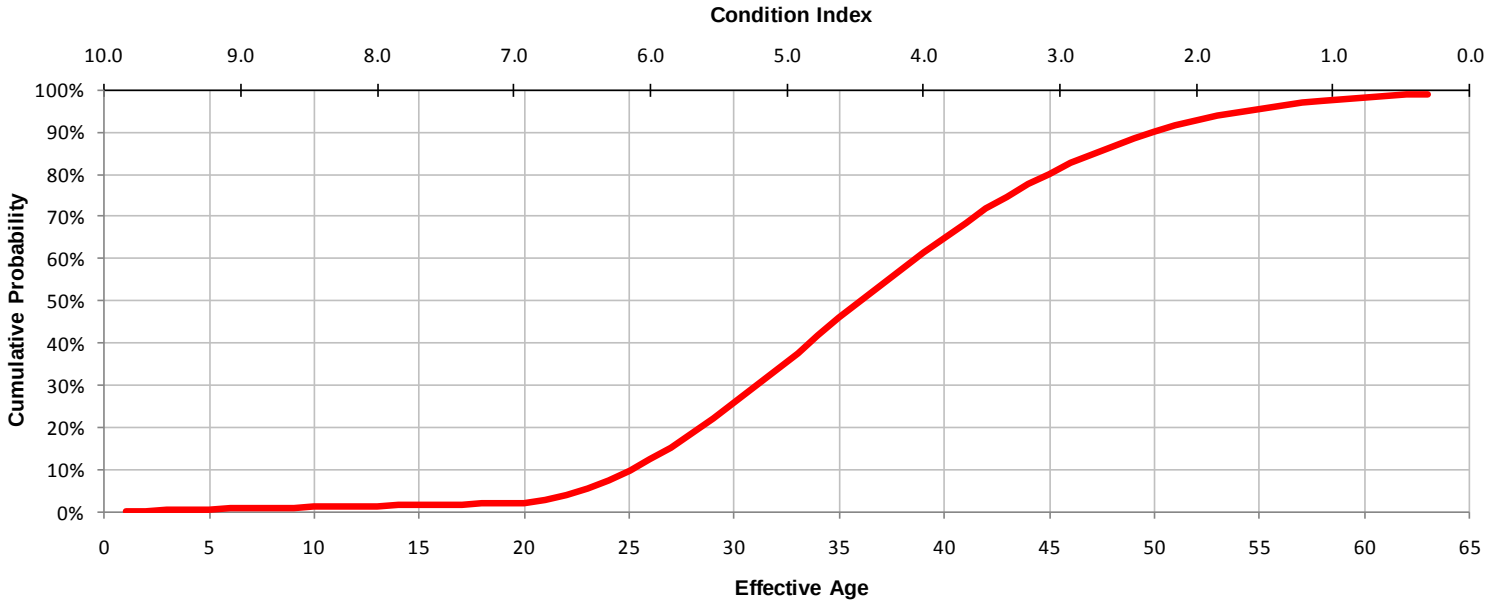
CO2 Cost – BPA's Climate Change Action Plan requires hydro investment decisions to include greenhouse gas avoidance benefits in asset planning analyses and business cases for proposed capital and major expense sub-agreements. Guidance from BPA Corporate Strategy is to use CO2 costs from the Power Council's 6th Power Plan for determining that value. The plan's 20-year levelized cost of CO2 emissions is $35 per ton (2012 dollars). This cost is multiplied by the CO2 emissions generated by a combined cycle natural gas plant (0.48 tons per MWh) – the resource that would be used to offset losses in hydro generation – to determined the avoided CO2 cost for maintaining hydro plant reliability.

For the strategy analysis, only equipment replacement costs are deterministic. Other costs are probability-based, derived from information about equipment condition that is correlated to a likelihood of failure.

Equipment Condition and its Relationship to Risk

The strategy analysis uses hydroAMP to assess condition of power train and some other hydro equipment. Developed by the Corps, Reclamation, BPA and Hydro Quebec, hydroAMP uses a set of condition indicators describing operational performance, maintenance history, physical inspection, age, and specialized testing results to derive a condition index for equipment. The condition index scale ranges from zero (Poor condition) to 10 (Good condition). For equipment not covered by hydroAMP, a simplified condition assessment tool was built based on the hydroAMP methodology.

A regression analysis was performed on the hydroAMP database to establish a correlation between a condition index and equipment "effective age". The results were then used to map the hydroAMP condition index and effective age to a survivor curve for that equipment. Survivor curves are derived from industry data and show the relationship between equipment age and the percentage of the equipment population that has failed or been retired. Mapping the hydroAMP results to the survivor curve yields a failure probability for equipment with a certain condition index and effective age.



Equipment Condition and its Relationship to Risk

Risk is a function of the probability of failure as condition degrades over time. For the strategy, four types of risk were calculated in incremental time steps:

Safety Risk, where equipment failure has a relatively high probability of causing permanent disabilities or multiple fatalities;

Environmental Risk, where equipment failure has a relatively high probability of causing detrimental or catastrophic environmental impacts;

Direct Cost Risk, which is the Incremental Equipment Failure Cost identified above multiplied by the incremental probability of failure over time; and,

Lost Generation Risk, which is the sum of Replacement Power Cost and CO2 Cost multiplied by the incremental probability of failure.

The sum of Direct Cost Risk and Lost Generation Risk are hereafter described as financial risk.

Optimum Timing for Equipment Replacement

To determine the optimum timing for replacement, each equipment component is evaluated in yearly time steps over 20 years. In each year, the present value of accumulated financial risk cost is added to the present value cost of replacing the equipment in that year. The sum of these present value costs is the Total Cost related to a decision to delay equipment replacement until that year. This algorithm is described graphically on the next page.

Total Cost of Replacement at Different Points in Time

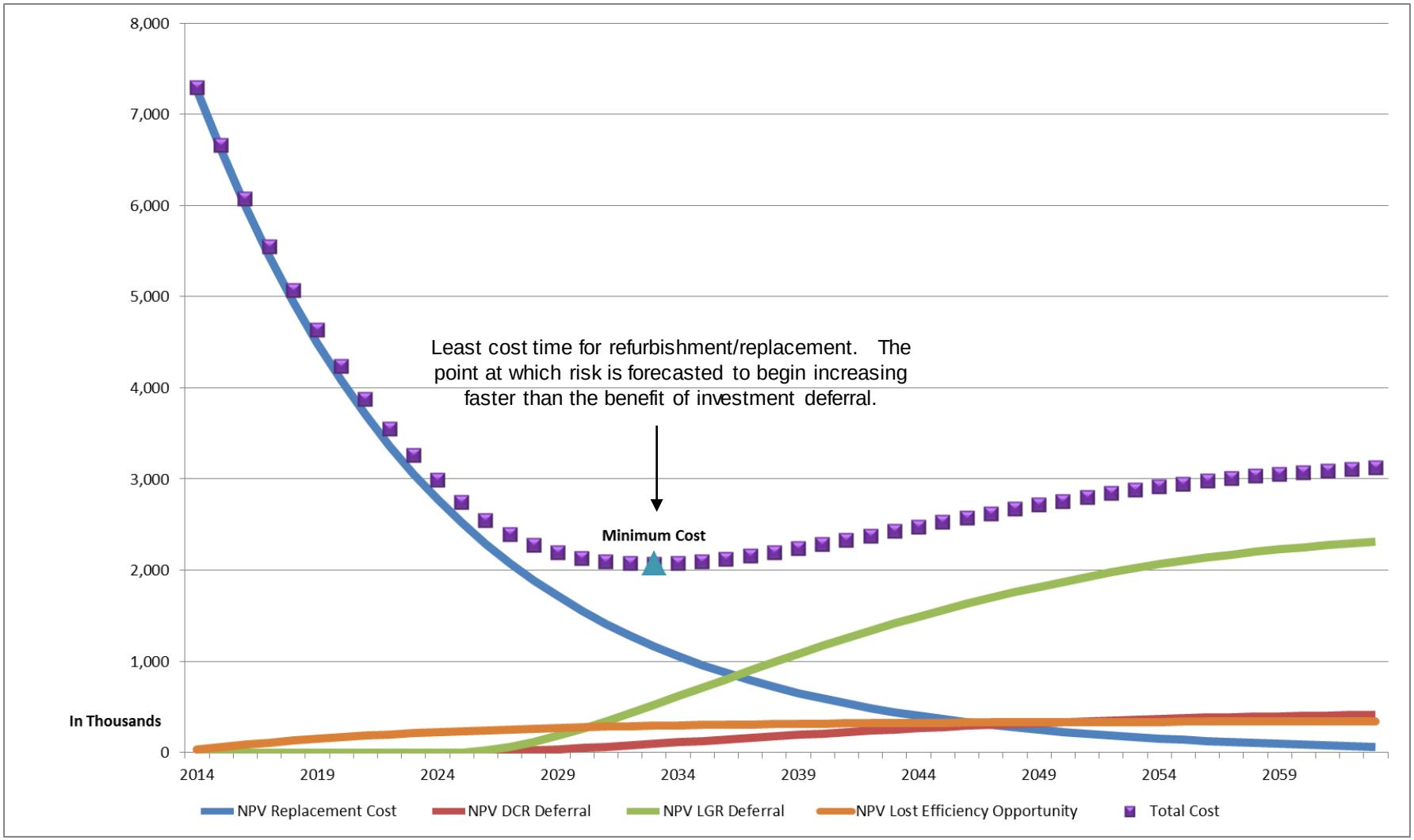
The optimum time to plan on equipment replacement is at the low point (cost minimum) of the Total Cost curve. The cost minimum is the point in time at which financial risk costs begin growing faster than the benefit of deferring the investment. Up until that time the value of investment deferral is greater than the expected increase in financial risk costs, so it makes financial sense to continue deferring equipment replacement. This objective function is applied to each of the 5,500 equipment components included in the strategy to derive an investment plan.

Running the model without funding constraints generates the “least-cost case”. Under this scenario, equipment replacements for projects that are already underway are funded as planned. Potential new investments are then selected for refurbishment/replacement if they meet either of the following criteria:

- First, if condition places the equipment into a safety or environmental high risk category; or,
- Secondly, if financial risk costs are increasing faster than the investment deferral benefit, i.e., the equipment has reached the cost minimum.

The model can also be run to limit annual funding availability to any level desired. For these cases, once an annual funding limitation is reached, investment in equipment in which financial risk is increasing the least is deferred until the following year, where it is then re-evaluated using the same prioritization logic. As funding levels are increasingly constrained, more new investments are deferred past their cost minimum which causes the Total Cost to increase accordingly.

Optimum Timing for Equipment Replacement

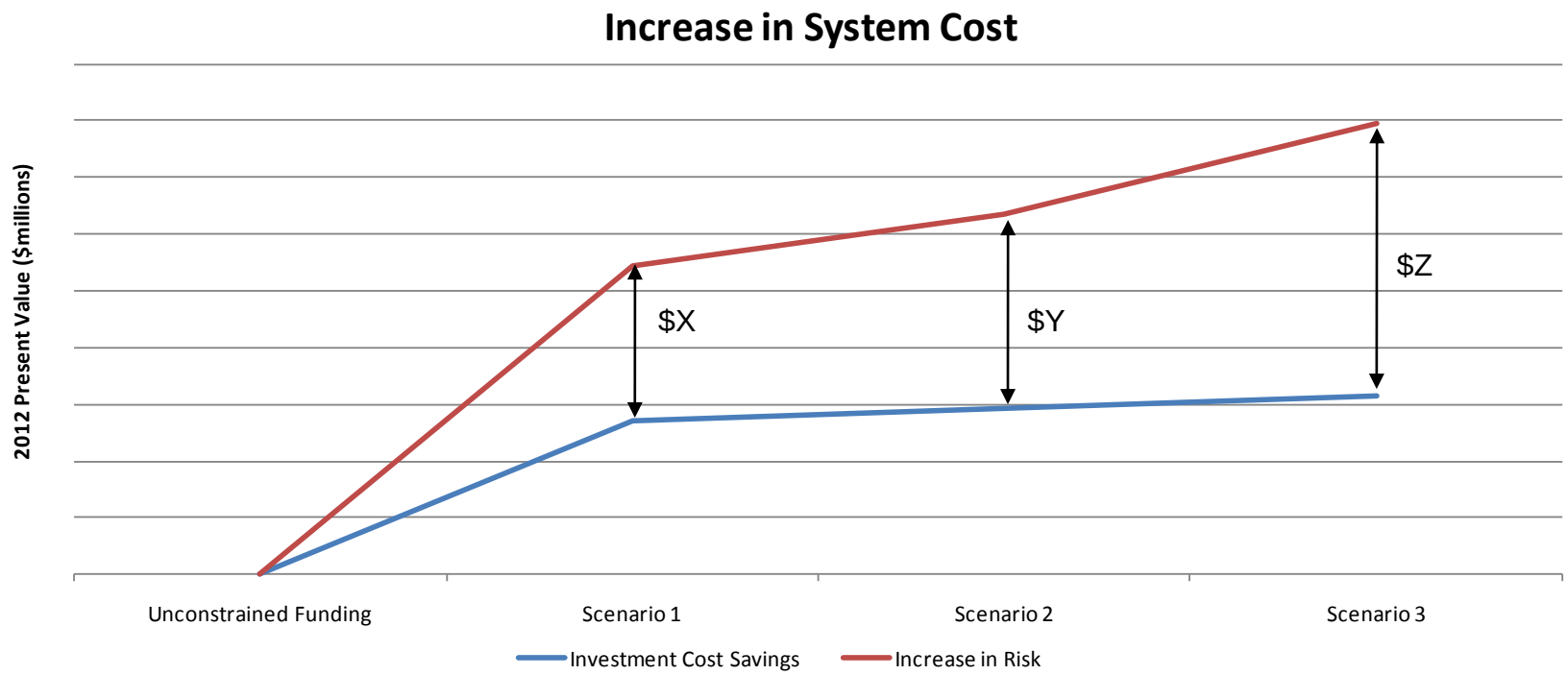


Net Present Value

Calculation of Net Present Value

The Total Cost for the system increases when a funding constraint causes new investments to be pushed out past the cost minima. The present value of investment costs is reduced, but risk increases by a larger amount. The Total Cost difference between various funding availability scenarios and an unconstrained funding alternative yields the increase in system cost.

The net present value of each scenario is the negative of the increase in system cost, i.e., the Total Cost of unconstrained funding minus the Total Cost of a constrained funding scenario.



End

Capital Investment Review

Financial Disclosure

This information has been made publicly available by BPA on February 18, 2014 and contains information not reported in agency financial statements.