RECLAMATION

Managing Water in the West

Hydropower Modernization Initiative

Assessment of Potential Capacity Increases at Existing Hydropower Plants

U.S. Department of the Interior
Bureau of Reclamation
Sacramento, California

MWH
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FINAL - October 2010

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The mission of the Bureau of Reclamation is to manage, develop, and protect water and related resources in an environmentally and economically sound manner in the interest of the American public.

Assessment of Potential Capacity Increases at Existing Hydropower Plants

Hydropower Modernization Initiative

Prepared for

United States Department of the Interior
Bureau of Reclamation

Prepared by

MWH

BUILDING A BETTER WORLD

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF RECLAMATION

U.S. Department of the Interior
Bureau of Reclamation
Denver, Colorado

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October 26, 2010

U.S. Bureau of Reclamation
Denver Federal Center
Bldg. 67 (86-61600)
P.O. Box 25007
Denver, CO 80225-0007

Attn: Mr. Michael Pulskamp

Subject: Final Report on Assessment of Capacity Increases at Existing Hydroelectric Plants

Ref: USACE Contract No. W9127N-10-D-0004, MWH Americas, Inc., Task Order 0002

Dear Michael,

Enclosed is our final report assessing capacity gains at existing United States Bureau of Reclamation (Reclamation) hydroelectric plants. This work was performed under Task 2 of our IDIQ contract with the US Army Corps of Engineers (USACE) for the Hydropower Modernization Initiative, Bureau of Reclamation.

The report presents the results from creating energy simulation models at Reclamation hydropower plants, and developing a comprehensive valuation of benefits from potential capacity increases at all plants. The primary authors of the report were John Haapala and Jill Gray.

MWH appreciates the opportunity to work with Reclamation on this interesting assignment. We hope this document provides useful results regarding potential capacity additions and will help direct future investigation efforts toward the plants that have the most potential. We enjoyed our collaboration with both Reclamation and USACE on this study and look forward to additional opportunities to be of service

Thank you.

John Haapala (for)

Nancy Walker
Project Manager
MWH Americas, Inc.

encl: Final Report

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Executive Summary

There has recently been a considerable resurgence of interest in hydropower in the USA. The current interest in hydropower has been primarily directed at developing incremental hydropower where an existing dam, or an existing dam and powerhouse can be utilized. Incremental hydropower can be developed through efficiency increases in existing units and/or by the addition of capacity to utilize flow for generation that would be otherwise spilled at existing dams. One of the driving forces behind the increased interest in electricity generation from hydropower plants is that greenhouse gas (GHG) emissions from hydropower are virtually zero when compared to thermal generation from fossil fuels. Additional clean hydropower generation would offset or reduce GHG emissions from fossil fuel-fired generation.

Reclamation has 58 existing hydroelectric plants with a total installed capacity of about 15,000,000 kilowatts (kW) (15,000 megawatts [MW]). This report assesses the potential for capacity increases at the 58 existing hydroelectric plants that could potentially generate additional power. Also included in the report is an estimated quantification of incremental energy increases from efficiency gains that would result from replacement of older turbine runners with new runners of modern design. A final task involves the estimation of potential GHG offsets that could be credited to the incremental energy increases or the avoidance of outages at the existing plants.

Due to the large number of plants involved, these studies were performed at the planning-level (reconnaissance-level)) for purposes of screening between plants. Additional more detailed feasibility-level studies of individual plants would be needed to make final investment decisions at those specific plants that show promise for capacity additions in this study.

Because the “best” capacity addition from an economic standpoint was not known in advance, five capacity additions of different sizes were tested for each plant. The capacity additions tested at each plant were 10%, 20%, 30%, 40%, and 50% of the existing combined nameplate capacities (the installed capacity). For each of the alternative capacity additions, a benefit to cost ratio (BCR) and a net present value (NPV) were determined. The preferred capacity addition would have either the maximum benefit to cost ratio (if it was greater than 1.00) or the maximum net present value (if positive).

The determination of benefits from a capacity addition requires the estimation of the average incremental energy generation, which is developed with a hydroelectric energy simulation model. An energy model was developed that could simulate up to 30 years of daily energy generation at each of the 58 existing plants. Plant specific input data to the energy model was supplied by Reclamation that included reservoir outflows and elevations, and many characteristics of the existing hydroelectric plants. Results generally showed reasonable agreement between the simulated and recorded generation, which satisfactorily validates the model.

In addition to the energy generation in megawatt-hours (MWh), the value of energy ($/MWh) and capacity ($/kW-yr) must be known to determine the total benefits of a capacity addition. The value of energy was developed on a regional basis for each of the plants based on information obtained from the Energy Information Administration, Department of Energy. The value of energy was separated into on-peak and off-peak hours. The value of capacity was also developed based on information obtained from the Energy Information Administration, Department of Energy and is a variable function of the relative amount of energy associated with each capacity addition, so the more incremental energy, the higher the capacity value.

An estimate of the costs associated with each plant capacity addition was necessary to evaluate the benefit to cost ratios and net present values. The cost estimates included construction, mitigation, and operation and maintenance costs. The cost estimating methodology was taken from a 2007 Federal report (U.S. Department of the Interior, et al, 2007), known as the 1834 study, on potential hydroelectric development at existing Federal facilities. Notably, the 1834 study excluded the 58 existing Reclamation plants that are studied herein because it was thought at that time that with few exceptions, the existing plants were either originally constructed or had already been uprated so that they were then currently sized to the available flow.

Results of this study show that only 10 of the 58 plants have potential capacity additions of any size with positive NPVs, which corresponds to a BCR greater than 1.00 and is an indicator of economic feasibility. The 10 plants that show initial promise for capacity additions (Table ES-1) are mostly among the smallest of the 58 plants. Selecting the capacity addition at each of the 10 plants that has the highest benefit to cost ratio would result in a total capacity addition of about 67 MW. The additional 67 MW capacity would represent less than one-half of one percent of the existing total nameplate capacity of the 58 plants. If maximum NPV was the criterion for selecting the capacity addition (Table ES-2), the economic capacity addition would rise to about 143 MW, still less than one percent of the existing total nameplate capacity. The Palisades hydropower plant has the highest net present value.

Table ES-1. Capacity Opportunities – Ranked by Benefit to Cost Ratio

Rank [1]	Plant	Region	Existing Installed Capacity (MW)	Maximum BCR Percent Increase	Maximum NPV Percent Increase	Maximum BCR Capacity Increase (MW)	Maximum BCR	Maximum NPV ($M)
1	Shoshone	Great Plains	3.0	50%	50%	1.5	3.50	$12.2
2	Black Canyon	Pacific Northwest	10	50%	50%	5.1	2.52	$19.6
3	Boise Diversion	Pacific Northwest	3.5	40%	50%	1.4	2.48	$7.8
4	Palisades	Pacific Northwest	177	20%	50%	35	2.28	$123
5	Canyon Ferry	Great Plains	50	10%	40%	5.0	1.53	$13.4
6	Guernsey	Great Plains	6.4	50%	50%	3.2	1.52	$4.6
7	Nimbus	Mid-Pacific	13.5	20%	50%	2.7	1.39	$5.8
8	Minidoka	Pacific Northwest	28	10%	20%	2.8	1.21	$2.6
9	Deer Creek	Upper Colorado	5.0	10%	20%	0.5	1.04	$0.1
10	Crystal	Upper Colorado	31.5	30%	30%	9.5	1.00	$0.1

Notes

[1] Plants are ranked based on the capacity addition increment with the highest BCR for each plant .

BCR - Benefit to Cost Ratio

NPV - Net Present Value

Table ES-2. Capacity Opportunities – Ranked by Net Present Value

Rank [1]	Plant	Region	Existing Installed Capacity (MW)	Maximum BCR Percent Increase	Maximum NPV Percent Increase	Maximum NPV Capacity Increase (MW)	Maximum BCR	Maximum NPV ($M)
1	Palisades	Pacific Northwest	177	20%	50%	88	2.28	$123
2	Black Canyon	Pacific Northwest	10	50%	50%	5.1	2.52	$19.6
3	Canyon Ferry	Great Plains	50	10%	40%	20	1.53	$13.4
4	Shoshone	Great Plains	3.0	50%	50%	1.5	3.50	$12.2
5	Boise Diversion	Pacific Northwest	3.5	40%	50%	1.7	2.48	$7.8
6	Nimbus	Mid-Pacific	14	20%	50%	6.8	1.39	$5.8
7	Guernsey	Great Plains	6.4	50%	50%	3.2	1.52	$4.6
8	Minidoka	Pacific Northwest	27.7	10%	20%	5.5	1.21	$2.6
9	Deer Creek	Upper Colorado	5.0	10%	20%	1.0	1.04	$0.1
10	Crystal	Upper Colorado	32	30%	30%	9.5	1.00	$0.1

Notes

[1] Plants are ranked based on the capacity addition increment with the highest NPV for each plant .

BCR - Benefit to Cost Ratio

NPV - Net Present Value

It can be concluded that 10 of the 58 plants show some promise for capacity additions that could be investigated in more detail in future studies. But it must also be concluded that if the capacity additions were implemented in the sizes indicated by this planning-level study, the resulting additions would increase the total capacity of the 58 existing Reclamation plants by less than 1%. This conclusion generally supports the assertion in the 2007 Federal study that the existing Reclamation hydroelectric plants are with few exceptions currently economically sized to the available flow.

Additional results presented in detail in subsequent chapters of this report show substantial potential for generation increases from efficiency gains that would result in substantial offsets of greenhouse gasses (GHGs) from fossil fuel-fired generation. Table ES-3 shows the ten plants with the largest opportunities for annual generation increases due to efficiency improvements at the existing units, provided the potential efficiency improvements are at least 3%. One plant in the Pacific Northwest Region, Hungry Horse, and a few plants in the Mid-Pacific Region top the list. A total of 36 plants could potentially increase their annual generation by more than 3%.

Table ES-3. Largest Efficiency Gain Opportunities – Plants with >3% Potential Increases

Rank [1]	Plant	Region	Installed Capacity (MW)	Annual Average Existing Generation (MWh/yr)	Incremental Generation from Efficiency Improvements (MWh/yr)	(%)
1	Hungry Horse	Pacific Northwest	428	930,345	49,272	5.3
2	Spring Creek	Mid-Pacific	180	590,037	36,681	6.2
3	Trinity	Mid-Pacific	140	517,251	31,209	6.0
4	New Melones	Mid-Pacific	382	470,677	29,916	6.4
5	Keswick	Mid-Pacific	117	461,014	25,762	5.6
6	Canyon Ferry	Great Plains	50	380,509	25,391	6.7
7	Palisades	Pacific Northwest	177	706,936	22,716	3.2
8	San Luis [2]	Mid-Pacific	424	304,679	20,490	6.7
9	Morrow Point	Upper Colorado	173	363,625	19,421	5.3
10	Flatiron [3]	Great Plains	94.5	241,042	14,436	6.0

Notes
[1] Plants are ranked based on the percent of additional generation from efficiency improvements over their existing annual (simulated) generation.
[2] Installed capacity of 424 MW for San Luis includes the Federal and CA shares. The Federal share is 202 MW.
[3] Installed capacity at Flatiron is 94.5 MW. Only Units 1 and 2 (81.3 MW) were included in the modeling.

In addition to generation increases, three potential ways of achieving GHG offsets were determined. Table ES-4 shows the total GHG offset opportunities for each of the five regions. GHG offsets from efficiency improvements and from capacity increases are based on the capacity addition increment from each plant that yielded the highest BCR. GHG offsets from avoided outages is a concept that was developed as part of the asset investment planning process. Results for individual plants are also presented in Chapter 9, Summary of Results.

Table ES-4. Potential GHG Reduction Opportunities by Region

Region	GHG Offsets from Incremental Generation from Efficiency Improvements		GHG Offsets from Incremental Generation from Hydraulic Capacity Increases [1]		GHG Offsets from Avoided Energy Losses [2]	
	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr
Mid-Pacific	186,818	84,961	187,735	69,129	527,348	243,476
Upper Colorado	81,627	63,134	116,853	67,246	473,221	373,756
Lower Colorado	141,191	79,612	30,833	15,993	77,649	43,783
Pacific Northwest	193,491	106,405	142,011	63,803	398,253	215,777
Great Plains	144,159	77,825	105,692	45,683	584,088	302,024

Notes

[1] Incremental GHG offsets are based on the summation of the hydraulic capacity increase increment for each plant with the highest BCR.

[2] GHG offsets from avoided energy losses are based on a generic split between on-peak and off-peak hours depending on whether the plant is operated as a peaking, base load or intermediate plant.

GHG - Greenhouse Gas

Costs and economic benefits were not assigned to the efficiency gains or greenhouse gas offsets in this study. A cost/benefit analysis was not performed for potential efficiency gains because this more detailed level of analysis is performed in the Asset Investment Planning Tool that is included in a separate task under the current overall contract. GHG offsets were not assigned dollar values because there is currently a great deal of uncertainty regarding their future valuation.

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Contents

Tables

Figures

Appendices

Abbreviations and Acronyms

%	percent
$/kW	dollars per kilowatt
$/kW-yr	dollars per kilowatt per year
$/MWh	dollars per megawatt hour
AIP	Asset Investment Planning
BCR or B/C	benefit to cost ratio
cfs	cubic feet per second
CH_4	methane
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
CO_2e/yr	carbon dioxide equivalents per year
DO	dissolved oxygen
EIA	Energy Information Administration
EMM	Electricity Market Module
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GWh	gigawatt hour
HMI	Hydropower Modernization Initiative
INEEL	Idaho National Engineering and Environmental Laboratory
kW	kilowatt
lb/MWh	pounds per megawatt-hour
MB	megabyte
MW	megawatt
MWh	megawatt hour
N_2O	nitrous oxide
NERC	North American Electric Reliability Corporation
NPV	net present value
O&M	operations and maintenance
PLEESM	Planning Level Energy and Economics Study Model
Reclamation	United States Department of the Interior, Bureau of Reclamation
TPUD	Trinity Public Utilities District
U.S.	United States
USACE	U.S. Army Corps of Engineers

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Chapter 1 Introduction

The United States Department of the Interior, Bureau of Reclamation (Reclamation) has been tasked by the Secretary of Interior and the Commissioner of Reclamation to determine the potential for generator uprating and turbine efficiency gains at all Reclamation hydropower projects. In conversations with the U.S. Army Corps of Engineers (USACE), it came to the attention of the Power Resources Office that there was an ongoing effort to not only quantify this potential at USACE projects, but to assess the investment needs of 54 USACE projects and to develop a tool to provide ongoing analysis. The USACE has contracted with MWH Americas to conduct this study.

Reclamation has partnered with the USACE Hydropower Modernization Initiative (HMI) effort to assess the investment needs of all Reclamation hydropower projects, and as a part of this effort, to quantify the uprating and efficiency gains that can be made at these facilities. The work covers 58 Reclamation hydropower projects in five Regions. This study was authorized as a part of USACE Contract No. W9127N-10-D-0004 with MWH Americas, Task Order No. 2, Hydropower Modernization Initiative, Bureau of Reclamation.

Scope

The scope of work for this study is contained in the following tasks outlined as a part of Task No. 2, Hydropower Modernization Initiative, Bureau of Reclamation:

<u>Task 5: Implement Analytical Model to Assess Capacity and Efficiency Gain Opportunities</u>. This resource assessment should quantify Reclamation's potential capacity and efficiency gains through equipment upgrades within existing environmental, water delivery, and other regulatory constraints for (initially) 58 Reclamation power plants. All opportunities must include a benefit/cost ratio and must be ranked according to greatest benefit. The results of this modeling will be reported independently (Reference Task 7) and incorporated into the Investment Plans.

<u>Task 6: Develop Environmental and Climate Change Benefits</u>. The Contractor shall develop environmental criteria including quantitative and qualitative criteria related to climate change, greenhouse gas (GHG) reduction, and other site specific environmental benefits and/or impacts to habitat, water quality or recreational activities. Climate change benefits are to be based on energy production estimates of each project. The environmental and climate change

benefits estimates shall be integrated into the Analytic Model development task (Reference Task 5).

Task 7: Prepare a Final Report on Capacity and Efficiency Gain Opportunities. The Contractor shall prepare a final report which describes the methodologies used, the data quality measures taken, the analytical models developed, the capacity/efficiency gains that can be made at Reclamation facilities, the benefit/cost ratio of those opportunities, and the environmental and climate change benefits.

Objectives

The objectives of the potential capacity and efficiency gains study can be briefly summarized as follows:

- Assess the potential for capacity additions at each of 58 Reclamation plants with existing hydropower;
- Estimate costs for the capacity additions;
- Present capacity addition results in terms of benefit to cost ratios (BCR) and net present values (NPV);
- Provide quantitative results for potential GHG reductions;
- Estimate energy gains through efficiency increases;
- Summarize the methodology and results in a report.

Because the optimum capacity addition at each plant was not known in advance, results for a range of capacity additions were developed at each plant. A number of major steps were required to arrive at the final BCR and NPV results, which included:

- Determine the energy associated with each increment of capacity addition at each plant;
- Develop energy values ($/MWh) and capacity values ($/kW-yr) by region over the economic period of analysis;
- Develop construction, mitigation, and operation and maintenance (O&M) costs for each increment of capacity addition;
- Develop an economic methodology and parameters that will provide the final BCR and NPV results;
- Quantify GHG reduction opportunities from capacity increases, efficiency gains, outage reductions;
- Develop a data quality rating for each plant as a measure of the quality and completeness of the data input to the energy model;

Each of these major steps and the final results are presented in the following chapters of the report.

Limitations

Due to the large number of plants involved, these studies were performed at the planning-level (screening or reconnaissance-level), not at the feasibility-level. Future studies could refine the results for individual plants that showed promise for capacity additions. This study is suitable for evaluating, screening and prioritizing across the group of 58 Reclamation plants. Future studies of specific plants would be required to evaluate the final feasibility of specific capacity additions and/or efficiency improvements at specific plants.

No site visits to the existing hydroelectric plants were made within the scope of this study. Site specific investigations of the physical or operational potential to add capacity were not conducted for this study, but could be the focus of future more detailed studies at selected plants. Physical and operational limitations could preclude capacity additions at some plants.

Ongoing plans and plant rehabilitation activities at various facilities at Reclamation have not been included in this report. This report is based on the currently available completed capacities at the existing plants.

Cost estimates were based on parametric equations, which is an appropriate method for a planning-level study.

The few pumped-storage units at the existing plants were simulated as conventional hydro units. Full consideration of the hourly operation and special economics of pumped storage units would essentially require a separate study that is beyond the scope of this study.

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Chapter 2
Summary of Reclamation Existing Hydroelectric Facilities

Existing Hydroelectric Facilities

This chapter provides background information on the existing Reclamation hydroelectric plants included in this study. Much of the information in this chapter was either supplied by Reclamation personnel or obtained from the Reclamation web site. The Reclamation facilities and operations are divided into five regions, as shown on Figure 2-1.

Figure 2-1. Reclamation Regions

Of the 58 Reclamation facilities with existing hydropower plants included in this report, 21 are in the Great Plains Region, 3 are in the Lower Colorado Region, 12 are in the Mid-Pacific Region, 10 are in the Pacific Northwest Region, and 12 are in the Upper Colorado Region. The 58 hydropower plants have a total of 194 units that have a combined total of 14,966,186 kW (14,966 MW) of capacity.

Of the 58 existing hydropower plants, Grand Coulee alone has about 45% of the total generating capacity. Grand Coulee includes 27 conventional hydro units and 6 pump-generating units. About 68% of the total Reclamation generating capacity is contained in three plants, which are Hoover, Glen Canyon, and Grand Coulee. The location of the existing plants is shown on Figure 2-2.Table 2-1 presents a summary of data for the 58 existing Reclamation hydropower plants.

Figure 2-2. Reclamation Existing Hydroelectric Plant Locations

Table 2-1. Reclamation Existing Hydroelectric Plants

Plant Number	USBR Region Name	Project Name	Site Name	Location	In Service Date	Number of Units	Total Nameplate Capacity (kW)
1	Great Plains	Kendrick	Alcova	Alcova, WY	Jul-55	2	41,400
2	Great Plains	Colorado-Big Thompson	Big Thompson	Loveland, CO	Apr-59	1	4,500
3	Great Plains	Pick-Sloan Mo. Basin	Boysen	Thermopolis, WY	Aug-52	2	15,000
4	Great Plains	Pick-Sloan Mo. Basin	Buffalo Bill	Cody, WY	Jul-92	3	18,000
5	Great Plains	Pick-Sloan Mo. Basin	Canyon Ferry	Helena, MT	Dec-53	3	50,000
6	Great Plains	Colorado-Big Thompson	Estes	Estes Park, CO	Sep-50	3	45,000
7	Great Plains	Colorado-Big Thompson	Flatiron	Loveland, CO	Jan-54	3	94,500
8	Great Plains	Pick-Sloan Mo. Basin	Fremont Canyon	Alcova, WY	Dec-60	2	66,800
9	Great Plains	Pick-Sloan Mo. Basin	Glendo	Glendo, WY	Dec-58	2	38,000
10	Great Plains	Colorado-Big Thompson	Green Mountain	Kremmling, CO	May-43	2	26,000
11	Great Plains	North Platte	Guernsey	Guernsey, WY	Jul-10	2	6,400
12	Great Plains	Shoshone	Heart Mountain	Cody, WY	Dec-48	1	5,000
13	Great Plains	Pick-Sloan Mo. Basin	Kortes	Sinclair, WY	Jun-50	3	36,000
14	Great Plains	Colorado-Big Thompson	Marys Lake	Estes Park, CO	May-51	1	8,100
15	Great Plains	Fryingpan-Arkansas	Mt. Elbert	Twin Lakes, CO	Jun-81	2	200,000
16	Great Plains	Pick-Sloan Mo. Basin	Pilot Butte	Morton, WY	Jan-10	2	1,600
17	Great Plains	Colorado-Big Thompson	Pole Hill	Loveland, CO	Jan-54	1	38,238
18	Great Plains	Kendrick	Seminoe	Sinclair, WY	Aug-39	3	51,750
19	Great Plains	Pick-Sloan Mo. Basin	Shoshone	Cody, WY	Jun-92	1	3,000
20	Great Plains	Pick-Sloan Mo. Basin	Spirit Mountain	Cody, WY	Oct-94	1	4,500
21	Great Plains	Pick-Sloan Mo. Basin	Yellowtail	Hardin, MT	Aug-66	4	250,000
22	Lower Colorado	Parker-Davis	Davis	Bullhead City, AZ	Jan-51	5	255,000
23	Lower Colorado	Boulder Canyon	Hoover	Boulder City, NV	Sep-36	19	2,078,800
24	Lower Colorado	Parker-Davis	Parker	Parker Dam, AZ	Dec-42	4	120,000
25	Mid-Pacific	Central Valley	Folsom	Folsom, CA	May-55	3	207,000
26	Mid-Pacific	Central Valley	Judge Francis Carr	French Gulch, CA	May-63	2	154,400
27	Mid-Pacific	Central Valley	Keswick	Redding, CA	Oct-49	3	117,000
28	Mid-Pacific	Central Valley	Lewiston	Lewiston, CA	Feb-64	1	350
29	Mid-Pacific	Central Valley	New Melones	Jamestown, CA	Jun-79	2	382,000
30	Mid-Pacific	Central Valley	Nimbus	Folsom, CA	May-55	2	13,500
31	Mid-Pacific	Central Valley	O'Neill	Los Banos, CA	Nov-67	6	25,200
32	Mid-Pacific	Central Valley	San Luis (1)	Los Banos, CA	Mar-68	8	202,000
33	Mid-Pacific	Central Valley	Shasta	Redding, CA	Jun-44	7	714,000
34	Mid-Pacific	Central Valley	Spring Creek	Redding, CA	Jan-64	2	180,000
35	Mid-Pacific	Washoe	Stampede	Truckee, CA	Jan-88	2	3,650
36	Mid-Pacific	Central Valley	Trinity	Redding, CA	Feb-64	2	140,000
37	Pacific Northwest	Boise	Anderson Ranch	Mountain Home, ID	Dec-50	2	40,000
38	Pacific Northwest	Boise	Black Canyon	Emmet, ID	Dec-10	2	10,200
39	Pacific Northwest	Boise	Boise River Diversion	Boise, ID	May-10	3	3,450
40	Pacific Northwest	Yakima	Chandler	Benton City, WA	Feb-56	2	12,000
41	Pacific Northwest	Columbia Basin	Grand Coulee	Grand Coulee, WA	Mar-41	33	6,809,000
42	Pacific Northwest	Rogue River Basin	Green Springs	Ashland, OR	May-60	1	17,290
43	Pacific Northwest	Hungry Horse	Hungry Horse	Columbia Falls, MT	Oct-52	4	428,000
44	Pacific Northwest	Minidoka	Minidoka	Rupert, ID	May-10	4	27,700
45	Pacific Northwest	Palisades	Palisades	Palisades, ID	Feb-57	4	176,564
46	Pacific Northwest	Yakima	Roza	Yakima, WA	Aug-58	1	12,937
47	Upper Colorado	Colorado River Storage	Blue Mesa	Gunnison, CO	Sep-67	2	86,400
48	Upper Colorado	Colorado River Storage	Crystal	Montrose, CO	Jun-78	1	31,500
49	Upper Colorado	Provo River	Deer Creek	Heber, UT	Feb-58	2	4,950
50	Upper Colorado	Rio Grande	Elephant Butte	Truth or Consequences, NM	Nov-40	3	27,945
51	Upper Colorado	Colorado River Storage	Flaming Gorge	Dutch John UT	Nov-63	3	151,950
52	Upper Colorado	Seedskadee	Fontenelle	La Barge, WY	May-68	1	10,000
53	Upper Colorado	Colorado River Storage	Glen Canyon	Page, AZ	Sep-64	8	1,320,000
54	Upper Colorado	Collbran	Lower Molina	Molina, CO	Dec-62	1	4,860
55	Upper Colorado	Dolores	McPhee	Cortez, CO	Dec-92	1	1,283
56	Upper Colorado	Colorado River Storage	Morrow Point	Montrose, CO	Dec-70	2	173,334
57	Upper Colorado	Dolores	Towaoc	Cortez, CO	May-93	1	11,495
58	Upper Colorado	Collbran	Upper Molina	Molina, CO	Dec-62	1	8,640
Totals						**194**	**14,966,186**

Note (1): For San Luis, 202,000 kW represents the Federal share of the 424,000 kW installed capacity. The plant is operated by the State of California.

Reclamation Uprating Program

Following the 1973 oil embargo, a review was made of Reclamation's powerplants to determine if they could be uprated to a higher capacity and to produce more energy. Uprating existing hydroelectric powerplants to fully utilize the available water resource for additional energy and peaking capacity was recognized as one of the better long range additions that could be made to help solve the energy problem. In 1978, the Bureau of Reclamation and the Department of the Interior established, as one of their major program goals, the investigating and implementing of all viable opportunities to improve existing plants by modernizing and uprating the generating equipment. Since 1978, Reclamation initiated a power uprating program to increase the capacity of Reclamation facilities as funding and unit availability allowed. In addition, there have been a number of generator rewinds where no appreciable uprate potential existed but winding condition was poor.

Uprating hydroelectric generator and turbine units at existing power plants are one of the most immediate, cost effective, and environmentally acceptable means for developing additional electrical power. As a result of the uprating program, the generating capacity of over one-third of Reclamation's hydroelectric generators has been increased, with almost a 50 percent average increase in generating capacity of each unit.

An uprate normally involves an increase in rating of more than 15 percent, which in turn necessitates a review of the capability and limits of all of the power equipment, from the penstock through the turbine, generator, bus, switchgear, transformer, and transmission system. These systems can then either be retained, modified or replaced in order to develop and accommodate the selected uprate level.

A good indicator for considering uprating a generator is when the turbine capability substantially exceeds the generator capability at normal operating heads. Most Reclamation turbines are designed to provide rated output (or nameplate capacity) at rated head. Since the rated head was chosen far enough below the maximum operating head to ensure the generator overload capacity could be utilized, reservoirs often operate at heads much higher than rated and the turbine is usually capable of more mechanical output than the generator can convert to electrical energy. In these and other situations, increased rating and efficiency can be obtained by runner replacement. For pre-1960 turbines, it is frequently possible to obtain output increases as high as 30 percent and efficiency increases of 1.5 percent in comparison to new original equipment by replacing existing runners with runners of modern design. A summary of the unit uprates performed by Reclamation to date is presented in Table 2-2. Uprate projects that are currently in-progress are not included in Table 2-2.

Between the original sizing of the hydroelectric plants and the uprating program, Reclamation regional staff has previously indicated that they believe there is little or no surplus water at existing Reclamation hydroelectric plants to warrant additional units. In the recent study, *Potential Hydroelectric Development at Existing Federal Facilities* (U.S. Department of the Interior, et al, 2007) that is commonly known as the 1834 Study, it was stated that with few exceptions, the existing Reclamation generation facilities have been sized to their available hydrology, many over 30 years ago. There was such confidence in this statement that all of the existing Reclamation hydroelectric facilities were completely excluded from the 1834 study, a planning-level study of potential hydroelectric development at existing Federal facilities.

The current studies described in this report began and were performed with no pre-conceived conclusions on the potential for, or viability of, capacity additions at the existing Reclamation hydroelectric plants.

Table 2-2. Reclamation Unit Uprates

Plant	Units	Each Unit Old Rating (kW)	Each Unit New (kW)	Percent Increase	Added kW Plant	Year Uprate Completed
Anderson Ranch	2	13,500	20,000	48.1%	13,000	1983
Black Canyon	2	4,000	5,100	27.5%	2,200	1995
Blue Mesa	2	30,000	43,200	44.0%	26,400	1995
Boise River Diversion	3	500	1,150	130.0%	1,950	2005
Crystal	1	28,000	35,000	25.0%	7,000	2004
Flaming Gorge	3	36,000	50,495	40.3%	43,485	1992
Flatiron	2	31,500	43,020	36.6%	23,040	1983
Fremont Canyon	2	24,000	33,400	39.2%	18,800	1989
Glen Canyon	2	118,750	165,000	38.9%	92,500	1987
Glen Canyon	3	118,750	165,000	38.9%	138,750	2006
Glen Canyon	3	118,750	165,000	38.9%	138,750	2009
Glendo	2	12,000	19,000	58.3%	14,000	1983
Hoover	2	82,500	127,000	53.9%	89,000	1989
Hoover	12	82,500	130,000	57.6%	570,000	1992
Hoover	1	95,000	130,000	36.8%	35,000	1992
Hoover	1	40,000	61,500	53.8%	21,500	1992
Hoover	1	50,000	68,500	37.0%	18,500	1992
Hungry Horse	4	71,250	107,000	50.2%	143,000	1993
Judge Francis Carr	2	70,722	77,200	9.2%	12,956	2010
Keswick	3	25,000	39,000	56.0%	42,000	1991
Minidoka	1	2,400	3,000	25.0%	600	1996
Morrow Point	2	60,000	86,667	44.4%	53,334	1993
Palisades	2	28,500	44,141	54.9%	31,282	1994
Palisades	2	30,875	44,141	43.0%	26,532	1995
Shasta	2	75,000	142,000	89.3%	134,000	2008
Shasta	3	75,000	142,000	89.3%	201,000	2005
Trinity	2	50,000	70,000	40.0%	40,000	1984
Totals	**67**	**3,875,094**	**5,813,673**	**48.4%**	**1,938,579**	

Generator rewinds can increase the nameplate capacity of the units. Many of the older Reclamation generators were purchased with a continuous overload capability of 15 percent above rated output (“nameplate rating”), which was the effective standard for rating generators at that time. When “rewinding" a generator, the new winding is purchased with a base rating equal to or greater than 115 percent of the original generator nameplate rating, using the appropriate allowable temperature rise consistent with the insulation class of the new winding. If the new winding is capable of operation at levels higher than 115% of the original nameplate rating, the machine would typically still be limited to operation at its new base rating level, unless the mechanical and structural characteristics of the generator were confirmed to be capable of higher loads. Ratings of the bus, unit breakers, transformer, etc. are examined for capability to accommodate the new generator rated capacity, and detailed studies and selected replacements are performed as required to accommodate the new output capacity.

Table 2-3 presents a summary of the unit rewinds to date of Reclamation generators where the new base rating of the generators was 115% of their original nameplate rating. Note that, in these cases, only the *nameplate* rating changed; the actual generating capacity did *not* increase.

Table 2-3. Reclamation Unit Rewinds

Plant	Units	Year	kW Added
Alcova	2	2001-2002	5,400
Davis	5	1974-2003	30,000
Elephant Butte	3	1990-2002	3,645
Flatiron	2	1978-96	1,660
Folsom	3	1962-72	36,720
Grand Coulee	18	1968-2004	306,000
Green Mountain	2	1982	2,400
Green Springs	1	2005	1,290
Guernsey	2	1993	1,600
Pole Hill	1	1987	4,988
Seminoe	3	1978-80	19,350
Spring Creek	2	1981-82	30,000
Total	**44**		**443,053**

So, from the above tables, 67 units have had increased nameplate capacity and increased actual generating capacity, and an additional 44 units have had increased nameplate capacity without any increase in actual generating capacity. A total of 111 of the 194 units (57%) have had an uprate or a rewind.

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Chapter 3
Energy Model

An energy model is the fundamental tool used to determine the increased energy output, and therefore the benefit, that is available from a capacity addition. An energy model can also be called a power study model or an operation model. This chapter details the energy model used to simulate the 58 existing Reclamation hydroelectric plants and the capacity additions.

Objectives of PLEESM

The energy model used in this study is called the Planning Level Energy and Economics Study Model (PLEESM). PLEESM is a new model designed specifically for the objective of performing planning-level simulation of the energy production of a large number of hydroelectric plants in a relatively short amount of time. The model has also been directed at the task of investigating several alternative capacity additions at each plant in a single run. The determination of benefit/cost ratios and net present values is done within PLEESM for each capacity addition alternative. PLEESM was also designed to provide results for input to the Asset Investment Planning (AIP) tool. As a planning level model, PLEESM was intended to find the more promising of many alternatives. It was not intended to simulate energy production in the ultimate detail that would need to be incorporated into feasibility or final design studies.

Methodology

PLEESM is a sequential streamflow simulation model that operates on a daily time increment. PLEESM is an Excel© spreadsheet based model that was designed to simulate the daily energy generation at multiple hydroelectric plants for a period of up to 30 years. A key simplification of the PLEESM model is that total reservoir outflow is an input to the model, whereas reservoir inflow is input to some other power study models and outflow is determined by the model. Using reservoir outflow as model input is made possible in this study because all of the reservoirs have existed for many years. Using historic reservoir outflows as input data also implies that future reservoir operation will be essentially the same as historical/existing reservoir operation.

PLEESM includes provision for the modeling of up to eight separate existing turbine-generator units that may have varying capacities. PLEESM allocates flow to units in order, such that the hydraulic capacity of Unit 1 is completely utilized on a given day before any flow is allocated to Unit 2, with a similar pattern repeated through Unit 8. Herein this utilization pattern is termed logical units, and it contrasts with the roughly equal utilization that would typically occur with actual physical units. The logical unit concept is incorporated into the model for two reasons: (1) the same procedure clearly determines the flow allocated to capacity additions of different sizes; and (2) if one, two, or three units were on outage, the amount of generation lost can be directly determined for input to the AIP tool. For the two plants that had more than eight existing units, Grand Coulee and Hoover, units were aggregated into eight logical units. As discussed below in Simulation Accuracy, this assumption/ simplification still yielded good correlation with actual historical generation.

The PLEESM model consists of a single calculation engine with specific plant data read-in from other spreadsheets. The plant to be simulated is specified from a drop-down list. Although the model operates on a daily time increment, provision for the characterization of hourly or peaking operation is included by the specification of the percentage of generation that occurs on-peak and off-peak. Unless more specific information was supplied for a plant, peaking plants were assumed to generate 85% of their total energy on-peak, base load plants had 46% of their energy on-peak, and combined operation plants had 65% of the total energy on-peak, with all remaining energy being off-peak. It is noted that pumped-storage units are simulated as conventional hydroelectric units, without consideration of the pumping cycle. The detailed hourly operation cycles and the economic justification for pumped-storage units are different from conventional units and beyond the scope of this study.

Because the optimum potential capacity addition was not known in advance, five different capacity additions were tested to provide a range of values from which a curve of benefit to cost ratios and net present values could be plotted. The potential capacity additions were taken as 10%, 20%, 30%, 40%, and 50% of the existing nameplate plant capacity. Prior to modeling of the plants, it was thought that the maximum benefit to cost ratio would occur at 50% capacity addition or less. In addition to the up to eight existing units, the capacity increases were developed in the model as five additional virtual units. Because the method of capacity addition is unspecified in this study, the five additional virtual units should not be taken as corresponding to the addition of five actual units.

PLEESM also incorporates the economic cost and benefit calculations that are described in subsequent chapters of this report. The detailed results included in Appendix A were copied directly out of PLEESM. Due to the detailed energy and economics calculations for a total of 13 logical units, the model is a rather large spreadsheet that is about 35 MB in size.

Model Input

Model input data for the simulation of hydroelectric generation is divided into two general types, time-series data and plant parameter data. Both of these types of data were supplied for each of the 58 plants by Reclamation. Where some of the data was unavailable for certain plants, reasonable assumptions or calculation procedures were used to estimate the necessary data.

Time-series data input to the model included:

- Total outflow (all hydraulic pathways)
- Turbine flow
- Head, or reservoir elevation, and tailwater
  - Gross head input directly
  - Reservoir elevation and tailwater used to calculate gross head (time-series or rating curve)
- Existing historic generation; used for model verification

Plant parameter data included the following:

- Hydraulic capacity of each unit
- Required non-power releases (irrigation, fish, etc.)
- Unit efficiencies, existing and modified
- Head losses
- Percent of time the plant generation is on-peak and off-peak

Model Output

Model output was organized into tables and plots on the various model tabs. Model output includes:

- Long-term average energy – original and upgraded units
- Monthly and annual on-peak and off-peak energy
- Energy potentially lost in outages of various duration for up to three units out
- Month to start outage to minimize the financial impact from the generation lost
- Energy gained with capacity increases
- Plots and summary tables

- Sheet with tabulated parameters for import to the AIP tool
- Economics

Figures 3-1 through 3-4 are examples of plots for Keswick that are automatically developed within PLEESM for each plant. Figure 3-1 is a plot of flow duration through each unit and for five potential capacity additions. Keswick has three existing units (Units 1-3) and Figure 3-1 shows that the great majority of the available flow can by utilized by the existing units. The five smaller color bands (virtual Units 9-13) are the flow that could be utilized by the five potential increments of additional capacity. Figure 3-2 shows the monthly distribution of flow through each of the existing units and potential capacity addition increments. Figures 3-3 and 3-4 show typically good agreement between simulated and actual generation for monthly and daily generation, respectively. Figure 3-4 displays daily generation developed from monthly data by making all daily data input equal to the monthly average.

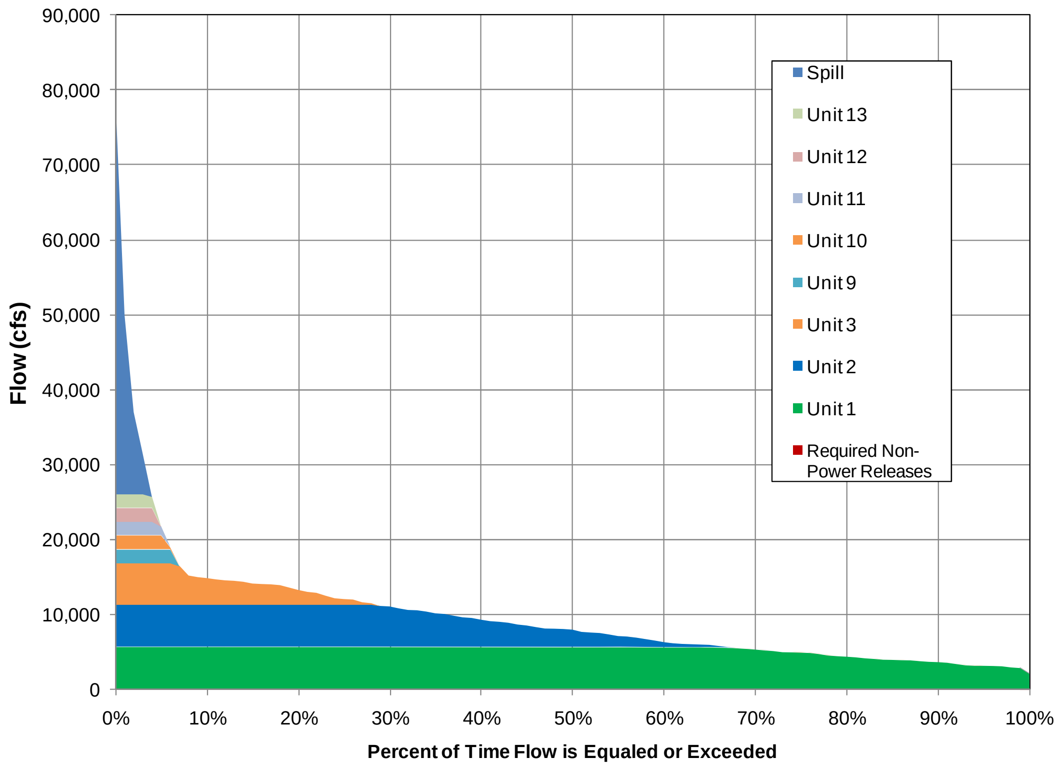

Figure 3-1. Flow Thru Existing Keswick Units and Potential Capacity Additions

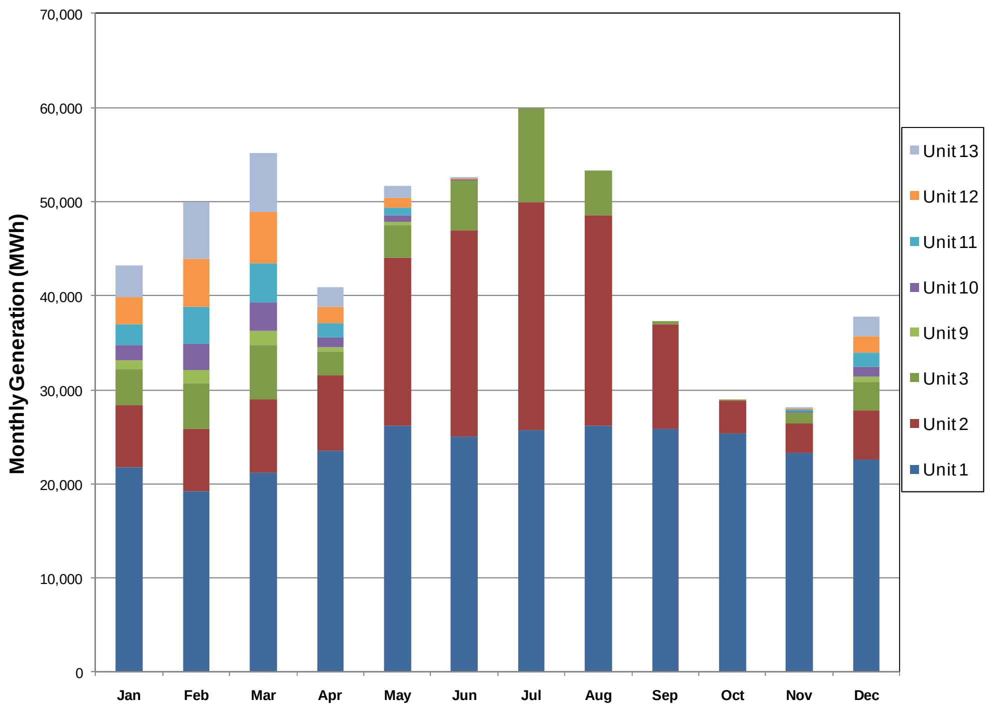

Figure 3-2. Keswick Average Monthly Energy Distribution

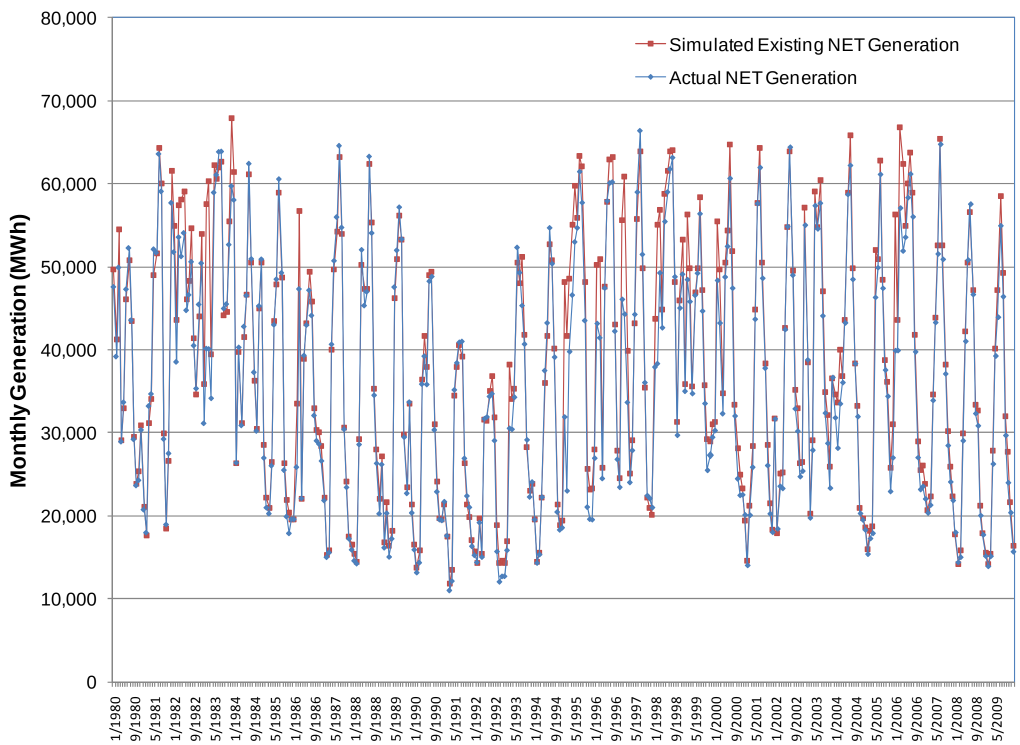

Figure 3-3. Keswick Simulated and Actual Monthly Generation

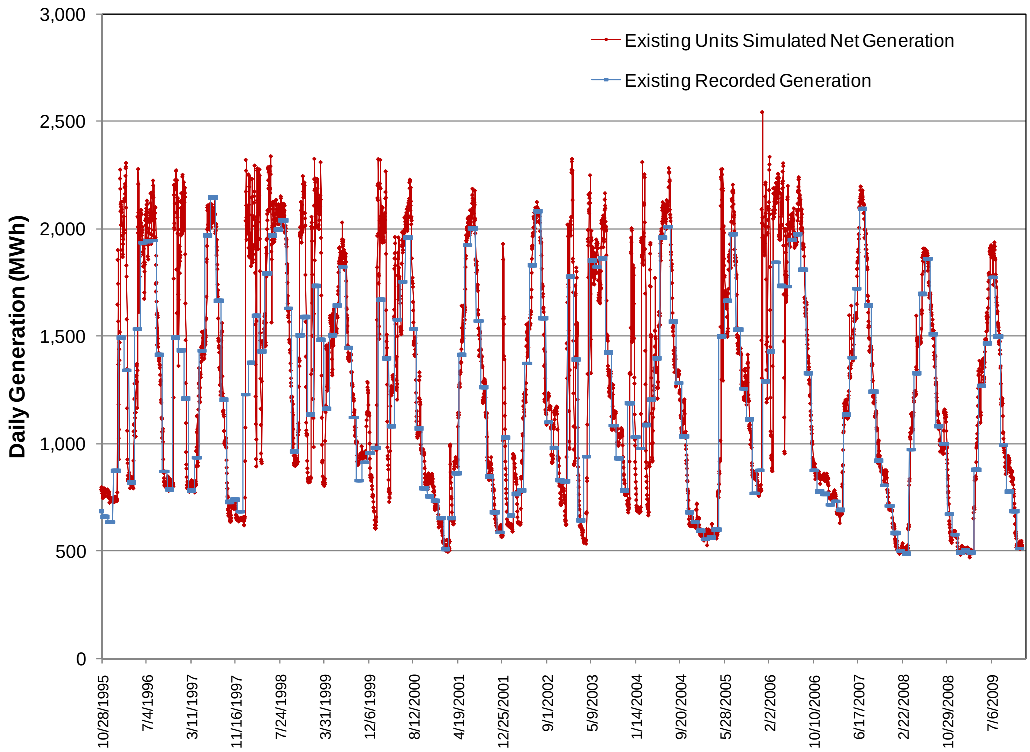

Figure 3-4. Simulated and Actual Keswick Daily Generation

Interface with AIP Tool

PLEESM was designed to provide results for input to the AIP tool. The AIP tool incorporates risk management principles to guide hydroelectric equipment investments to maximize the return on investment for a given level of service. Parameters determined in PLEESM and transferred to the AIP tool include:

- Existing and upgraded unit on-peak and off-peak average monthly energy in logical unit order
- Upgraded unit on-peak and off-peak average monthly energy corresponding to a selected capacity increase
- For outages having durations of one to twelve months, the month when the outage should be scheduled to start to minimize financial losses is determined.

Simulation Accuracy

Simulation accuracy is a measure of the agreement between the simulated and recorded generation. Reasonable agreement between simulated and actual generation validates the data input and the modeling procedure. With few exceptions, the simulation accuracy was generally good. Simulated generation was usually higher than actual generation for at least three reasons. First, simulation of the existing units assumed the efficiencies would correspond to new, original condition. This was due to the required interface with the AIP tool which performs the unit degradation with age. Second, uprates have occurred over time such that simulated generation based on the current capacity will show greater generation than actual data based on the pre-uprate recorded generation. And finally third, historic outages were not directly simulated. The simulation accuracy is summarized in Table 3-1.

Table 3-1. Summary of Simulation Accuracy

% Difference between Simulated and Actual Generation	Number of Plants	% of Total	Cumulative % of Total
± 0 - 5%	21	37%	37%
± 5 - 10%	19	33%	70%
± 10 - 15%	8	14%	84%
± 15 - 20%	4	7%	91%
± 20 - 25%	4	7%	98%
± 25 - 30%	1	2%	100%
± > 30%	0	0%	-

An example of how uprates affect the simulation accuracy is shown on Figure 3-5 for Palisades, which was uprated in 1994-95. For the months with the highest generation prior to 1995, the existing generation was substantially less than the simulated generation. This is because the model includes the current uprated capacity for the entire period of the simulation. For 1995 and later, the simulation is excellent, even though the simulation accuracy shows a 12% difference between simulated and actual generation.

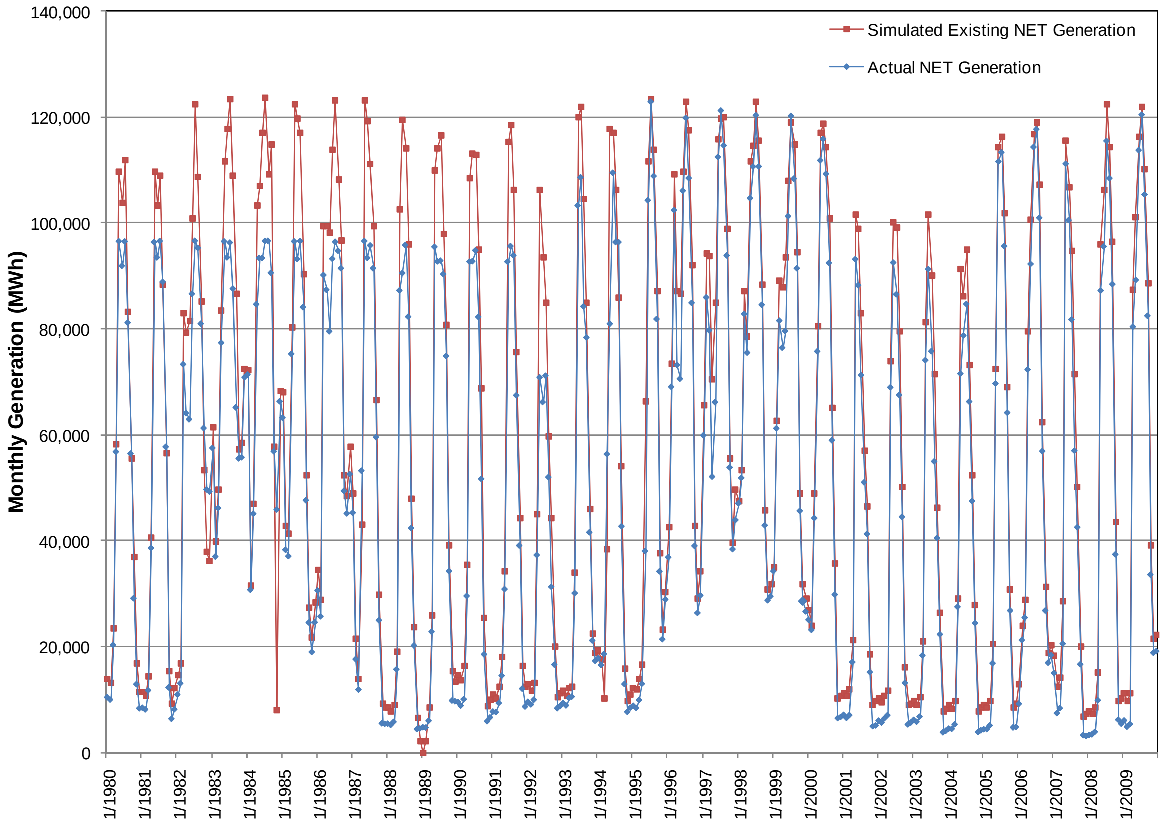

Figure 3-5. Palisades Simulated and Actual Monthly Generation

A second example is Minidoka, which had an uprate in 1996. The effects of the uprate are clearly shown in the years prior to, and after 1996. Minidoka also exhibits an apparent outage in 1996. In the more recent years, the simulation becomes excellent. Despite a simulation statistic that shows a difference between simulated and actual of almost 30%, the energy model simulation of the current configuration is as good as can be expected.

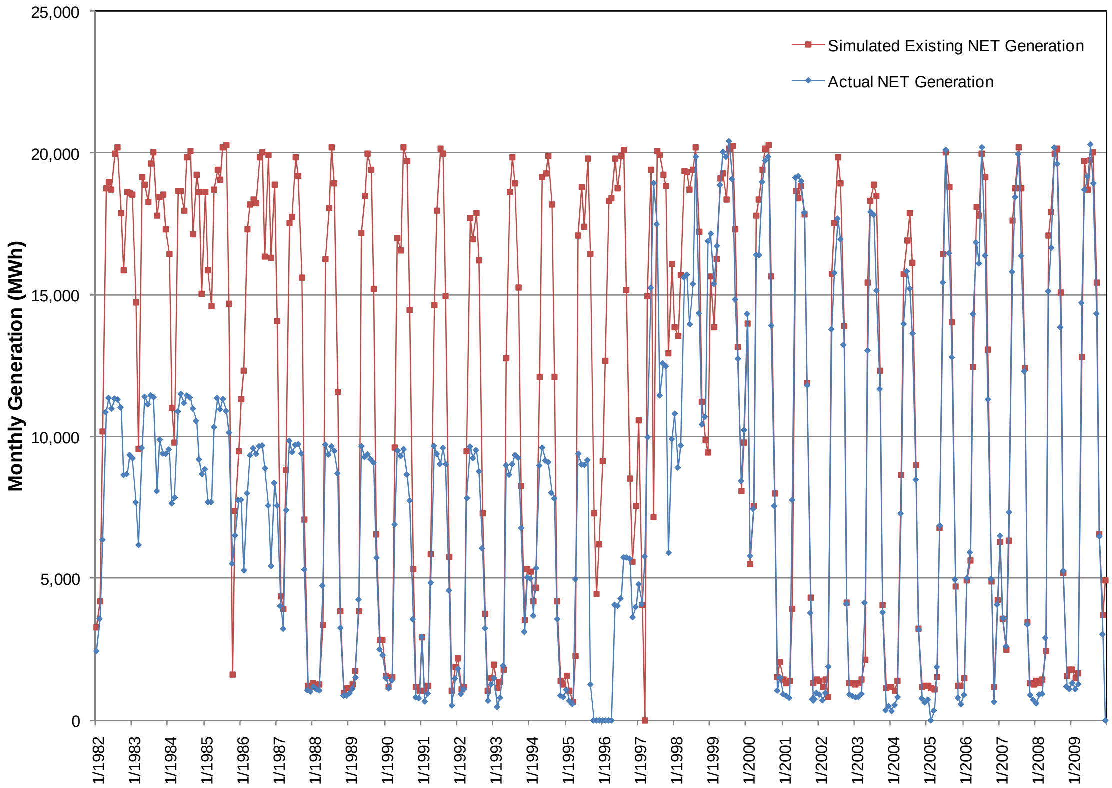

Figure 3-6. Minidoka Simulated and Actual Monthly Generation

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Chapter 4 Economics

This chapter provides the economic parameters, methodology, and example calculation details of the costs and benefits associated with the capacity additions for each plant. The economic analysis defines the capacity addition amounts that would be most beneficial from a purely economic viewpoint. This is usually determined by selecting the alternative having the maximum NPV, or the highest BCR. The BCR and NPV values can also be used as a means to rank the most beneficial capacity additions among the 58 plants.

Definitions

The following definitions define terms as they are used in this study:

- Benefit to Cost Ratio (BCR or B/C) – The present value of total benefits divided by the present value of total costs
- Discount Rate – Time value of money used to convert or aggregate costs and benefits occurring at various times to a common point in time.
- Net Present Value (NPV) – The present value of the total benefits minus the present value of the total costs.
- Nominal Values (nominal dollars, nominal discount rate) – Includes the effects of expected or historic inflation. Costs expressed in nominal dollars are in terms of the cost in the year spent. Benefits expressed in nominal dollars are in terms of the benefit in the year realized.
- Present Value – The present value provides a means to determine and compare total costs or benefits over time. A series of annual values in nominal dollars should not be totaled in an economic analysis as the dollar values are not equivalent. The discount rate is used to adjust dollar values over time to current dollar values.
- Real (or Constant Dollar) Values – Values adjusted to eliminate the effects of expected or historic inflation.
- Levelized capital cost – Represents the present value of the total capital cost and fixed O&M costs of building and operating a generating plant over its financial life, amortized to equal annual payments.

The economic analysis for this study uses nominal values.

Economic Parameters

The economic analysis was performed using several basic economic parameters and assumptions as summarized below:

- Period of economic analysis – 50 years; 2015 through 2064
- On-line date for all alternatives – 2015
- Discount rate – 4.375%. Applicable to Federal water resources planning and reflects Federal ownership (Federal Register, 2010).
- Inflation rate – 1.8%. Based on the differential between a long-term (30-year) real interest rate of 2.7% (OMB 2009) and the nominal interest rate of 4.5%, an inflation rate of 1.8% is implied.
- Energy value escalation – includes a variable annual real escalation plus 1.8% per year for inflation.
- Capacity escalation – Capacity values are constant in nominal dollars as they are assumed to represent levelized capital costs
- O&M escalation rate – 2.3% (consisting of 1.8% inflation plus 0.5% real escalation)
- Annual costs and benefits – expressed in nominal dollars
- Present value year – 2010
- Interest rate – not applicable as the construction and mitigation costs are included as a single capital cost and are not amortized

Because ownership and funding for the capacity additions is expected to be Federal, a 4.375% discount rate is applicable (OMB 2009). If private ownership and financing were involved, the discount rate would be higher and use of a different interest rate for amortization may be necessary. Depending on the ownership and financing source, the applicable discount rate could range from 4.375% to about 12%. For example, a typical discount rate used by a large investor owned utility could be about 8.0%. Because of the sensitivity of the results to the selected discount rate, examples of varying the discount rate are shown in Example Economic Results Description.

Costs and Benefits

Costs and benefits include several components that are discussed in more detail in subsequent chapters. Cost components include:

- Initial construction cost
- Mitigation costs
- Fixed and variable annual O&M costs

Benefits include annual values for:

- On-peak energy (MWh) times the annual value of on-peak energy ($/MWh)
- Off-peak energy (MWh) times the annual value of off-peak energy ($/MWh)
- Capacity ($/kW-year), which is a variable depending on the incremental capacity factor of the added capacity times the added capacity (kW)

Example Economic Results Description

Because the optimal capacity addition for any plant is not known in advance, economic results were determined for capacity additions in five increments of 10%, 20%, 30%, 40%, and 50% of the existing installed capacity. It was thought that the most beneficial capacity additions would in most cases be less than 50% of the existing installed capacity. Plotting curves of the economic results for the various capacity additions can enhance comprehension of the results.

Examples of the detailed economic results, which are provided for each of the 58 plants in Appendix A, are presented in the following figures for a hypothetical plant with an existing installed capacity of 100 MW. To show the sensitivity of the results to the range of potential discount rates, Figures 4-1, 4-2, and 4-3 have identical input except for discount rates of 4.375%, 8.0% and 12.0%. The hypothetical plant used for the figures is capable of generating substantial additional energy as shown by the total incremental capacity factor. Capacity factor is a ratio (or percent) that represents the actual generation divided by the generation that could be obtained if the incremental capacity was run at full output for the entire year. For example, 40 MW of capacity could potentially generate 350,400 MWh (40 MW times 8,760 hours in a year). If the actual annual average generation was 87,600 MWh, the capacity factor would be 25% (87,600/350,400 – times 100 to convert to a percentage).

Numerical values plotted on the following figures are tabulated above the figures. The construction and mitigation total cost represents the initial capital investment. The construction and mitigation cost is also shown in the table above the figures in terms of $/kW as a reference value. The maximum BCR ratio and the maximum net present value typically do not occur at the same capacity addition value as shown in the example.

The results show that while the maximum BCR always occurs for a 20% capacity addition, the maximum benefit to cost ratio drops from 2.85 with a discount rate of 4.375%, to 2.02 with a discount rate of 8%, to 1.50 with a discount rate of 12.0%. The maximum net present value (in millions of dollars) drops even more dramatically from $97.4 at a 40% capacity addition with a 4.375% discount rate, to $34.2 at a 30% capacity addition with an 8.0% discount rate, to $11.8 at a 30% capacity addition with a 12.0% discount rate. The range of these results should be of interest to private developers that may consider capacity additions.

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	10.0	35,040	40%	$15.5	$1,551	$22.0	$38.6	$21.9	$60.5	$38.4	2.74
20%	20.0	61,320	35%	$27.4	$1,369	$38.4	$67.5	$41.8	$109.4	$71.0	2.85
30%	30.0	78,840	30%	$38.2	$1,274	$53.2	$86.8	$59.9	$146.7	$93.6	2.76
40%	40.0	87,600	25%	$48.5	$1,211	$67.0	$96.5	$67.9	$164.4	$97.4	2.45
50%	50.0	87,600	20%	$58.3	$1,165	$80.2	$96.5	$69.9	$166.4	$86.2	2.07

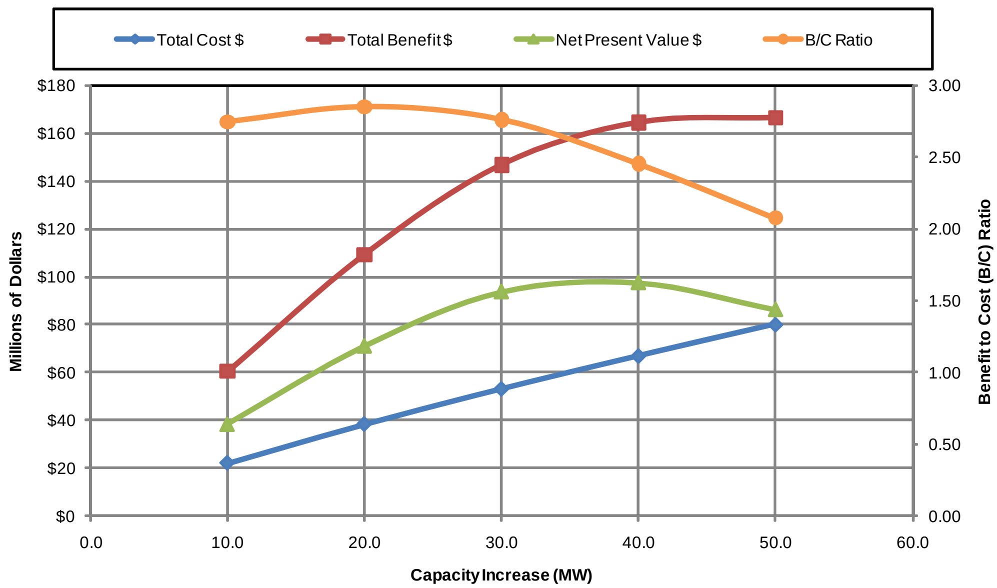

Figure 4-1. Example Economic Details Results - 4.375% Discount Rate

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	10.0	35,040	40%	$15.5	$1,551	$14.7	$17.2	$11.4	$28.6	$13.9	1.95
20%	20.0	61,320	35%	$27.4	$1,369	$25.6	$30.1	$21.8	$51.8	$26.2	2.02
30%	30.0	78,840	30%	$38.2	$1,274	$35.6	$38.7	$31.1	$69.8	$34.2	1.96
40%	40.0	87,600	25%	$48.5	$1,211	$44.9	$43.0	$35.3	$78.3	$33.3	1.74
50%	50.0	87,600	20%	$58.3	$1,165	$53.9	$43.0	$36.3	$79.3	$25.5	1.47

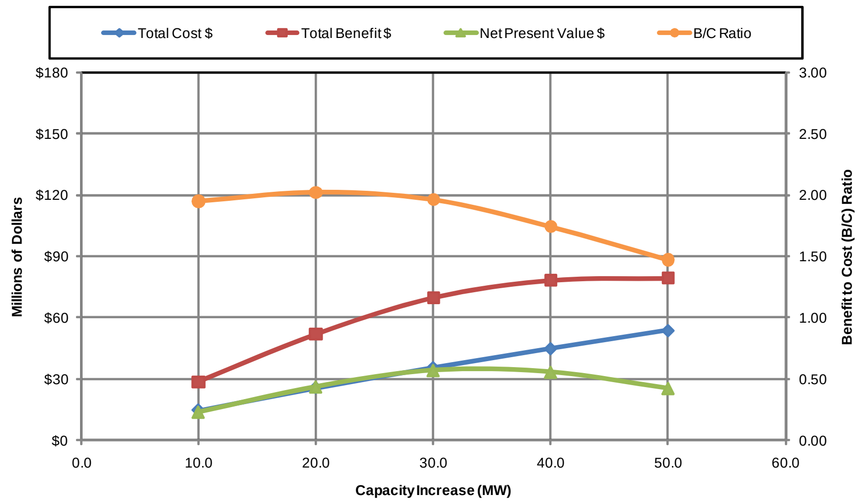

Figure 4-2. Example Economic Details Results - 8% Discount Rate

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	10.0	35,040	40%	$15.5	$1,551	$10.7	$8.9	$6.6	$15.4	$4.7	1.44
20%	20.0	61,320	35%	$27.4	$1,369	$18.8	$15.5	$12.5	$28.1	$9.3	1.50
30%	30.0	78,840	30%	$38.2	$1,274	$26.1	$20.0	$18.0	$37.9	$11.8	1.45
40%	40.0	87,600	25%	$48.5	$1,211	$33.0	$22.2	$20.3	$42.5	$9.6	1.29
50%	50.0	87,600	20%	$58.3	$1,165	$39.5	$22.2	$20.9	$43.1	$3.6	1.09

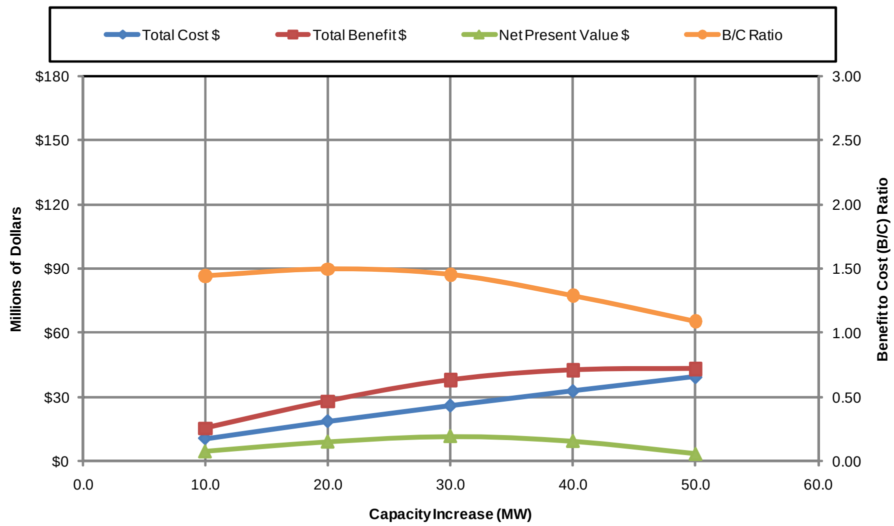

Figure 4-3. Example Economic Details Results - 12% Discount Rate

Note that Tables 4-1 through 4-3 were for a hypothetical plant with an existing installed capacity of 100 MW.

Chapter 5
Energy and Capacity Benefits

The benefits from capacity additions at the 58 plants are based on the costs of an equivalent increment of an alternative thermal plant that would be offset by the additional hydropower. Benefits are developed in more detail in the following chapters, but in a simplified and approximate manner, benefits can be expressed in the following alternative terms:

Benefits	=	capacity	+	on-peak and off-peak energy
	=	fixed costs	+	variable costs
	=	capital costs	+	operating costs
	=	(construction costs + fixed O&M) + (fuel costs + variable O&M)		

Energy Benefits

The Energy Information Administration has developed a system to provide 25 year forecasts and analyses of energy-related activities, including electricity prices as a component of the *Annual Energy Outlook* (EIA 2010a). The Electricity Market Module (EMM) represents the capacity planning, generation, transmission, and pricing of electricity. Energy values ($/MWh) for this study were developed for the appropriate EMM region. Average annual energy values were then distributed to monthly values on a regional basis to account for the seasonal timing of the additional capacity generation (EIA 2010c). EMM regions were defined by the Energy Information Administration (EIA 2010a) as shown on Figure 5-1. All of the 58 Reclamation plants in this study are in regions 11, 12, or 13.

1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-American Interconnected Network (MAN)
5 Mid-Continent Area Power Pool (MAPP)
6 New York (NY)
7 New England (NE)
8 Florida Reliability Coordinating Council (FL)
9 Southeastern Electric Reliability Council (SERC)
10 Southwest Power Pool (SPP)
11 Northwest Power Pool (NPP)
12 Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13 California (CA)

Figure 5-1. Electricity Market Module Regions

Benefits were separated into on-peak and off-peak energy values and capacity values. To provide market prices for energy and capacity, values were developed based on information available from the Department of Energy, Energy Information Administration (EIA), *Annual Energy Outlook* (EIA, 2010). The specific data used to develop the energy and capacity values is contained in a spreadsheet available on the Internet at the following location:

http://www.eia.doe.gov/oiaf/aeo/supplement/sup_elec.xls

The relevant base information is contained in Tables 82, 83, and 84 of the above referenced spreadsheet for Electric Power Projections for Regions 11, 12, and 13. The energy values used in this study do not appear directly in the EIA tables, but are calculated from information in the table.

After a review of a number of possibilities, it was determined that energy values based on the average of two methods would be most appropriate. In the first method, on-peak energy values are based on the value of gas-fired generation, while off-peak generation values are based on the value of coal-fired generation. The general formulas used in the energy value calculations are as follows:

Energy value = fuel costs + variable operating costs

Variable operating costs = 20% of fuel costs

On-peak energy fuel = gas

Off-peak energy fuel = coal

Generation in the following formula is based on the particular fuel type.

$$Energy\ value\ \left(\frac{\$}{MWh}\right) = \frac{Fuel\ price\ \left(\frac{\$}{Btu}\right) * Fuel\ consumption\ (Btu) * 1.2}{Generation\ (MWh)}$$

In the second method, regional information obtained from Federal Energy Regulatory Commission (FERC) Form 714 (Annual Electric Balancing Authority Area and Planning Authority Area Report) is used to determine the on-peak and off-peak energy values. On FERC Form 714, the system "lambda" is reported for each hour of the year, where "lambda" represents the marginal cost of electricity for the given hour. From these values, the ratio of the marginal cost of energy during on-peak and off-peak hours can be determined as a ratio to the 24-hour average marginal cost of energy. The average cost of thermal generation for the EMM region as determined from the EIA data is then adjusted by these ratios. The on-peak and off-peak energy values used for each region are taken as the average of the two methods. On-peak is the 16-hour period generally from 6 am to 10pm (more specifically, the 16 hour period with the highest values); other hours are off peak.

Figure 5-2 shows the results for real and nominal values of on-peak and off-peak energy analysis for the Northwest Power Pool area (Region 11 on Figure 5-1). Up to 2035, real escalation was as determined from the EIA data, and an annual inflation rate of 1.8% was added. For years 2045 and beyond, a real escalation rate of 0.5% was assumed, which was less than the average real escalation rate up to 2035. In the period from 2036 to 2044, annual real escalation rates were estimated that would smoothly transition from the higher real escalation rates prior to 2035 to the lower real escalation rates beginning in 2045. An annual inflation rate of 1.8% was added for all years. For 2045 and beyond, the effective energy value annual escalation rate is 2.3%.

The projections beyond 2035 are based on the calculated compounded growth rate for the last 10 years of the DOE projected horizon, 2025 to 2035. This growth rate is generally applied to extrapolate values to 2064. However, in some cases, the rate is high, resulting in unreasonable out-year values. A limiting growth rate of 0.5% was specified. If the calculated 2025 to 2035 growth rate is less than the limiting growth rate, the calculated growth rate is applied from 2036 and beyond. If the calculated 2025 to 2035 growth rate is greater than the limiting growth rate, the calculated rate is reduced linearly each year from 2036 to 2045, and the limiting growth rate is used thereafter.

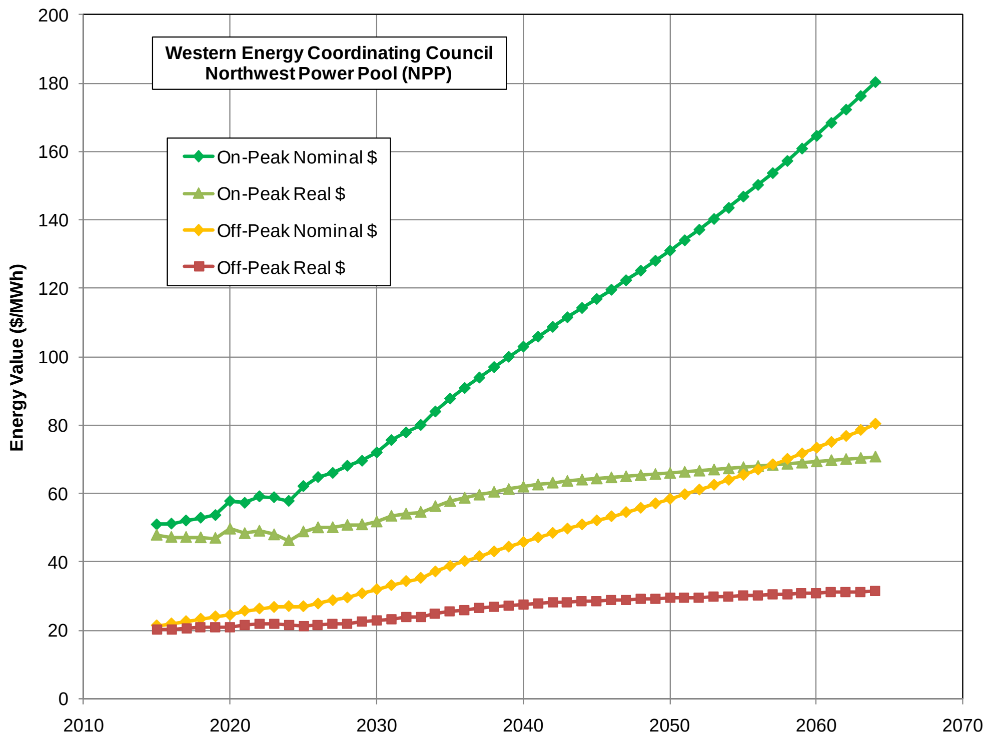

Figure 5-2. Real and Nominal Energy Values for the Northwest Power Pool

In a similar manner, Figure 5-3 shows the results for real and nominal values of on-peak and off-peak energy analysis for the Rocky Mountain Power Area (Region 12 on Figure 5-1), and Figure 5-4 shows the energy values for California (Region 13 on Figure 5-1).

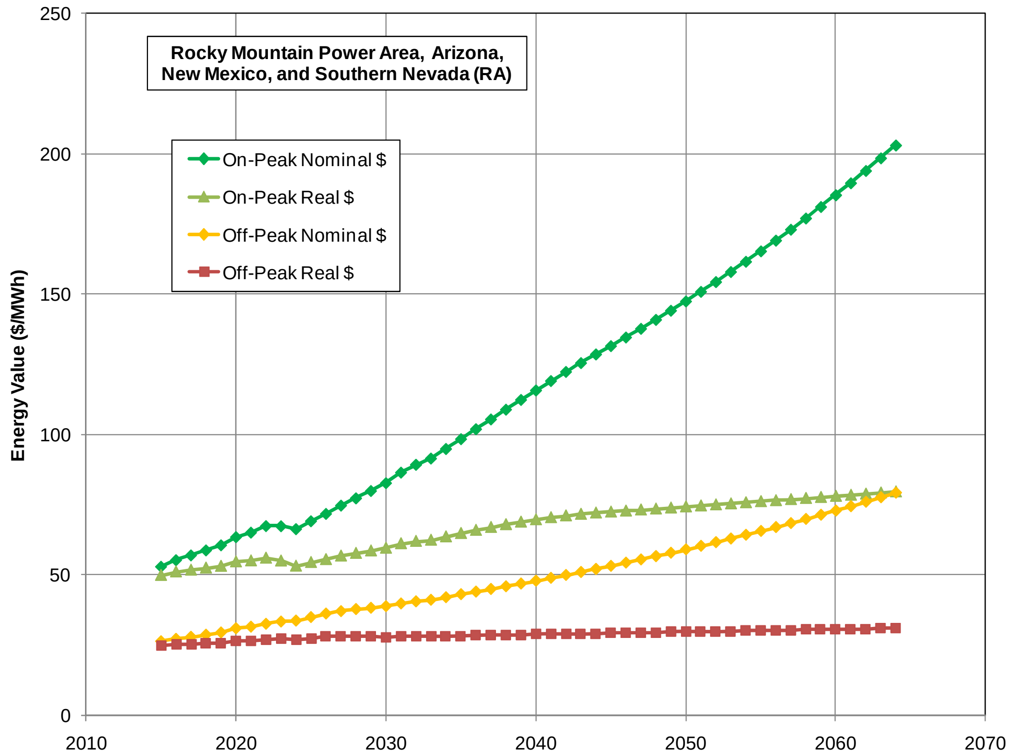

Figure 5-3. Real and Nominal Energy Values for the Rocky Mountain Power Area

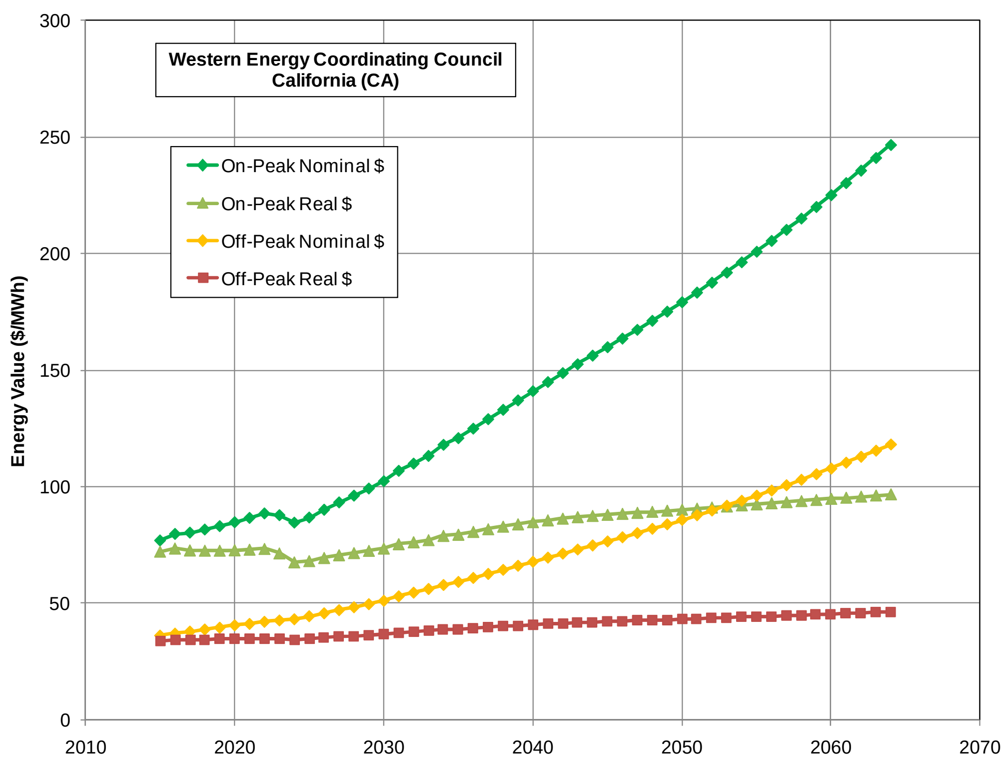

Figure 5-4. Real and Nominal Energy Values for California

Capacity Benefits

The capacity value represents the per kilowatt annualized capital cost and other fixed costs associated with the alternative thermal plant. Capacity values have the units of dollars per kilowatt per year ($/kW-yr). In some studies, benefits are developed solely from “all-in” energy values in which capacity benefits are included as a component of the energy value. In many other studies (this one included), benefits are developed from separate annual capacity and energy values. It was known in advance that many of the Reclamation plants would develop little or no additional energy as a result of the potential capacity additions. If there was zero additional energy associated with a capacity increase, the “all-in” energy values would result in zero benefits for the capacity increase. At a minimum, because the existing Reclamation plants have upstream regulating reservoirs, the added capacity would have some potential to occasionally move some energy from off-peak hours to higher-valued on-peak hours. Additionally, added hydropower capacity may have increasing value in the future for integration of renewable energy, such as wind power. Including separate capacity and energy values in the structure of the economic analysis provides for the explicit variable inclusion of capacity valuation, and for the future capability to adjust the value of added capacity for cases with little or no added energy.

The capacity values were developed from a note associated with the *Annual Energy Outlook* 2010 (EIA 2010b). A $/kW-yr capacity value can be derived by using EIA projections of capacity additions and EIA estimates of capital costs. Because the EIA data is based on U.S. average levelized values, the capacity values were constant for all regions in all years. The EIA estimates a conventional combined cycle generation resource entering service in 2016 and operating at a capacity factor of 87 percent carries a annual fixed cost of about 200 $/kW/yr, and a conventional combustion turbine entering service in 2016 operating at a capacity factor of 30% carries an annual cost of 120 $/kW/yr. At 0% capacity factor, the capacity value was estimated to be about 10% of the 30% capacity factor value, or 12 $/kW-yr. The resulting incremental capacity values as a function of capacity factor is shown on Figure 5-5.

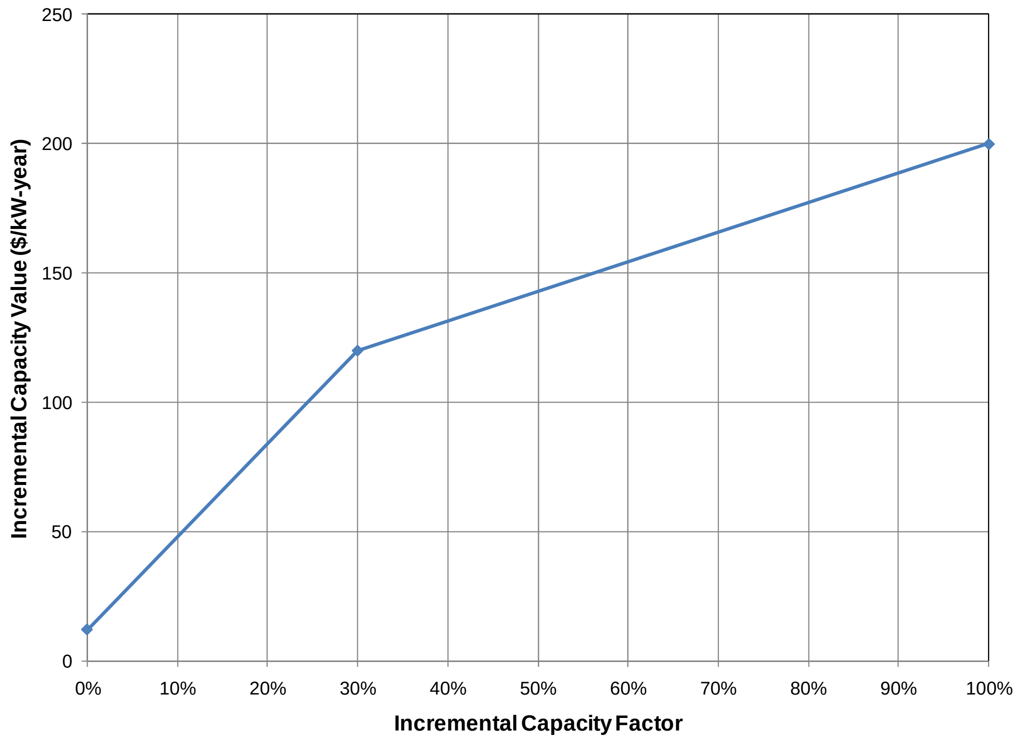

Figure 5-5. Capacity Value as a Function of Incremental Capacity Factor

It should be noted that the useful life of most thermal alternatives is 30 years, rather than the 50 to 100-year life assumed for hydro plants. It is assumed that, should the alternative thermal plant be constructed, it would be replaced by an identical plant at appropriate intervals through the hydro project's life (30, 60, and 90 years). As long as the thermal plant cost increases over this period are limited to those resulting from general inflation, the amortized present value of the fixed costs for the series of identical thermal plants over 100 years (adjusted to remove the effects of general inflation) will be identical to the amortized present value of the initial thermal plant amortized over its 30-year life. As a result, capacity values are normally computed simply on the basis of the initial thermal plant's 30-year life. It is very likely that the replacement plants will not be identical to the initial plant, but it is difficult to predict 30 years in advance if the replacement plant will be more or less expensive (in today's dollars) than the initial plant. Because of the uncertainty about future inflation and because the present value of the future replacement plants is relatively small, basing capacity values on the initial thermal plant's service life is considered to be reasonable (USACE 1985). Therefore, the capacity values shown on Figure 5-3 were assumed to remain constant over the 50-year economic life.

To be allocated economic benefits, the capacity should be dependable capacity. While procedures for determining dependable capacity can vary by region, dependable capacity essentially means that the capacity will be available with a high reliability when needed, at least for short periods of time. Because most of the Reclamation plants have storage reservoirs associated with them, it has been assumed in this planning-level study that the capacity would be available on demand. To the extent that site specific operating limitations restrict the ability to use the additional capacity when needed, the capacity benefits could be reduced. More detailed future feasibility studies could refine the estimate of dependable capacity.

Chapter 6
Capacity Addition Cost Estimates

A cost estimating methodology was needed that would be applicable to potential capacity additions at all 58 existing hydropower sites and which could be developed quickly for five capacity additions at each plant. The Idaho National Engineering and Environmental Laboratory (INEEL) has developed such a methodology under contract to the U.S. Department of Energy (INEEL 2003). A collection of sources of historical hydroelectric plant data was used by INEEL to create cost estimating equations. Costs are not based on site specific conditions at the individual plants, which would be the subject of future studies.

Because it was determined that the various costs correlated with plant capacity, cost estimating equations were developed as a function of installed capacity. The cost estimating equations developed for existing dams with existing hydropower plants were used in this study. These cost estimating equations were also used in a more recent study of potential hydroelectric development at existing Federal facilities (U.S. Department of the Interior, et al, 2007) that is commonly known as the 1834 Study.

The following are the formulas for each cost category, where MW is the additional installed capacity in megawatts (expressed in 2002 dollars):

- Construction cost = $1{,}400{,}000*MW^{0.81}$
- Fish and wildlife mitigation cost = $83{,}000*MW^{0.96}$
- Recreation mitigation cost = $63{,}000*MW^{0.97}$
- Historical and archaeological mitigation cost = $63{,}000*MW^{0.72}$
- Water quality monitoring cost = $70{,}000*MW^{0.44}$
- Fixed annual O&M = $24{,}000*MW^{0.75}$
- Variable annual O&M = $24{,}000*MW^{0.80}$

It is noted that in the 1834 Study, the coefficient for the annual O&M costs is apparently incorrectly shown as 240,000.

Construction costs were adjusted from 2002 dollars to the anticipated online date using the Reclamation construction cost index for powerplants up to 2010 (Reclamation 2010) and the U.S. Army Corps of Engineers civil works construction cost index system (USACE 2010) from 2010 to the assumed online date in 2015. Mitigation costs were escalated to 2015 using the general annual inflation rate of 1.8%. Operation and maintenance costs were escalated at 2.3% per year.

Figure 6-1 provides a graphical summary of the construction and mitigation costs for capacity additions up to 100 MW. Construction and mitigation costs were totaled to form an initial development cost, which was then divided by the installed capacity to form the commonly used index of initial capacity cost in dollars per kilowatt. As shown on Figure 6-1, 10 MW of capacity addition costs about $1,550/kW, while the cost of 100 MW of capacity addition would be reduced to about $1,040/kW.

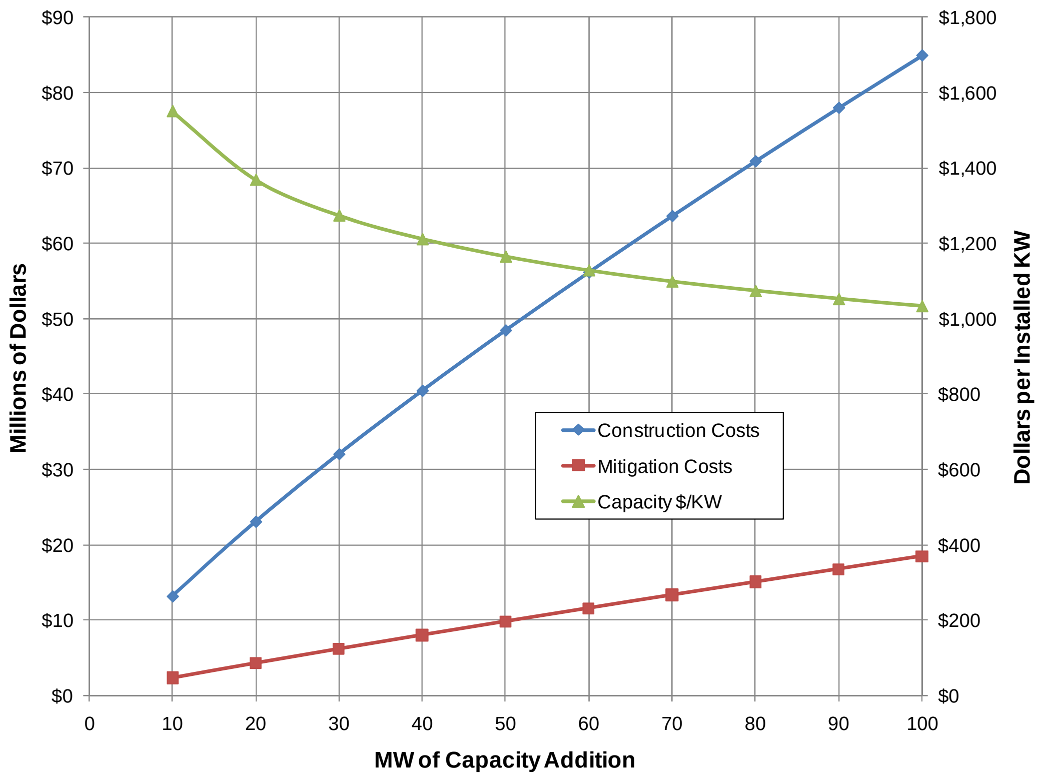

Figure 6-1. Construction, Mitigation, and Capacity Costs as a Function of Added MW

Chapter 7
Environmental and Climate Change Benefits

This chapter provides quantitative and qualitative information related to the environmental and climate change benefits of hydroelectric capacity additions. Environmental and climate change benefits from hydroelectric plants primarily result from the replacement (offset) of fossil fuel generation and its associated GHG emissions, with emission-free hydroelectric generation. Additional environmental benefits can be associated with turbine and runner replacement, which can result in uprating or capacity addition at a hydroelectric plant. In addition to GHG offsets, potential environmental benefits from capacity addition or turbine replacement projects include:

- Offsets of criteria pollutant emissions and other air toxics emissions.
- Elimination of grease contamination to the river by installing greaseless wicket gate bushings when the turbine runners are replaced.
- Improve water quality by increasing dissolved oxygen (DO) levels with the installation of aerating-type turbine runners.

Though environmental benefits have intrinsic value, monetary valuation of these benefits is complicated and currently there is no established, stable, generally accepted market value. In contrast, the quantification of GHG reductions has well established procedures and is therefore used in this project to demonstrate and rank environmental benefits.

Hydropower and Greenhouse Gasses

In the United States (U.S.), carbon dioxide accounts for 85 percent (%) of GHG emissions, with about 34% of the carbon dioxide emissions originating from electricity generation, which is more than from any other single source. Energy-related GHG emissions, mainly from fossil fuel combustion are projected to rise by over 50% by 2030 (IPCC 2007b). This makes reductions of GHG from electricity generation an imperative.

In 2004, hydroelectric systems provided 16% of global electricity and 90% of global renewable energy (IPCC 2007b). In the United States, hydropower accounted for nearly 9% of the U.S. total electric generating capacity (EPRI 2007) and about 7% of the annual electric energy output (EIA 2008). Existing conventional hydropower generation represents 75% of the U.S. renewable energy generation, averaging about 270,000 GWh per year (EPRI 2007). In the United States in 2006, hydropower capacity was about 96,000 MW, split between about 75,000 MW of conventional capacity and 21,000 MW of pumped storage capacity. The 75,000 MW of conventional hydropower capacity was split almost equally between federal projects (~37,500 MW) and non-federal projects that are subject to FERC jurisdiction over licensing and regulatory structure (Hall and Reeves 2006). This means that federal hydropower projects provide a significant opportunity for GHG reductions.

Between 1980 and 2006, average annual hydroelectric energy generation in the United States remained almost constant, while thermal electric energy generation increased by about 70% (EIA 2008). Therefore, with consideration given to GHG offsets available from green hydropower production, incremental hydropower generation increases should be implemented when justified, and existing hydropower capacity should be maintained and rehabilitated as needed.

Opportunities for Climate Change Benefits

GHG reductions that will result from hydroelectric capacity additions or investments are accounted for in three different ways in this study:

- Capacity additions result in increased hydroelectric energy output by increasing the hydraulic capacity of the turbines and generating with flow that would be otherwise spilled and not flow through a turbine.

- Turbine runner replacement will result in improvement of the runner condition (elimination of deterioration and surface irregularities) that improves efficiency and increases energy generation. Turbine runner replacement may also result in a modern runner shape that is inherently more efficient (1.5%) than the older runner was in new condition.

- Planned turbine replacements will reduce the risk of longer unplanned outage durations and therefore result in reduced generation losses. Depending on the system or type of equipment, outage durations can vary significantly. A one year incremental outage of one unit at each plant was used as an index value to account for the reduced generation losses and GHG offsets that could potentially result from planned turbine replacements.

GHG Reduction Quantification

Environmental benefits in the form of GHG emission reductions will be achieved though incremental energy increases due to improved efficiency, increased hydraulic capacity, and reduced outages. Hydropower generation increases resulting from these equipment improvements were determined for each plant on an annual average basis. The annual average incremental generation increase at the plant was used to calculate annual average GHG reductions.

GHG reductions are quantified in terms of metric tons of carbon dioxide (CO_2) or carbon dioxide equivalents (CO_2e). In this evaluation of hydropower capacity addition projects, CO_2e incorporates the global warming potential of methane (CH_4) and nitrous oxide (N_2O), the other two primary GHG emissions that result from burning fossil fuels. Table 7-1 shows the relative 100-year global warming potential values (per lb CO_2) for CO_2, CH_4 and N_2O that are based on the Intergovernmental Panel on Climate Change's Second Assessment Report (IPCC, 2007a).

Table 7-1. 100-Year Global Warming Potential Values

	Greenhouse Gas		
	Carbon Dioxide (CO_2)	Methane (CH_4)	Nitrous Oxide (N_2O)
IPCC Second Assesment Report Values	1	21	310

GHG reductions were estimated using GHG emission rates based on the regional electricity generation resource mix and the 100-year global warming potential values for CO_2, CH_4 and N_2O to determine the total CO_2e offsets. The values were taken from the U.S. Environmental Protection Agency's (USEPA) Office of Atmospheric Programs' eGRID2007 (Version 1.1) database (USEPA 2008). eGrid (Emissions & Generation Resource Integrated Database) is an inventory of environmental attributes of electric power systems in the U.S., and was compiled based on information from USEPA, the Energy Information Administration, FERC, and the North American Electric Reliability Corporation (NERC) (USEPA, 2008). The regional GHG emission rates for each plant were determined based on the eGrid subregion, shown in Figure 7-1.

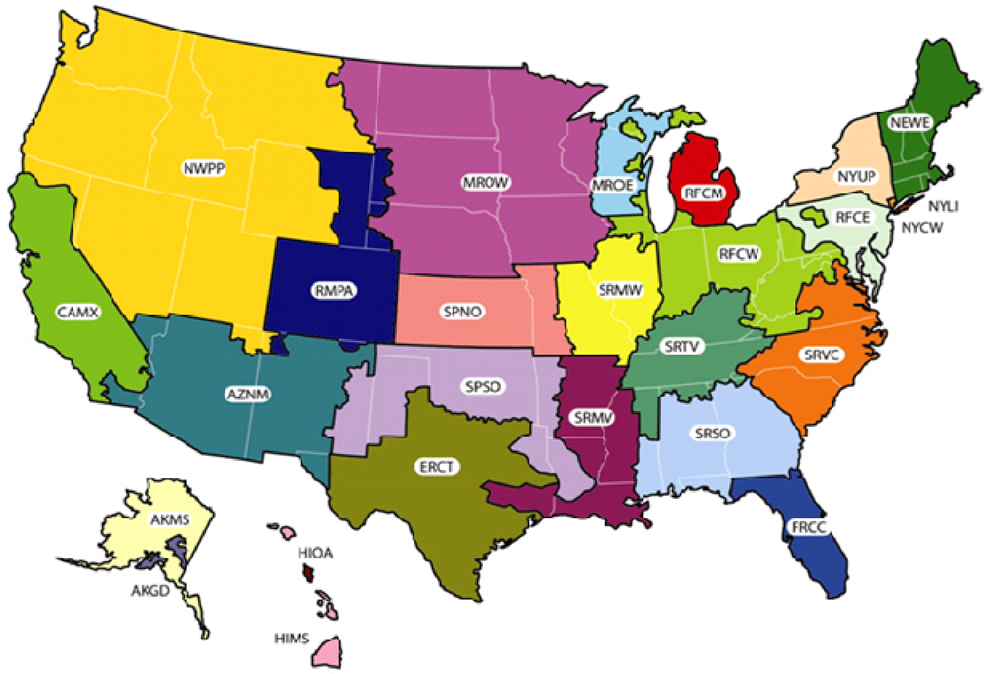

Figure 7-1. eGrid Subregions

Annual GHG output emission rates, based on the existing generation mix in each geographic area, are shown on Table 7-2 in pounds per megawatt-hour (lb/MWh) for CO_2, CH_4 and N_2O, for the regions encompassing the locations of the 58 plants. The annual output emission rates are used to calculate GHG reductions from baseload, or off-peak, generation, and the non-baseload emission rates are used to calculate GHG reductions from non-baseload, or on-peak, generation.

Table 7-2. Year 2005 GHG Annual Output Emission Rates

eGRID subregion acronym	eGRID Subregion Name	Annual output emission rates			Annual non-baseload output emission rates		
		Carbon dioxide (lb/MWh)	Methane (lb/MWh)	Nitrous oxide (lb/MWh)	Carbon dioxide (lb/MWh)	Methane (lb/MWh)	Nitrous oxide (lb/MWh)
AZNM	WECC Southwest	1311.05	0.0175	0.0179	1201.44	0.0208	0.0085
CAMX	WECC California	724.12	0.0302	0.0081	1083.02	0.0392	0.0056
NWPP	WECC Northwest	902.24	0.0191	0.0149	1333.64	0.0493	0.0187
RMPA	WECC Rockies	1883.08	0.0229	0.0288	1617.71	0.0224	0.0201

GHG reductions are quantified in terms of metric tons of CO_2e offset. The GHG offsets are based on the megawatt-hours of incremental generation that result from hydroelectric capacity increases, efficiency increases, or reduced outages. Efficiency increases from turbine runner replacement were based on the expected degradation of the turbine runners as a function of age plus increase due to modern design if the runners were older than 15 years. Because outage durations vary depending on the system or equipment affected, GHG offsets from outages are given as an index value based on an assumed one year incremental outage of one unit at each plant.

Greenhouse Gas Equivalents

The quantification of GHG offsets in metric tons of a gas and carbon dioxide equivalents are new terms for most people. Another way GHG reductions can be presented is in terms of CO_2e equivalents, which describe these abstract concepts in everyday terms. While it may be difficult to picture how much a metric ton of gas is, it is easier to understand that one metric ton of CO_2e is equivalent to the CO_2 emissions from consuming 114 gallons of gasoline (USEPA 2009). In comparison to generation from fossil fuel sources, 100,000 MWh of hydropower generation would offset:

- 71,816 metric tons of carbon dioxide equivalent (CO_2e)
- 13,732 passenger vehicles taken off the road/year
- 8,078,332 gallons of gasoline consumed
- 167,015 barrels of oil consumed
- 8,716 homes electricity use for 1 year
- 6,112 homes total energy use for 1 year
- 0.02 coal fired power plant for 1 year

Chapter 8
Plant Data Ratings

As requested by Reclamation, a plant data rating was developed to provide a measure of the quality and completeness of the data input to the energy model. Data quality ratings were input and displayed in the energy model, but were not used to modify the results. Ratings are unrelated to plant condition or operation.

Input data was given a score on a four point scale based on the descriptions provided below:

Rating 1 – The data was essentially complete with no significant omissions. Daily total outflow and head data, in the form of daily headwater elevations and daily tailwater elevations or a tailwater rating curve, were provided for at least 10 years. Where some parameter data was missing, relatively reliable fallback data sources were provided by Reclamation. Actual generation, either daily or monthly, was provided for the same period as the flow data.

Rating 2 – The data was mostly complete with some significant omissions. Significant omissions include data sets for plants with less than 10 years of daily total outflow and head data; at a low head plants, data sets that included daily reservoir elevations without a tailwater rating curve, and either a constant tailwater or an estimated tailwater rating curve had to be used; data sets that did not include required releases that are unavailable for generation increases, etc. Some actual generation, either daily or monthly, was provided.

Rating 3 – The data had major shortcomings. Major shortcomings include data sets for plants that had only monthly total outflow and head data; plants that only provided generation outflow; plants with less than 5 years of daily total outflow and head data, etc. Several parameters may have been missing for which no reliable fallback data sources were available. No generation data were provided.

Rating 4 – The data was insufficient to perform the energy model analysis. An example would be a plant where no flow data or no head data of any type was provided by Reclamation.

Table 8-1 provides a summary of the plant data ratings.

Table 8-1. Plant Data Ratings Summary

Region	Number of Plants with each Rating			
	1	**2**	**3**	**4**
Great Plains	8	5	8	0
Lower Colorado	3	0	0	0
Mid-Pacific	9	1	1	0
Pacific Northwest	5	2	3	0
Upper Colorado	0	8	4	0
Total Plants	25	16	16	0

Table 8-2 provides the data ratings for the individual plants.

Table 8-2. Individual Plant Data Ratings

Plant	Region	Data Quality Rating
Alcova	Great Plains	1
Anderson Ranch	Pacific Northwest	1
Big Thompson	Great Plains	2
Black Canyon	Pacific Northwest	1
Blue Mesa	Upper Colorado	2
Boise Diversion	Pacific Northwest	3
Boysen	Great Plains	1
Buffalo Bill	Great Plains	3
Canyon Ferry	Great Plains	1
Chandler	Pacific Northwest	3
Crystal	Upper Colorado	2
Davis	Lower Colorado	1
Deer Creek	Upper Colorado	2
Elephant Butte	Upper Colorado	3
Estes	Great Plains	3
Flaming Gorge	Upper Colorado	2
Flatiron	Great Plains	3
Folsom	Mid-Pacific	1
Fontenelle	Upper Colorado	2
Fremont Canyon	Great Plains	3
Glen Canyon	Upper Colorado	2
Glendo	Great Plains	1
Grand Coulee	Pacific Northwest	1
Green Mountain	Great Plains	2
Green Springs	Pacific Northwest	2
Guernsey	Great Plains	1
Heart Mountain	Great Plains	3
Hoover	Lower Colorado	1
Hungry Horse	Pacific Northwest	2
Judge Francis Carr	Mid-Pacific	3
Keswick	Mid-Pacific	1
Kortes	Great Plains	1
Lower Molina	Upper Colorado	3
Marys Lake	Great Plains	2
McPhee	Upper Colorado	2
Minidoka	Pacific Northwest	1
Morrow Point	Upper Colorado	2
Mount Elbert	Great Plains	3
New Melones	Mid-Pacific	1
Nimbus	Mid-Pacific	1
O'Neill	Mid-Pacific	1
Palisades	Pacific Northwest	1
Parker	Lower Colorado	1
Pilot Butte	Great Plains	2
Pole Hill	Great Plains	2
Roza	Pacific Northwest	3
San Luis	Mid-Pacific	1
Seminoe	Great Plains	1
Shasta	Mid-Pacific	1
Shoshone	Great Plains	3
Spirit Mountain	Great Plains	3
Spring Creek	Mid-Pacific	1
Stampede	Mid-Pacific	2
Towaoc	Upper Colorado	3
Trinity	Mid-Pacific	1
Upper Molina	Upper Colorado	3
Yellowtail	Great Plains	1

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Chapter 9
Summary of Results

The results from the energy model include the economic calculations, the incremental generation from the existing units due to capacity increases or efficiency gains, and the avoided generation loss from outages. These results are used to determine the GHG offsets. The results for the capacity addition opportunities, additional generation and GHG offsets are shown by region for each of the plants and the top potential capacity increase opportunities are discussed in this chapter.

Capacity Additions

A brief review of the steps in the determination of capacity addition results is summarized as follows:

- Based on the plant nameplate capacity, determine the 10%, 20%, 30%, 40%, and 50% capacity additions in MW
- From the capacity additions in MW, determine the corresponding hydraulic capacity increases in cubic feet per second (cfs)
- For each of the hydraulic capacity increases, determine the incremental energy with PLEESM (Chapter 3 of this report)
- Determine the energy benefits from the energy values ($/MWh) as presented in Chapter 5 and the average monthly incremental energy (MWh)
- From the incremental energy increases, determine the capacity factor
- Determine the incremental capacity value ($/kW-yr) from the capacity factor and Figure 5-5
- Determine the capacity benefits from the incremental capacity value ($/kW-yr)and the capacity additions (kW)
- Develop the total costs as presented in Chapter 6 of this report
- Using the economic parameters and methodology presented in Chapter 4, determine the present values of the total costs and the total benefits (energy plus capacity)
- Determine the NPV, which is the present value of benefits minus present value of costs; and the BCR, which is the present value of benefits minus the present value of costs.

- From the five capacity addition increments, select the capacity addition with the maximum BCR and the one with the maximum NPV, which can result in the selection of two different capacity increments.

It must be emphasized that selecting a capacity addition with the maximum NPV or BCR is not necessarily an indication of economic viability. Only capacity additions with benefit to cost ratios greater than 1.00 and positive net present values provide indications of economic feasibility.

For plants that have zero or negligible incremental energy associated with the capacity additions, the BCR values will maximize at the largest (50%) capacity addition because the cost per installed kilowatt decreases with size (Fig. 6-1) and the capacity benefit per installed kilowatt is constant when the capacity factor is zero (Fig. 5-5). For example, Grand Coulee has its maximum BCR of 0.27 at the 50% capacity increase of 3,247.5 MW, which should not be interpreted to mean that the recommended capacity addition is over 3,000 MW. The bottom line message for Grand Coulee (and other plants with similar results) would be that no capacity addition shows economic feasibility based on the methodologies employed in this report.

The capacity addition results are shown by region in Tables 9-1 through 9-5 for each of the five Reclamation regions and are summarized below. The plants are ranked in each region based on the maximum BCR from the five capacity addition increments included in the analysis. For each plant, the existing installed capacity, maximum BCR and NPV, the capacity increase increment associated with the maximum BCR and NPV are shown in the table. The capacity increase and the incremental capacity factor associated with the maximum BCR are also shown.

Mid-Pacific Region

Of the 11 plants in the Mid-Pacific region, the only plant with have both BCRs equal to or greater than one and positive NPVs is Nimbus (Table 9-1). The maximum BCR for Nimbus of 1.39 occurs at a capacity increase of 20% over the existing installed capacity, which corresponds to a 2.7 MW capacity increase. The incremental capacity factor for a 2.7 MW capacity increase at Nimbus is 26% indicating that the potential incremental generation is about a quarter of the generation that could be obtained if the additional capacity was run continuously at full output. Since the remaining plants in the Mid-Pacific region have BCRs less than 1.0 and negative NPVs, capacity additions at these plants would not be economically beneficial.

A Lease of Power Privilege Agreement for the Lewiston Hydroelectric Project (Agreement) was signed in June 2009 between Reclamation and the Trinity Public Utilities District (TPUD). The Agreement calls for complete replacement of the existing 350 kW hydroelectric unit with a new unit capable of generating up to 2,000 kW. The TPUD generation share from the new unit would be all generation in excess of that for the 350 kW unit if it operated at a

90.1% capacity factor. Because the Lewiston capacity addition will be (or has been) determined by TPUD within the limits of the Agreement, it would not be productive to include Lewiston in the current studies. Therefore, no results are presented for Lewiston.

Table 9-1. Capacity Addition Results - Mid-Pacific Region

Rank [1]	Plant	Existing Installed Capacity (MW)	Maximum BCR Percent Increase	Maximum NPV Percent Increase	Capacity Increase (MW)	Incremental Generation from Capacity Addition [2] (MWh/yr)	Incremental Capacity Factor	Maximum BCR	Maximum NPV ($M)
1	Nimbus	13.5	20%	50%	2.7	6,104	26%	1.39	$5.8
2	Folsom	207	30%	20%	62	32,607	6.0%	0.97	-$2.3
3	Shasta	714	30%	10%	214	73,426	3.9%	0.86	-$23.8
4	Stampede	3.65	30%	10%	1.1	1,669	17%	0.85	-$0.3
5	Keswick	117	40%	10%	47	26,278	6.4%	0.66	-$10.1
6	Trinity	140	20%	10%	28	17,625	7.2%	0.57	-$13.7
7	Judge Francis Carr	154	10%	10%	15	4,476	3.3%	0.45	-$17.0
8	Spring Creek	180	20%	10%	36	12,180	3.9%	0.21	-$28.0
9	San Luis [3]	424	50%	10%	212	5,289	0.3%	0.16	-$61.7
10	New Melones	382	50%	10%	191	7,830	0.5%	0.16	-$56.9
11	O'Neill	25	10%	10%	2.5	251	1.1%	0.12	-$6.5

Notes

[1] Plants are ranked based on the capacity addition increment with the highest BCR for each plant .

[2] Incremental generation shown is for the capacity addition with the highest BCR.

[3] Installed capacity of 424 MW for San Luis includes the Federal and CA shares. The Federal share is 202 MW.

BCR - Benefit to Cost Ratio

NPV - Net Present Value

Upper Colorado Region

Of the 12 plants in the Upper Colorado region, two plants, Deer Creek and Crystal, both have BCRs equal to or greater than one and positive NPVs (Table 9-2). The maximum BCR for Deer Creek of 1.04 occurs at a capacity increase of 10% over the existing installed capacity, which corresponds to a 495 kW capacity increase. The incremental capacity factor for the 495 kW capacity increase at Deer Creek is 24%. The maximum BCR for Crystal of 1.00 occurs at a capacity increase of 30% over the existing installed capacity which corresponds to a 9.5 MW capacity increase. The incremental capacity factor for the 9.5 MW capacity increase at Crystal is 13%. The remaining plants in the Upper Colorado region have BCRs less than or equal to one and negative NPVs, or no NPV in the case of McPhee; thus, capacity additions at these plants would not be economically beneficial.

Table 9-2. Capacity Addition Results - Upper Colorado Region

Rank [1]	Plant	Existing Installed Capacity (MW)	Maximum BCR Percent Increase	Maximum NPV Percent Increase	Capacity Increase (MW)	Incremental Generation from Capacity Addition [2] (MWh/yr)	Incremental Capacity Factor	Maximum BCR	Maximum NPV ($M)
1	Deer Creek	5.0	10%	20%	0.5	1,023	24%	1.04	$0.1
2	Crystal	32	30%	30%	9.5	10,950	13%	1.00	$0.1
3	McPhee	1.3	10%	10%	0.1	413	37%	1.00	$0.0
4	Fontenelle	10	50%	10%	5.0	4,774	11%	0.57	-$1.9
5	Glen Canyon	1,320	30%	10%	396	71,082	2.0%	0.51	-$103
6	Towaoc	11	10%	10%	1.1	1,120	11%	0.41	-$2.3
7	Flaming Gorge	152	50%	10%	76	13,495	2.0%	0.35	-$20.2
8	Blue Mesa	86	40%	10%	35	3,219	1.1%	0.23	-$15.4
9	Morrow Point	173	50%	10%	87	10,279	1.4%	0.20	-$28.4
10	Elephant Butte	28	10%	10%	2.8	357	1.5%	0.15	-$6.8
11	Lower Molina	4.9	50%	10%	2.4	133	0.6%	0.10	-$1.8
12	Upper Molina	8.6	50%	10%	4.3	8	0%	0.08	-$3.0

Notes
[1] Plants are ranked based on the capacity addition increment with the highest BCR for each plant .
[2] Incremental generation shown is for the capacity addition with the highest BCR.
BCR - Benefit to Cost Ratio
NPV - Net Present Value

Great Plains Region

Of the 21 plants in the Great Plains region, three plants, Shoshone, Canyon Ferry, and Guernsey, have both BCRs equal to or greater than one and positive NPVs (Table 9-3). The maximum BCR for Shoshone of 3.50 occurs at a capacity increase of 50% over the existing installed capacity, which corresponds to a 1.5 MW capacity increase. The incremental capacity factor for the 1.5 MW capacity increase at Shoshone is 94%. However, the simulated generation for Shoshone was in the range of 20 - 25% higher than the actual recorded generation, which indicates a moderate degree of uncertainty in the results for this plant.

The maximum BCR for Canyon Ferry of 1.53 occurs at a capacity increase of 10% over the existing installed capacity which corresponds to a 5.0 MW capacity increase and an incremental capacity factor of 40%. The maximum BCR for Guernsey of 1.52 occurs at a capacity increase of 50% over the existing installed capacity which corresponds to a 3.2 MW capacity increase and an incremental capacity factor at Guernsey of 32%. The remaining plants in the Great Plains region have BCRs less than one and negative NPVs; thus, capacity additions at these plants would not be economically beneficial.

Table 9-3. Capacity Addition Results - Great Plains Region

Rank [1]	Plant	Existing Installed Capacity (MW)	Maximum BCR Percent Increase	Maximum NPV Percent Increase	Capacity Increase (MW)	Incremental Generation from Capacity Addition [2] (MWh/yr)	Incremental Capacity Factor	Maximum BCR	Maximum NPV ($M)
1	Shoshone	3.0	50%	50%	1.5	12,347	94%	3.50	$12.2
2	Canyon Ferry	50	10%	40%	5.0	17,576	40%	1.53	$13.4
3	Guernsey	6.4	50%	50%	3.2	8,887	32%	1.52	$4.6
4	Pilot Butte	1.6	50%	50%	0.8	1,800	26%	0.96	-$0.1
5	Buffalo Bill	18	10%	10%	1.8	3,985	25%	0.81	-$1.1
6	Glendo	38	20%	10%	7.6	8,726	13%	0.73	-$2.8
7	Fremont Canyon	67	10%	10%	6.7	9,238	16%	0.62	-$6.0
8	Boysen	15	40%	10%	6.0	5,322	10%	0.56	-$2.2
9	Kortes	36	50%	10%	18	4,594	2.9%	0.33	-$6.9
10	Big Thompson	4.5	10%	10%	0.5	494	13%	0.30	-$1.3
11	Alcova	41	20%	10%	8.3	2,003	2.8%	0.27	-$8.0
12	Seminoe	52	30%	10%	16	5,592	4.1%	0.27	-$9.9
13	Yellowtail	250	30%	10%	75	8,526	1.3%	0.27	-$34.8
14	Green Mountain	26	50%	10%	13	2,065	1.8%	0.23	-$6.0
15	Mount Elbert	200	50%	10%	100	3,965	0.5%	0.14	-$34.4
16	Flatiron [3]	94.5	50%	10%	41	4,153	1.2%	0.12	-$17.0
17	Estes	45	50%	10%	23	1,854	0.9%	0.11	-$10.7
18	Pole Hill	38	50%	10%	19	3,173	1.9%	0.10	-$9.5
19	Heart Mountain	5.0	50%	10%	2.5	481	2.2%	0.09	-$1.9
20	Marys Lake	8.1	50%	10%	4.1	687	1.9%	0.08	-$2.8
21	Spirit Mountain	4.5	50%	10%	2.3	220	1.1%	0.07	-$1.8

Notes
[1] Plants are ranked based on the capacity addition increment with the highest BCR for each plant .
[2] Incremental generation shown is for the capacity addition with the highest BCR.
[3] Installed capacity at Flatiron is 94.5 MW. Only Units 1 and 2 (81.3 MW) were included in the modeling.
BCR - Benefit to Cost Ratio
NPV - Net Present Value

Pacific Northwest Region

Of the ten plants in the Pacific Northwest region, four plants, Black Canyon, Boise Diversion, Palisades, and Minidoka, have both BCRs equal to or greater than one and positive NPVs (Table 9-4). The maximum BCR for Black Canyon of 2.52 occurs at a capacity increase of 50% over the existing installed capacity, which corresponds to a 5.1 MW capacity increase and an incremental capacity factor of 43%. The maximum BCR for Boise Diversion of 2.48 occurs at a capacity increase of 40% over the existing installed capacity, which corresponds to a 1.4 MW capacity increase and an incremental capacity factor at Boise Diversion of 52%. The simulated generation for Boise Diversion was in the range of 20 - 25% higher than the actual recorded generation, which indicates a moderate degree of uncertainty in the results for this plant.

The maximum BCR for Palisades of 2.28 occurs at a capacity increase of 20% over the existing installed capacity which corresponds to a 35 MW capacity increase. The incremental capacity factor for the 35 MW capacity increase at Palisades is 24%. The maximum BCR for Minidoka of 1.21 occurs at a capacity increase of 10% over the existing installed capacity which corresponds to a 2.8 MW capacity increase. The incremental capacity factor for the 2.8 MW capacity increase at Minidoka is 13%. The remaining plants in the Pacific Northwest region have BCRs less than one and negative NPVs; thus, capacity additions at these plants would not be economically beneficial.

Table 9-4. Capacity Addition Results - Pacific Northwest Region

Rank [1]	Plant	Existing Installed Capacity (MW)	Maximum BCR Percent Increase	Maximum NPV Percent Increase	Capacity Increase (MW)	Incremental Generation from Capacity Addition [2] (MWh/yr)	Incremental Capacity Factor	Maximum BCR	Maximum NPV ($M)
1	Black Canyon	10	50%	50%	5.1	19,026	43%	2.52	$19.6
2	Boise Diversion	3.5	40%	50%	1.4	6,231	52%	2.48	$7.8
3	Palisades	177	20%	50%	35	72,778	24%	2.28	$123
4	Minidoka	28	10%	20%	2.8	3,098	13%	1.21	$2.6
5	Anderson Ranch	40	50%	10%	20	19,805	11%	0.91	-$3.2
6	Chandler	12	10%	10%	1.2	594	5.6%	0.32	-$2.8
7	Grand Coulee	6,495	50%	10%	3,248	141	0.0%	0.27	-$510
8	Hungry Horse	428	50%	10%	214	19,275	1.0%	0.19	-$59.9
9	Green Springs	17	50%	10%	8.6	0.0	0.0%	0.09	-$5.1
10	Roza	13	50%	10%	6.5	1,062	1.9%	0.08	-$4.1

Notes
[1] Plants are ranked based on the capacity addition increment with the highest BCR for each plant .
[2] Incremental generation shown is for the capacity addition with the highest BCR.
BCR - Benefit to Cost Ratio
NPV - Net Present Value

Lower Colorado Region

None of the plants in the Lower Colorado regionhave both BCRs equal to or greater than one and positive NPVs (Table 9-5). Therefore, capacity additions at the plants in the Lower Colorado region would not be economically beneficial.

Table 9-5. Capacity Addition Results - Lower Colorado Region

Rank [1]	Plant	Existing Installed Capacity (MW)	Maximum BCR Percent Increase	Maximum NPV Percent Increase	Capacity Increase (MW)	Incremental Generation from Capacity Addition [2] (MWh/yr)	Incremental Capacity Factor	Maximum BCR	Maximum NPV ($M)
1	Davis	255	10%	10%	26	15,784	7.1%	0.76	-$11.1
3	Parker	120	20%	10%	24	15,049	7.2%	0.76	-$7.1
2	Hoover	2,079	50%	10%	1,039	0	0%	0.22	-$212

Notes
[1] Plants are ranked based on the capacity addition increment with the highest BCR for each plant .
[2] Incremental generation shown is for the capacity addition with the highest BCR.
BCR - Benefit to Cost Ratio
NPV - Net Present Value

Summary of Capacity Addition Results

Of the 58 plants included in the assessment, ten plants have both BCRs equal to or greater than one and positive NPVs. These ten opportunities for capacity additions based on BCRs are summarized in Table 9-6. Three of these plants are located in the Great Plains region, four plants are located in the Pacific Northwest region, two plants are located in the Upper Colorado region, and one plant is located in the Mid-Pacific region. The plant with the highest BCR of 3.50 is Shoshone in the Great Plains region. Shoshone also has the highest incremental capacity factor of 94%. The plant with the largest potential capacity increase of 35 MW is Palisades in the Pacific Northwest region which ranked fourth overall based on BCR.

Table 9-6. Summary - Capacity Addition Opportunities Ranked by BCR

Rank [1]	Plant	Region	Existing Installed Capacity (MW)	Maximum BCR Percent Increase	Maximum NPV Percent Increase	Maximum BCR Capacity Increase (MW)	Incremental Generation from Capacity Addition [2] (MWh/yr)	Incremental Capacity Factor	Maximum BCR	Maximum NPV ($M)
1	Shoshone	Great Plains	3.0	50%	50%	1.5	12,347	94%	3.50	$12.2
2	Black Canyon	Pacific Northwest	10	50%	50%	5.1	19,026	43%	2.52	$19.6
3	Boise Diversion	Pacific Northwest	3.5	40%	50%	1.4	6,231	52%	2.48	$7.8
4	Palisades	Pacific Northwest	177	20%	50%	35	72,778	24%	2.28	$123
5	Canyon Ferry	Great Plains	50	10%	40%	5.0	17,576	40%	1.53	$13.4
6	Guernsey	Great Plains	6.4	50%	50%	3.2	8,887	32%	1.52	$4.6
7	Nimbus	Mid-Pacific	13.5	20%	50%	2.7	6,104	26%	1.39	$5.8
8	Minidoka	Pacific Northwest	28	10%	20%	2.8	3,098	13%	1.21	$2.6
9	Deer Creek	Upper Colorado	5.0	10%	20%	0.5	1,023	24%	1.04	$0.1
10	Crystal	Upper Colorado	31.5	30%	30%	9.5	10,950	13%	1.00	$0.1

Notes
[1] Plants are ranked based on the capacity addition increment with the highest BCR for each plant .
[2] Incremental generation shown is for the capacity addition with the highest BCR.
BCR - Benefit to Cost Ratio
NPV - Net Present Value

The opportunities for capacity additions based on NPV are shown in Table 9-7. The same ten plants that represented the top opportunities for capacity additions based on BCR are the plants with the top opportunities for capacity additions based on NPV, but with a shift in the ranking order. Palisades has the highest NPV for a capacity addition of $123 million which corresponds to a 50% increase over the existing installed capacity and an actual increase of 88 MW. However, the incremental capacity factor for the 88 MW capacity increase at Palisades is only 17%. At an 88 MW capacity increase, Palisades has the largest capacity increase potential of all the plants with a positive NPV. The plant with the highest incremental capacity factor based on NPV of 94% is Shoshone with a capacity increase 50% greater than its existing capacity, or 1.5 MW, which is unchanged from the BCR rankings.

Table 9-7. Summary - Capacity Addition Opportunities Ranked by NPV

Rank [1]	Plant	Region	Existing Installed Capacity (MW)	Maximum BCR Percent Increase	Maximum NPV Percent Increase	Maximum NPV Capacity Increase (MW)	Incremental Generation from Capacity Addition [2] (MWh/yr)	Incremental Capacity Factor	Maximum BCR	Maximum NPV ($M)
1	Palisades	Pacific Northwest	177	20%	50%	88	129,245	17%	2.28	$123
2	Black Canyon	Pacific Northwest	10	50%	50%	5.1	19,026	43%	2.52	$19.6
3	Canyon Ferry	Great Plains	50	10%	40%	20	35,538	20%	1.53	$13.4
4	Shoshone	Great Plains	3.0	50%	50%	1.5	12,347	94%	3.50	$12.2
5	Boise Diversion	Pacific Northwest	3.5	40%	50%	1.7	7,234	48%	2.48	$7.8
6	Nimbus	Mid-Pacific	14	20%	50%	6.8	11,041	19%	1.39	$5.8
7	Guernsey	Great Plains	6.4	50%	50%	3.2	8,887	32%	1.52	$4.6
8	Minidoka	Pacific Northwest	27.7	10%	20%	5.5	6,595	14%	1.21	$2.6
9	Deer Creek	Upper Colorado	5.0	10%	20%	1.0	1,816	21%	1.04	$0.1
10	Crystal	Upper Colorado	32	30%	30%	9.5	10,950	13%	1.00	$0.1

Notes
[1] Plants are ranked based on the capacity addition increment with the highest NPV for each plant .
[2] Incremental generation shown is for the capacity addition with the highest BCR.
BCR - Benefit to Cost Ratio
NPV - Net Present Value

Efficiency Gains

Additional generation from efficiency improvements can be gained in two ways. These are by rehabilitating the turbine to improve its condition such that it operates similar to a new turbine of the original vintage in its original condition, or by replacing an older turbine runner and appurtenant parts with new components of modern design. The incremental generation from efficiency improvements shown in the results tables is the potential additional generation based on both the generation gain from the efficiency deterioration of the existing turbine due to its age and the generation gain from replacing the existing turbine with a new, modern turbine design. Turbines that have been replaced within the past 15 years were assumed to have been replaced with a modern design at that time and thus would not achieve the 1.5% efficiency increase. The age of the turbine was used to determine the efficiency deterioration up to a maximum of 5%, but this particular study did not consider the actual condition of the turbine in estimating performance degradation. The condition will be incorporated in the upcoming Asset Investment Planning (AIP) program and the potential additional generation from turbine upgrades will be refined in the AIP tool.

Where results in the tables show incremental generation increases from efficiency improvements of less than about 2%, it is an indication that improvements have been made in recent years. Where efficiency gains of at least 3% can be made, this represents a potential opportunity.

Costs and economic benefits were not assigned to the efficiency gains in this study. A cost/benefit analysis was not performed for potential efficiency gains because this more detailed level of analysis is performed in the AIP program. .

The efficiency gain results are shown by region in Tables 9-8 through 9-12 for each of the five Reclamation regions and summarized below. The plants are ranked in each region based on the maximum BCR from the five capacity addition increments included in the analysis. For each plant, the existing installed capacity, the average annual existing generation from the energy model simulation and the potential incremental are shown in the table. The generation percent increase over the simulated average annual existing generation is also shown. The energy model simulated existing generation was used because it provides a more uniform long-term average for generation from the current existing installed capacity among the 58 plants than recorded generation, which has been subject shifts from upgrades at various points in time for the 58 plants.

Mid-Pacific Region

The plant with the highest potential incremental generation increase from efficiency improvements in the Mid-Pacific region is Spring Creek with a gain of 36,681 MWh/yr (Table 9-8). The additional generation at Spring Creek corresponds to a 6.2% increase over its existing annual generation. The plants with the highest percent increases in generation over their existing annual generation are Nimbus, San Luis, and O'Neill with potential increases of 4,671 MWh/yr, 20,490 MWh/yr, and 371 MWh/yr, respectively. The generation increases for each of these plants corresponds to a 6.7% increase over their existing annual generation. The Judge Francis Carr plant shows a zero efficiency improvement because the turbine replacement in-service date was within the past two years.

Table 9-8. Efficiency Gain Results - Mid-Pacific Region

Plant	Installed Capacity (MW)	Annual Average Existing Generation (MWh/yr)	Incremental Generation from Efficiency Improvements (MWh/yr)	
			(MWh/yr)	(%)
Nimbus	13.5	69,746	4,671	6.7
Folsom	207	627,943	14,127	2.2
Shasta	714	2,181,077	22,831	1.0
Stampede	3.65	12,915	761	5.9
Keswick	117	461,014	25,762	5.6
Trinity	140	517,251	31,209	6.0
Judge Francis Carr	154	486,896	0	0.0
Spring Creek	180	590,037	36,681	6.2
San Luis [1]	424	304,679	20,490	6.7
New Melones	382	470,677	29,916	6.4
O'Neill	25	5,503	371	6.7

Notes
[1] Installed capacity of 424 MW for San Luis includes the Federal and CA shares. The Federal share is 202 MW.

Upper Colorado Region

The plant with the highest potential incremental generation increase from efficiency improvements in the Upper Colorado region is Glen Canyon with a gain of 38,055 MWh/yr (Table 9-9). The additional generation at Glen Canyon corresponds to a 0.8% increase over its existing annual generation. The plant with the highest percent increase in generation over its existing annual generation is Fontenelle with a potential increase of 6.7% which corresponds to an additional 3,722 MWh/yr. Deer Creek and Crystal, the two plants with BCRs greater than one in the Upper Colorado region, have potential generation increases from efficiency improvements of 391 MWh/yr and 3,386 MWh/yr, respectively,

Table 9-9. Efficiency Gain Results - Upper Colorado Region

Plant	Installed Capacity	Annual Average Existing Generation	Incremental Generation from Efficiency Improvements	
	(MW)	(MWh/yr)	(MWh/yr)	(%)
Deer Creek	5.0	26,968	391	1.4
Crystal	32	187,173	3,386	1.8
McPhee	1.3	5,679	301	5.3
Fontenelle	10	55,444	3,722	6.7
Glen Canyon	1,320	4,982,479	38,055	0.8
Towaoc	11	19,381	1,014	5.2
Flaming Gorge	152	509,422	3,891	0.8
Blue Mesa	86	265,164	8,673	3.3
Morrow Point	173	363,625	19,421	5.3
Elephant Butte	28	116,635	2,374	2.0
Lower Molina	4.9	19,003	250	1.3
Upper Molina	8.6	32,284	150	0.5

Great Plains Region

The plant with the highest potential incremental generation increase from efficiency improvements in the Great Plains region is Canyon Ferry with a gain of 25,391 MWh/yr (Table 9-10). The additional generation at Canyon Ferry corresponds to a 6.7% increase over its existing annual generation. The other plants with generation increases corresponding to 6.7% over their existing annual generation, the highest potential percent increase in generation from efficiency improvements, are Big Thompson, Boysen, Estes, Heart Mountain, Marys Lake, and Pilot Butte, which have potential generation increases ranging from 269 MWh/yr at Pilot Butte to 7,232 MWh/yr at Estes. In addition to Canyon Ferry, the other plants with BCRs greater than one in the Great Plains region were Shoshone and Guernsey which have potential increases in generation from efficiency improvements of 1,374 MWh/yr and 934 MWh/yr, respectively, that correspond to 5.4% and 4.6% increases over their existing annual generation, respectively.

Table 9-10. Efficiency Gain Results - Great Plains Region

Plant	Installed Capacity	Annual Average Existing Generation	Incremental Generation from Efficiency Improvements	
	(MW)	(MWh/yr)	(MWh/yr)	(%)
Shoshone	3.0	25,487	1,374	5.4
Canyon Ferry	50	380,509	25,391	6.7
Guernsey	6.4	20,194	934	4.6
Pilot Butte	1.6	4,013	269	6.7
Buffalo Bill	18	74,174	4,268	5.8
Glendo	38	65,902	4,130	6.3
Fremont Canyon	67	247,405	14,075	5.7
Boysen	15	71,996	4,825	6.7
Kortes	36	147,781	1,943	1.3
Big Thompson	4.5	12,248	824	6.7
Alcova	41	118,203	2,406	2.0
Seminoe	52	141,940	8,288	5.8
Yellowtail	250	818,027	21,612	2.6
Green Mountain	26	64,728	2,037	3.1
Mount Elbert	200	226,803	14,379	6.3
Flatiron [1]	94.5	241,042	14,436	6.0
Estes	45	107,555	7,232	6.7
Pole Hill	38	184,741	10,906	5.9
Heart Mountain	5.0	21,782	1,465	6.7
Marys Lake	8.1	40,514	2,713	6.7
Spirit Mountain	4.5	12,570	652	5.2

Notes
[1] Installed capacity at Flatiron is 94.5 MW. Only Units 1 and 2 (81.3 MW) were included in the modeling.

Pacific Northwest Region

The plant with the highest potential incremental generation increase from efficiency improvements in the Pacific Northwest region is Grand Coulee with a gain of 101,669 MWh/yr (Table 9-11). The additional generation at Grand Coulee is only a 0.5% increase over its existing annual generation. The magnitude of the incremental generation is likely due to the fact that there are 33 units at the plant and not that the units have undergone significant efficiency deterioration due to age. The plant with the highest percent increase in generation over its existing annual generation is Anderson Ranch with a potential increase of 6.2% which corresponds to an additional 9,215 MWh/yr. The plants with BCRs greater than one in the Pacific Northwest region, Black Canyon, Boise Diversion, Palisades, and Minidoka, have potential increases in generation from efficiency improvements of 2,211 MWh/yr, 104 MWh/yr, 22,716 MWh/yr, and 2,403 MWh/yr, respectively. These increases in generation represent 3.3%, 0.7%, 3.2%, and 1.7% increases over their existing annual generation, respectively.

Table 9-11. Efficiency Gain Results - Pacific Northwest Region

Plant	Installed Capacity	Annual Average Existing Generation	Incremental Generation from Efficiency Improvements	
	(MW)	(MWh/yr)	(MWh/yr)	(%)
Black Canyon	10	67,078	2,211	3.3
Boise Diversion	3.5	15,247	104	0.7
Palisades	177	706,936	22,716	3.2
Minidoka	28	137,585	2,403	1.7
Anderson Ranch	40	148,136	9,215	6.2
Chandler	12	60,349	461	0.8
Grand Coulee	6,495	21,850,471	101,669	0.5
Hungry Horse	428	930,345	49,272	5.3
Green Springs	17	63,822	1,686	2.6
Roza	13	61,990	3,753	6.1

Lower Colorado Region

The plant with the highest potential incremental generation increase from efficiency improvements in the Lower Colorado region is Hoover with a gain or 107,275 MWh/yr (Table 9-12). The additional generation at Hoover corresponds to a 2.0% increase over its existing annual generation. Like Grand Coulee, the magnitude of the incremental generation is likely due to the fact that there are 19 units at the plant and not that the units have undergone significant efficiency deterioration due to age. The other two plants in the Lower Colorado region, Davis and Parker, have potential incremental generation increases of 26,471 MWh/yr and 7,445 MWh/yr, respectively, which correspond to relatively small increases over their existing annual generation of 2.0% and 1.3%, respectively.

Table 9-12. Efficiency Gain Results - Lower Colorado Region

Plant	Installed Capacity	Annual Average Existing Generation	Incremental Generation from Efficiency Improvements	
	(MW)	(MWh/yr)	(MWh/yr)	(%)
Davis	255	1,300,376	26,471	2.0
Parker	120	566,182	7,445	1.3
Hoover	2,079	5,269,763	107,275	2.0

Summary of Efficiency Gains Results

Significant potential for annual generation increases from efficiency improves exist at the Reclamation plants based on this screening level assessment. As was previously described, the efficiency improvements are based on a standardized efficiency degradation curve that considers the age of the units and assumes replacement with a modern turbine design. A total of 36 plants could potentially increase their annual generation by greater than 3%. The plants are ranked based on the percent increase in generation over the simulated annual generation (Table 9-13). The plant with largest potential generation increase from efficiency gains is Hungry Horse in the Pacific Northwest. Several of the plants in the Mid-Pacific Region also have potential gains from efficiency related opportunities. The plant with the largest potential percent increase over its existing annual generation is O'Neill in the Mid-Pacific region.

Table 9-13. Summary - Efficiency Gain Opportunities >3%

Rank [1]	Plant	Region	Installed Capacity	Annual Average Existing Generation	Incremental Generation from Efficiency Improvements	
			(MW)	(MWh/yr)	(MWh/yr)	(%)
1	O'Neill	Mid-Pacific	25	5,503	371	6.7
2	Big Thompson	Great Plains	4.5	12,248	824	6.7
3	Heart Mountain	Great Plains	5.0	21,782	1,465	6.7
4	San Luis [2]	Mid-Pacific	424	304,679	20,490	6.7
5	Estes	Great Plains	45	107,555	7,232	6.7
6	Fontenelle	Upper Colorado	10	55,444	3,722	6.7
7	Boysen	Great Plains	15	71,996	4,825	6.7
8	Pilot Butte	Great Plains	1.6	4,013	269	6.7
9	Nimbus	Mid-Pacific	13.5	69,746	4,671	6.7
10	Marys Lake	Great Plains	8.1	40,514	2,713	6.7
11	Canyon Ferry	Great Plains	50	380,509	25,391	6.7
12	New Melones	Mid-Pacific	382	470,677	29,916	6.4
13	Mount Elbert	Great Plains	200	226,803	14,379	6.3
14	Glendo	Great Plains	38	65,902	4,130	6.3
15	Anderson Ranch	Pacific Northwest	40	148,136	9,215	6.2
16	Spring Creek	Mid-Pacific	180	590,037	36,681	6.2
17	Roza	Pacific Northwest	13	61,990	3,753	6.1
18	Trinity	Mid-Pacific	140	517,251	31,209	6.0
19	Flatiron [3]	Great Plains	94.5	241,042	14,436	6.0
20	Pole Hill	Great Plains	38	184,741	10,906	5.9
21	Stampede	Mid-Pacific	3.65	12,915	761	5.9
22	Seminoe	Great Plains	52	141,940	8,288	5.8
23	Buffalo Bill	Great Plains	18	74,174	4,268	5.8
24	Fremont Canyon	Great Plains	67	247,405	14,075	5.7
25	Keswick	Mid-Pacific	117	461,014	25,762	5.6
26	Shoshone	Great Plains	3.0	25,487	1,374	5.4
27	Morrow Point	Upper Colorado	173	363,625	19,421	5.3
28	Hungry Horse	Pacific Northwest	428	930,345	49,272	5.3
29	McPhee	Upper Colorado	1.3	5,679	301	5.3
30	Towaoc	Upper Colorado	11	19,381	1,014	5.2
31	Spirit Mountain	Great Plains	4.5	12,570	652	5.2
32	Guernsey	Great Plains	6.4	20,194	934	4.6
33	Black Canyon	Pacific Northwest	10.2	67,078	2,211	3.3
34	Blue Mesa	Upper Colorado	86.4	265,164	8,673	3.3
35	Palisades	Pacific Northwest	176.6	706,936	22,716	3.2
36	Green Mountain	Great Plains	26.0	64,728	2,037	3.1

Notes

[1] Plants are ranked based on the percent of additional generation from efficiency improvements over their existing annual (simulated) generation.

[2] Installed capacity of 424 MW for San Luis includes the Federal and CA shares. The Federal share is 202 MW.

[3] Installed capacity at Flatiron is 94.5 MW. Only Units 1 and 2 (81.3 MW) were included in the modeling.

Greenhouse Gas Reduction Opportunities

Three potential opportunities for GHG reduction have been determined in this assessment. These reduction opportunities, or offsets, are from efficiency improvements, capacity additions, and avoided outage losses, Since GHG offsets are directly related to generation, the incremental generation, or avoided lost generation for outages, and the GHG offsets are shown in the results tables. The GHG offsets are summarized by region in Tables 9-14 through 9-18 for each of the five Reclamation regions and the plants are ranked within each region based on the maximum BCR from the five capacity addition increments included in the analysis. Economic benefits were not assigned to greenhouse gas offsets in this study. GHG offsets were not assigned dollar values because there is currently a great deal of uncertainty regarding their future valuation. The energy and economics model does include an input placeholder for potential valuation of GHG offsets in future studies. Individual state Green Energy incentives are generally not applicable to Federal projects and also contain restrictions on incremental capacity size and run-of-river operation that would preclude application to the capacity addition alternatives considered in this report.

The GHG offsets for efficiency improvements are based on generation increases from an upgrade to a new, modern turbine, which corresponds to 1.5% efficiency increase for plants that have not been rehabilitated in the last 15 years, and the increase in generation from rehabilitating a turbine to its original condition from its current state where the efficiency deterioration is a function of the age. The additional generation and GHG offsets shown for capacity additions correspond to the capacity addition increment with the highest BCR. The GHG offsets from an avoided outage of a unit on an annual basis are shown for the generation potentially lost from the final logical unit. For the majority of plants, the largest opportunity for GHG offsets is from an avoided outage of a unit, which supports investment in Reclamation’s assets to minimize risk of failure based on the potential risk of generation lost and GHG emissions.

Mid-Pacific Region

The GHG offsets and associated generation for each of the 11 plants in the Mid-Pacific region are presented in Table 9-14.

Table 9-14. GHG Reduction Results - Mid-Pacific Region

Plant	GHG Offsets from Incremental Generation from Efficiency Improvements		GHG Offsets from Incremental Generation from Hydraulic Capacity Increases [1]		GHG Offsets from Avoided Energy Losses [2]	
	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr
Nimbus	4,671	1,890	6,104	2,068	21,275	8,607
Folsom	14,127	6,611	32,607	11,034	59,560	27,871
Shasta	22,831	10,684	73,426	24,380	64,233	30,058
Stampede	761	308	1,669	514	7,983	3,230
Keswick	25,762	11,239	26,278	9,419	44,802	19,545
Trinity	31,209	14,604	17,625	8,038	106,815	49,984
Judge Francis Carr	0	0	4,476	2,095	129,142	60,431
Spring Creek	36,681	17,165	12,180	5,662	88,337	41,337
San Luis	20,490	8,289	5,289	2,140	326	132
New Melones	29,916	13,999	7,830	3,664	4,568	2,138
O'Neill	371	173	251	117	306	143

Notes
[1] Incremental GHG offsets are based on the hydraulic capacity increase increment with the highest BCR.
[2] GHG offsets from avoided energy losses are based on a generic split between on-peak and off-peak hours depending on whether the plant is operated as a peaking, base load or intermediate plant.
GHG - Greenhouse Gas

The largest potential GHG offsets shown in Table 9-14 come from efficiency improvements for three of the plants, New Melones, O'Neill, and San Luis. The largest opportunity for GHG offsets for the remaining plants comes from a year-long avoided outage of the final logical unit. Overall, the largest GHG offset opportunity results from a year-long avoided outage of the final logical unit at Judge Francis Carr which would equate to a generation loss of 129,142 MWh/yr and 60,431 metric tons of CO_2e/yr from an alternate generation source in the region.

Upper Colorado Region

The GHG offsets and associated generation for each of the 12 plants in the Upper Colorado region are presented in Table 9-15. The largest potential GHG offsets come from efficiency an installed capacity increase for only one plant in the region, Glen Canyon. For the rest of the plants, the largest opportunity for GHG offsets comes from a year-long avoided outage of the final logical unit. Overall, the largest GHG offset opportunity results from a year-long avoided outage of the final logical unit at Crystal which would result in 187,173 MWh/yr of additional generation and 150,177 metric tons of CO_2e/yr offset from generation of other energy sources in the region.

Table 9-15. GHG Reduction Results - Upper Colorado Region

Plant	GHG Offsets from Incremental Generation from Efficiency Improvements		GHG Offsets from Incremental Generation from Hydraulic Capacity Increases [1]		GHG Offsets from Avoided Energy Losses [2]	
	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr
Deer Creek	391	304	1,023	796	9,380	7,304
Crystal	3,386	2,716	10,950	6,308	187,173	150,177
McPhee	301	227	413	312	5,771	4,357
Fontenelle	3,722	2,987	4,774	2,605	56,394	45,248
Glen Canyon	38,055	29,631	71,082	39,686	46,093	35,890
Towaoc	1,014	814	1,120	899	19,704	15,809
Flaming Gorge	3,891	3,030	13,495	7,302	41,896	32,622
Blue Mesa	8,673	6,547	3,219	1,929	24,308	18,351
Morrow Point	19,421	14,662	10,279	7,052	20,681	15,613
Elephant Butte	2,374	1,905	357	287	10,535	8,452
Lower Molina	250	195	133	64	19,003	14,797
Upper Molina	150	117	8	6	32,284	25,137

Notes

[1] Incremental GHG offsets are based on the hydraulic capacity increase increment with the highest BCR.

[2] GHG offsets from avoided energy losses are based on a generic split between on-peak and off-peak hours depending on whether the plant is operated as a peaking, base load or intermediate plant.

GHG - Greenhouse Gas

The GHG offsets and associated generation for each of the 21 plants in the Great Plains region are presented in Table 9-16. The largest potential GHG offsets come from efficiency improvements at five plants in the region, Estes, Flatiron, Mount Elbert, Seminoe, and Yellowtail. The largest opportunity for GHG offsets for the remaining plants comes from a year-long avoided outage of the final logical unit. Overall, the largest GHG offset opportunity results from a year-long avoided outage of the final logical unit at Pole Hill which would equate to a generation loss of 187,914 MWh/yr and 98,135 metric tons of CO_2e/yr from an alternate generation source in the region.

Table 9-16. GHG Reduction Results - Great Plains Region

Plant	GHG Offsets from Incremental Generation from Efficiency Improvements		GHG Offsets from Incremental Generation from Hydraulic Capacity Increases [1]		GHG Offsets from Avoided Energy Losses [2]	
	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr
Shoshone	1,374	734	12,347	4,055	25,922	13,514
Canyon Ferry	25,391	12,742	17,576	8,820	72,993	36,630
Guernsey	934	489	8,887	2,580	9,928	4,624
Pilot Butte	269	133	1,800	518	1,947	926
Buffalo Bill	4,268	2,277	3,985	2,077	15,231	7,941
Glendo	4,130	2,146	8,726	3,126	27,946	13,020
Fremont Canyon	14,075	7,588	9,238	4,960	64,793	34,789
Boysen	4,825	2,583	5,322	2,176	16,163	8,423
Kortes	1,943	1,124	4,594	1,625	13,075	6,845
Big Thompson	824	432	494	237	12,460	5,979
Alcova	2,406	1,392	2,003	944	23,517	12,583
Seminoe	8,288	4,451	5,592	2,486	7,507	3,978
Yellowtail	21,612	12,502	8,526	3,370	21,586	11,498
Green Mountain	2,037	1,100	2,065	725	6,331	3,243
Mount Elbert	14,379	8,434	3,965	2,410	0	0
Flatiron [3]	14,436	7,762	4,153	2,207	625	332
Estes	7,232	3,909	1,854	1,005	0	0
Pole Hill	10,906	5,538	3,173	1,657	187,914	98,135
Heart Mountain	1,465	778	481	227	22,158	11,150
Marys Lake	2,713	1,389	687	372	41,201	22,326
Spirit Mountain	652	321	220	105	12,790	6,090

Notes

[1] Incremental GHG offsets are based on the hydraulic capacity increase increment with the highest BCR.

[2] GHG offsets from avoided energy losses are based on a generic split between on-peak and off-peak hours depending on whether the plant is operated as a peaking, base load or intermediate plant.

[3] Only Units 1 and 2 (81.3 MW) at Flatiron were included in the modeling.

GHG - Greenhouse Gas

Pacific Northwest Region

The GHG offsets and associated generation for each of the ten plants in the Pacific Northwest region are presented in Table 9-17. The largest potential GHG offsets come from efficiency improvements at two plants in the region, Grand Coulee and Hungry Horse. The largest potential GHG offsets come from capacity additions for one plant in the Pacific Northwest, Boise Diversion. The largest opportunity for GHG offsets for the remaining plants comes from a year-long avoided outage of the final logical unit. Overall, the largest GHG offset opportunity results from a year-long avoided outage of the final logical unit at Palisades which would equate to a generation loss of 112,976 MWh/yr and 61,024 metric tons of CO_2e/yr from an alternate generation source in the region.

Table 9-17. GHG Reduction Results - Pacific Northwest Region

Plant	GHG Offsets from Incremental Generation from Efficiency Improvements		GHG Offsets from Incremental Generation from Hydraulic Capacity Increases [1]		GHG Offsets from Avoided Energy Losses [2]	
	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr
Black Canyon	2,211	1,194	19,026	6,815	28,133	15,196
Boise Diversion	104	60	6,231	2,778	4,738	2,741
Palisades	22,716	12,270	72,778	34,565	112,976	61,024
Minidoka	2,403	1,298	3,098	1,673	34,500	18,635
Anderson Ranch	9,215	4,978	19,805	6,039	47,816	25,828
Chandler	461	249	594	321	22,232	12,008
Grand Coulee	101,669	54,916	141	76	8,431	4,554
Hungry Horse	49,272	28,502	19,275	10,963	12,551	7,260
Green Springs	1,686	911	0	0	63,822	34,473
Roza	3,753	2,027	1,062	574	63,053	34,058

Notes

[1] Incremental GHG offsets are based on the hydraulic capacity increase increment with the highest BCR.

[2] GHG offsets from avoided energy losses are based on a generic split between on-peak and off-peak hours depending on whether the plant is operated as a peaking, base load or intermediate plant.

GHG - Greenhouse Gas

Lower Colorado Region

The GHG offsets and associated generation for each of the three plants in the Lower Colorado region are presented in Table 9-18. The largest potential GHG offsets come from efficiency improvements for Hoover, while the largest opportunity for GHG offsets at Davis and Parker come from a year-long avoided outage of the final logical unit. Overall, the largest GHG offset opportunity results from efficiency improvements at Hoover which would result in 107,275 MWh/yr of additional generation and 60,488 metric tons of CO_2e/yr offset from generation of other energy sources in the region.

Table 9-18. GHG Reduction Results - Lower Colorado Region

Plant	GHG Offsets from Incremental Generation from Efficiency Improvements		GHG Offsets from Incremental Generation from Hydraulic Capacity Increases [1]		GHG Offsets from Avoided Energy Losses [2]	
	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr
Davis	26,471	14,926	15,784	8,900	47,473	26,768
Parker	7,445	4,198	15,049	7,093	30,107	16,976
Hoover	107,275	60,488	0	0	69	39

Notes

[1] Incremental GHG offsets are based on the hydraulic capacity increase increment with the highest BCR.

[2] GHG offsets from avoided energy losses are based on a generic split between on-peak and off-peak hours depending on whether the plant is operated as a peaking, base load or intermediate plant.

GHG - Greenhouse Gas

Summary of Greenhouse Gas Reduction Opportunities Results

The potential GHG reduction opportunities and associated generation increases for each of the five Reclamation regions is summarized in Table 9-19. The largest potential GHG offsets and the largest annual generation increases from efficiency improvements is in the Pacific Northwest region. The largest potential GHG offsets and associated generation increases from capacity additions is in the Mid-Pacific region. The largest opportunity for GHG offsets from avoided outages lasting a year is in the Upper Colorado region. However the largest opportunity for avoided energy loss from outages lasting a year is in Great Plains Region. The difference in regions for GHG offsets and avoided energy loss opportunities associated with avoided outages can be explained by the regional mix of GHG emission sources that contribute to the GHG emission rates. Overall, the largest GHG offset opportunity results from a year-long avoided outage of the final logical unit for 4 of the 5 regions; the exception being Lower Colorado which has the largest GHG offset opportunity attributed to efficiency improvements. The results for the Lower Colorado region are primarily driven by Hoover which is the majority of the capacity in that region.

Table 9-19. Cumulative GHG Reduction Results by Region

Region	GHG Offsets from Incremental Generation from Efficiency Improvements		GHG Offsets from Incremental Generation from Hydraulic Capacity Increases [1]		GHG Offsets from Avoided Energy Losses [2]	
	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr	(MWh/yr)	metric tons CO2e/yr
Mid Pacific	186,818	84,961	187,735	69,129	527,348	243,476
Upper Colorado	81,627	63,134	116,853	67,246	473,221	373,756
Lower Colorado	141,191	79,612	30,833	15,993	77,649	43,783
Pacific Northwest	193,491	106,405	142,011	63,803	398,253	215,777
Great Plains	144,159	77,825	105,692	45,683	584,088	302,024

Notes

[1] Incremental GHG offsets are based on the summation of the hydraulic capacity increase increment for each plant with the highest BCR.

[2] GHG offsets from avoided energy losses are based on a generic split between on-peak and off-peak hours depending on whether the plant is operated as a peaking, base load or intermediate plant.

GHG - Greenhouse Gas

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Chapter 10 Conclusions

Based on the results of this planning-level study, the following conclusions can be made:

1. There is no indication of economically feasible capacity additions at over 80% of the existing Reclamation hydropower plants. This is generally a confirmation of an indication that excluded the existing Reclamation plants from a 2007 Federal study of potential hydropower development at Federal facilities. Most of the original plants that showed promise for capacity additions have been studied and capacity additions already completed in a power uprating program initiated by Reclamation in 1978.

2. Results show economically feasible potential capacity additions at 10 of the 58 plants. The 10 plants that show initial promise for capacity additions are mostly among the smallest of the 58 plants. Based on the highest benefit to cost ratio, the Shoshone plant is the highest ranked for capacity addition. Based on maximum net present value, the Palisades plant is the highest ranked. These 10 plants would be candidates for more detailed feasibility studies of capacity addition.

3. Selecting the capacity addition at each of the 10 plants that has the highest benefit to cost ratio would result in a total capacity addition of about 67 megawatts across the Reclamation power system. The 67 megawatt capacity addition would represent less than one-half of one percent of the existing total nameplate capacity of the 58 plants. If maximum net present value was the criterion for selecting the capacity addition, the economic capacity addition would rise to about 143 megawatts, still less than one percent of the existing total nameplate capacity. The Palisades plant alone has over 50% of the potentially economically feasible capacity addition.

4. There is substantial potential for generation increases from efficiency gains and substantial offsets of greenhouse gasses from fossil fuel-fired generation. Costs and benefits were not assigned to the efficiency gains or greenhouse gas offsets in this study.

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Chapter 12
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APPENDIX A

Capacity Addition Detailed Economic Results

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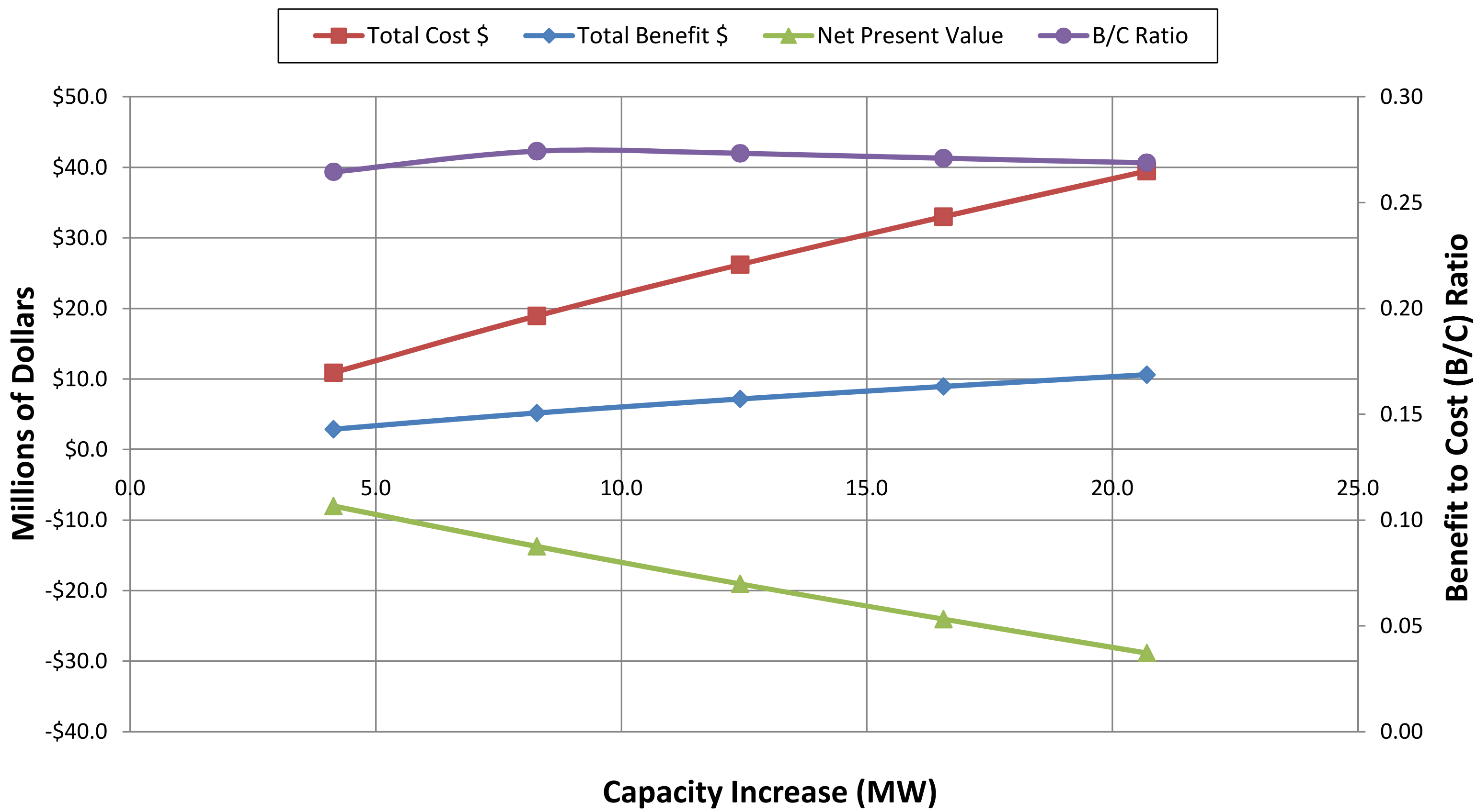
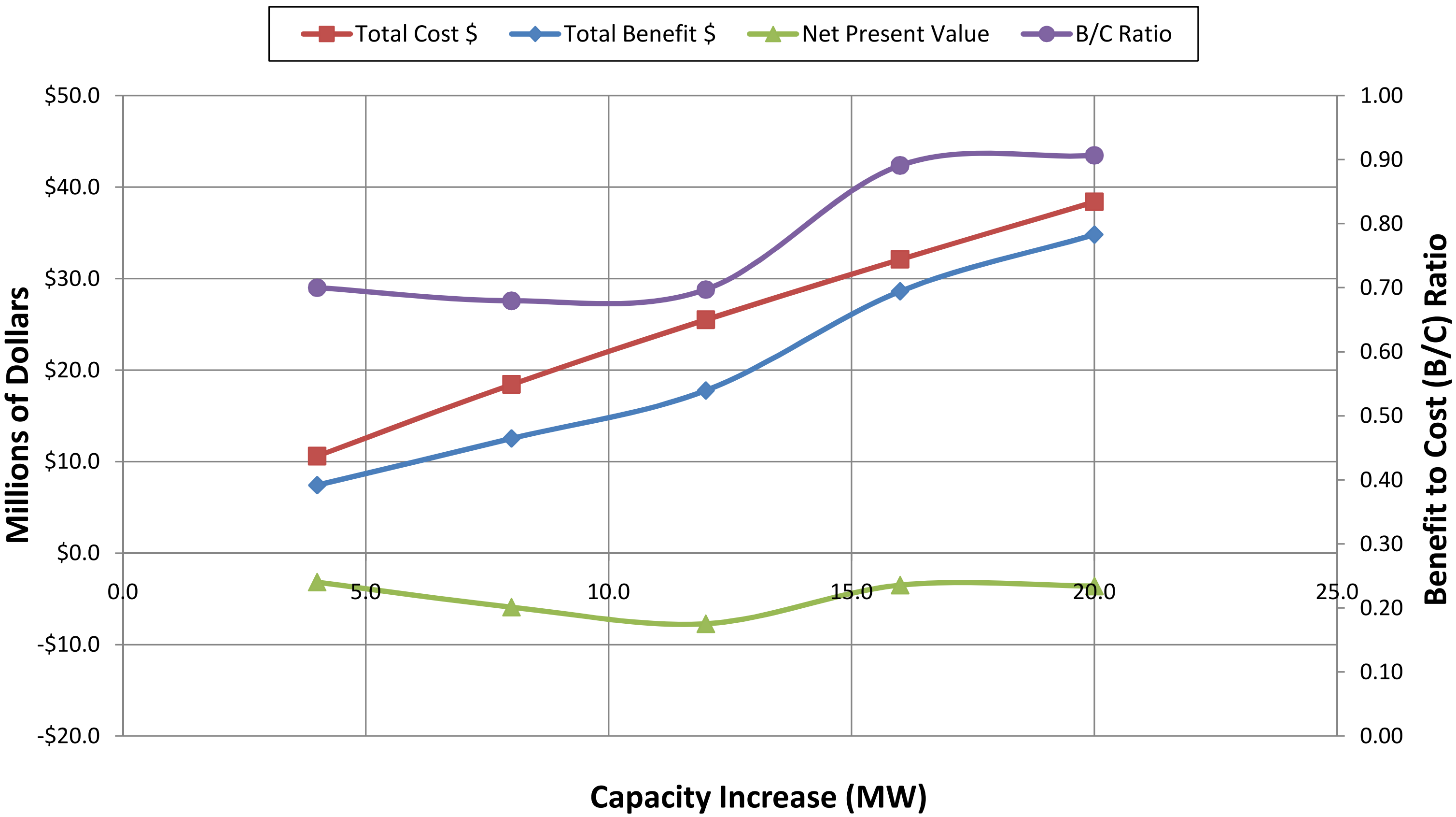
Summary of Capacity Increase Benefits and Costs
Alcova

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	4.1	1,162	3%	$7.5	$1,823	$10.9	$1.3	$1.6	$2.9	-$8.0	0.26
20%	8.3	2,003	3%	$13.3	$1,605	$18.9	$2.2	$3.0	$5.2	-$13.7	0.27
30%	12.4	2,647	2%	$18.5	$1,491	$26.2	$2.9	$4.3	$7.2	-$19.0	0.27
40%	16.6	3,186	2%	$23.4	$1,416	$33.0	$3.5	$5.5	$8.9	-$24.1	0.27
50%	20.7	3,662	2%	$28.2	$1,361	$39.5	$4.0	$6.6	$10.6	-$28.9	0.27



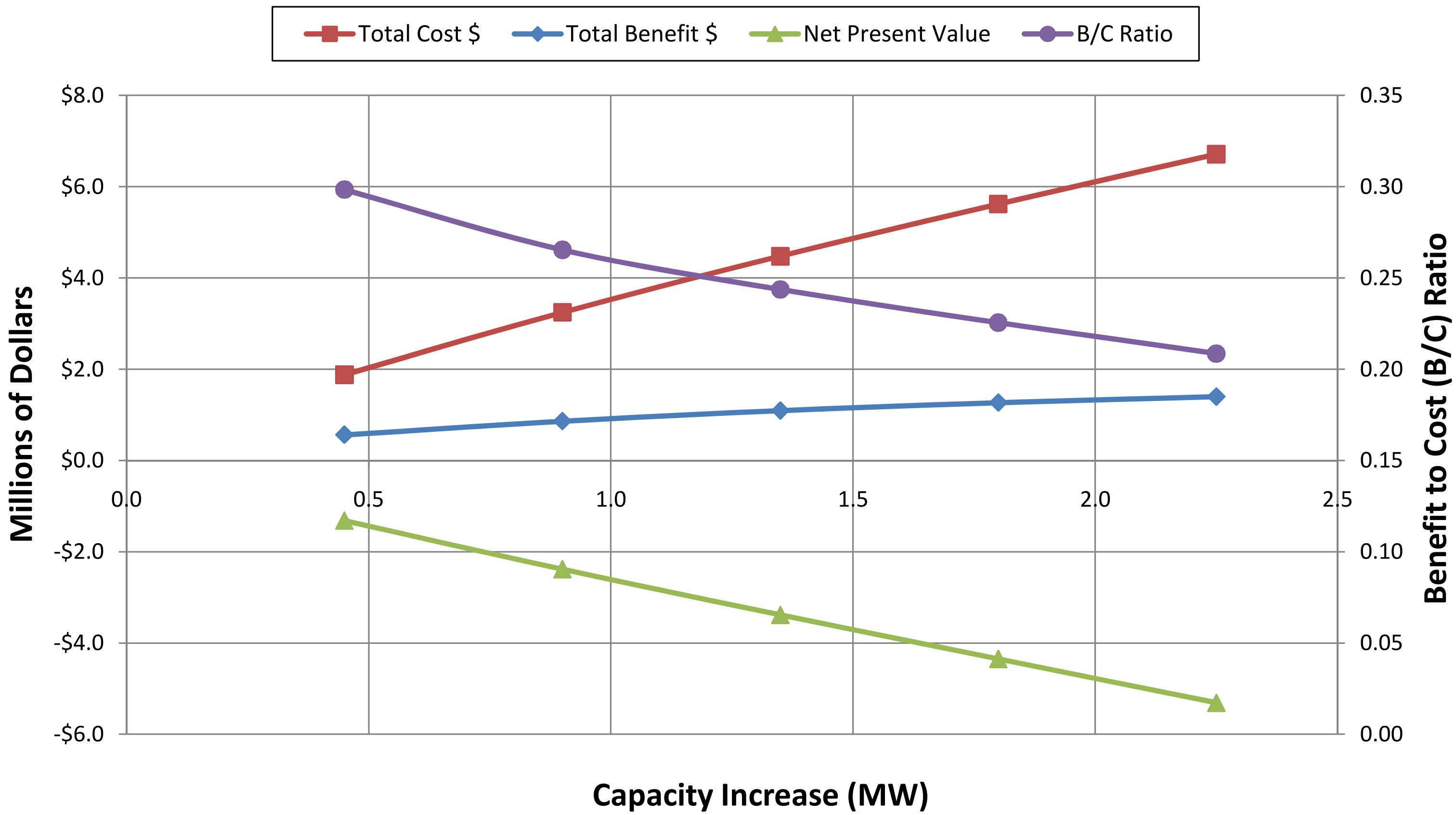
Summary of Capacity Increase Benefits and Costs
Anderson Ranch

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	4.0	3,701	11%	$7.3	$1,835	$10.6	$4.1	$3.3	$7.4	-$3.2	0.70
20%	8.0	6,108	9%	$12.9	$1,615	$18.4	$6.8	$5.8	$12.5	-$5.9	0.68
30%	12.0	8,595	8%	$18.0	$1,500	$25.5	$9.5	$8.3	$17.8	-$7.7	0.70
40%	16.0	14,201	10%	$22.8	$1,425	$32.1	$15.7	$12.9	$28.6	-$3.5	0.89
50%	20.0	17,220	10%	$27.4	$1,369	$38.4	$19.0	$15.8	$34.8	-$3.6	0.91



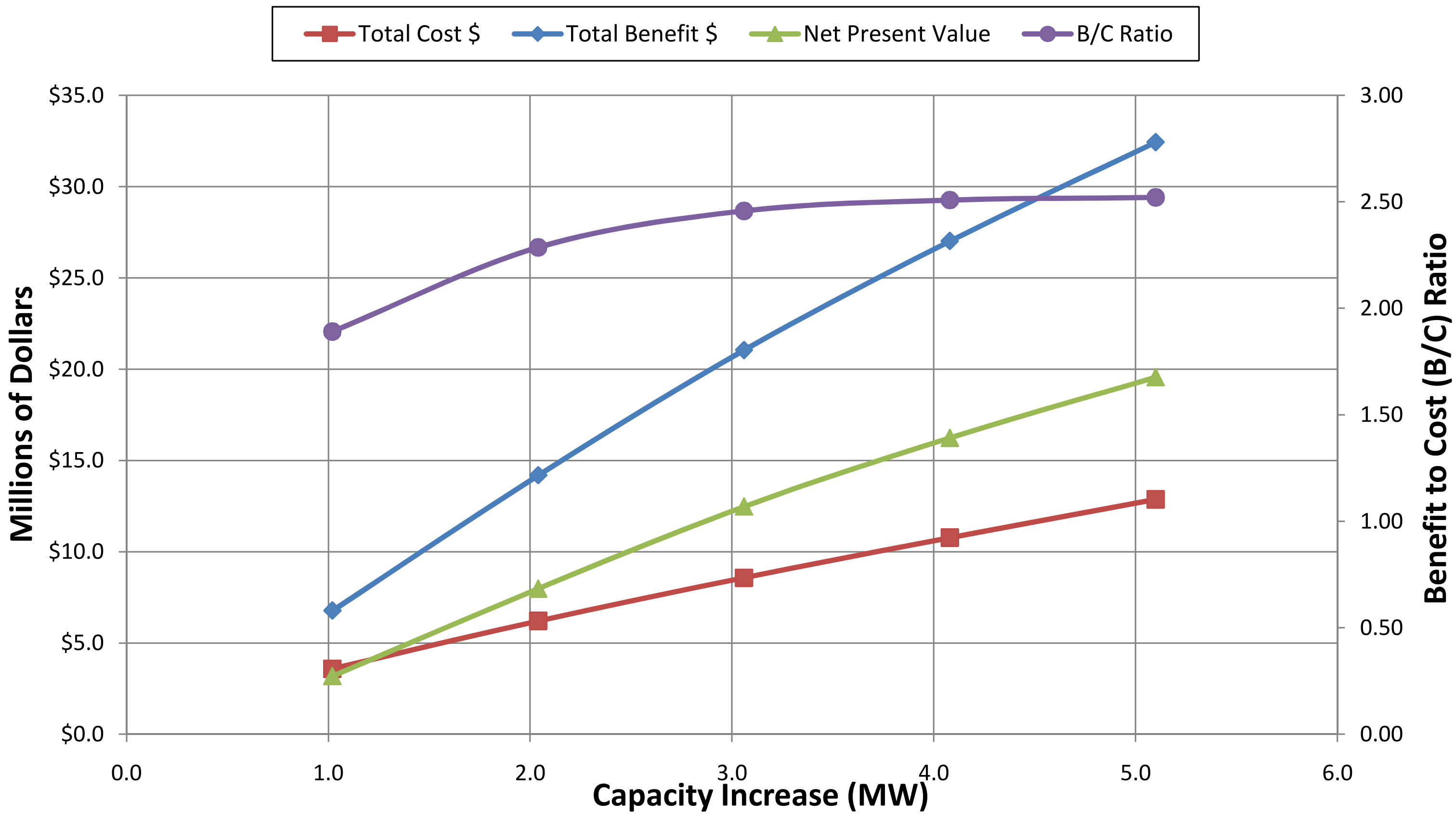
Summary of Capacity Increase Benefits and Costs
Big Thompson

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	0.5	283	7%	$1.3	$2,797	$1.9	$0.3	$0.3	$0.6	-$1.3	0.30
20%	0.9	409	5%	$2.2	$2,438	$3.2	$0.4	$0.5	$0.9	-$2.4	0.27
30%	1.4	493	4%	$3.0	$2,254	$4.5	$0.5	$0.6	$1.1	-$3.4	0.24
40%	1.8	545	3%	$3.8	$2,133	$5.6	$0.5	$0.7	$1.3	-$4.4	0.23
50%	2.3	571	3%	$4.6	$2,044	$6.7	$0.6	$0.8	$1.4	-$5.3	0.21



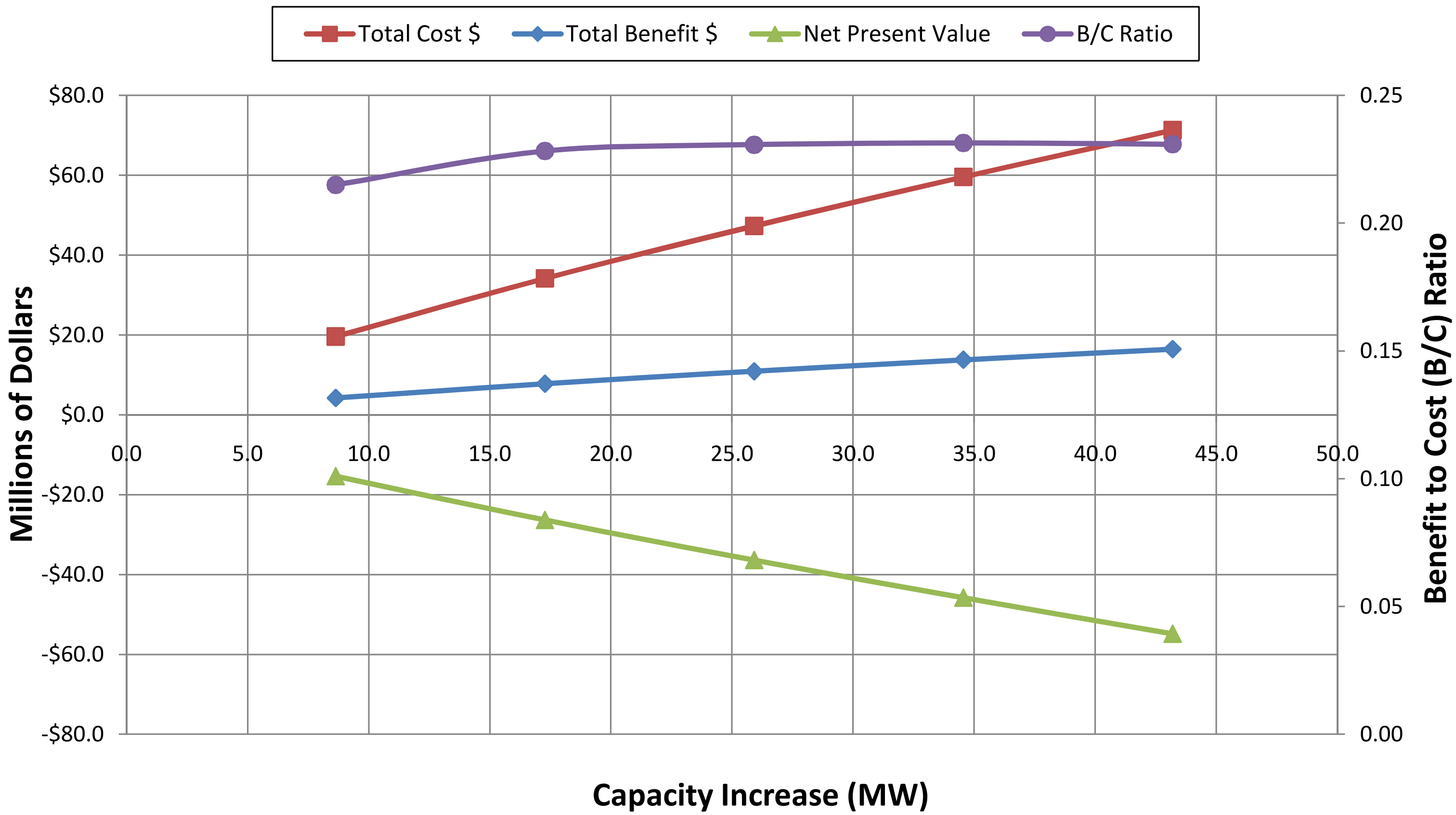
Summary of Capacity Increase Benefits and Costs
Black Canyon

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	1.0	4,022	45%	$2.4	$2,379	$3.6	$4.4	$2.3	$6.8	$3.2	1.89
20%	2.0	8,529	48%	$4.2	$2,082	$6.2	$9.4	$4.8	$14.2	$8.0	2.29
30%	3.1	12,616	47%	$5.9	$1,929	$8.6	$13.9	$7.1	$21.0	$12.5	2.46
40%	4.1	16,027	45%	$7.5	$1,828	$10.8	$17.7	$9.3	$27.0	$16.2	2.51
50%	5.1	19,026	43%	$8.9	$1,754	$12.9	$21.0	$11.4	$32.4	$19.6	2.52



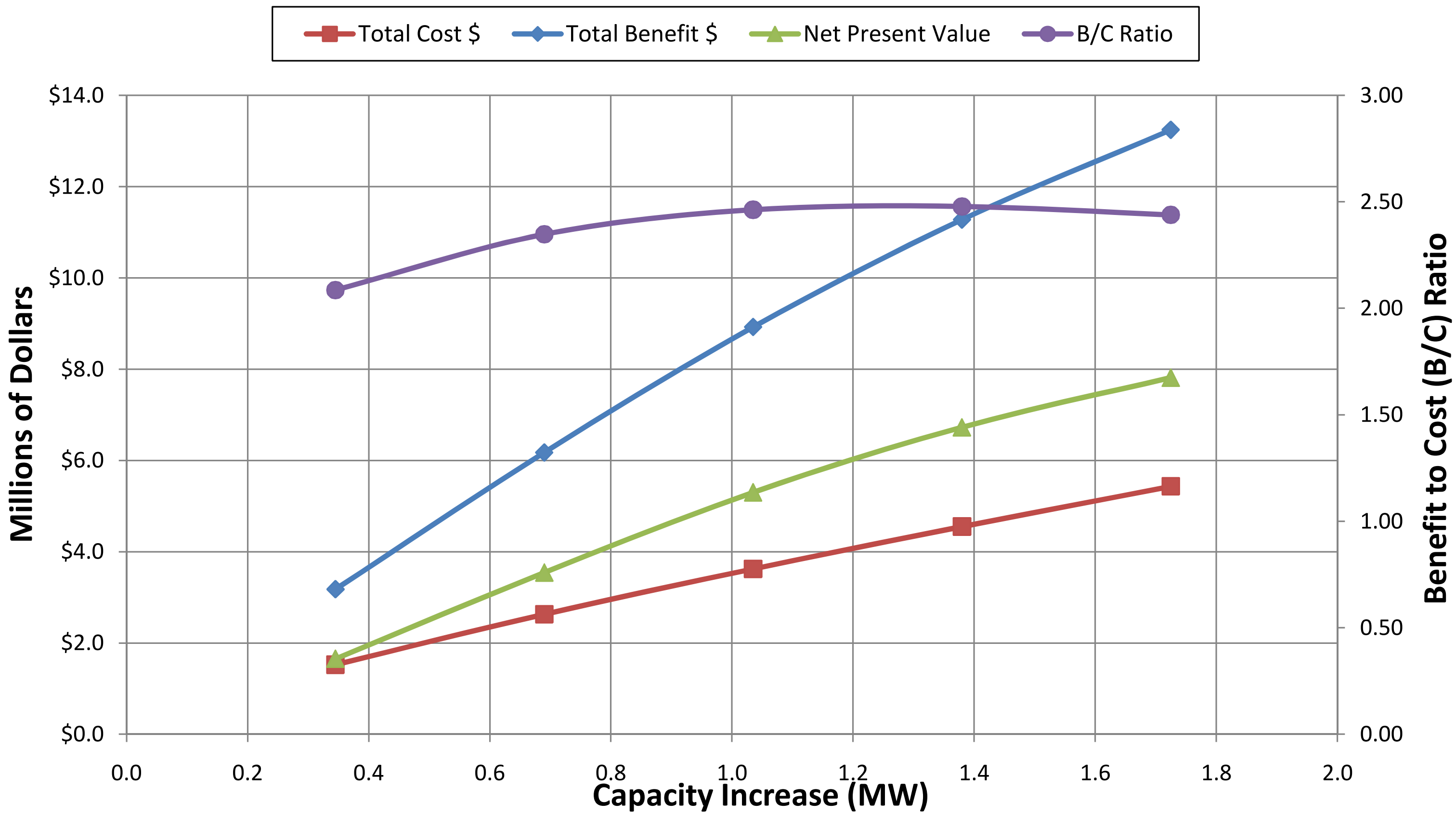
Summary of Capacity Increase Benefits and Costs
Blue Mesa

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	8.6	1,188	2%	$13.8	$1,592	$19.6	$1.7	$2.5	$4.2	-$15.4	0.21
20%	17.3	2,073	1%	$24.3	$1,405	$34.1	$2.9	$4.9	$7.8	-$26.4	0.23
30%	25.9	2,735	1%	$33.9	$1,307	$47.3	$3.9	$7.0	$10.9	-$36.4	0.23
40%	34.6	3,286	1%	$43.0	$1,243	$59.6	$4.6	$9.1	$13.8	-$45.8	0.23
50%	43.2	3,739	1%	$51.6	$1,195	$71.3	$5.3	$11.2	$16.5	-$54.8	0.23



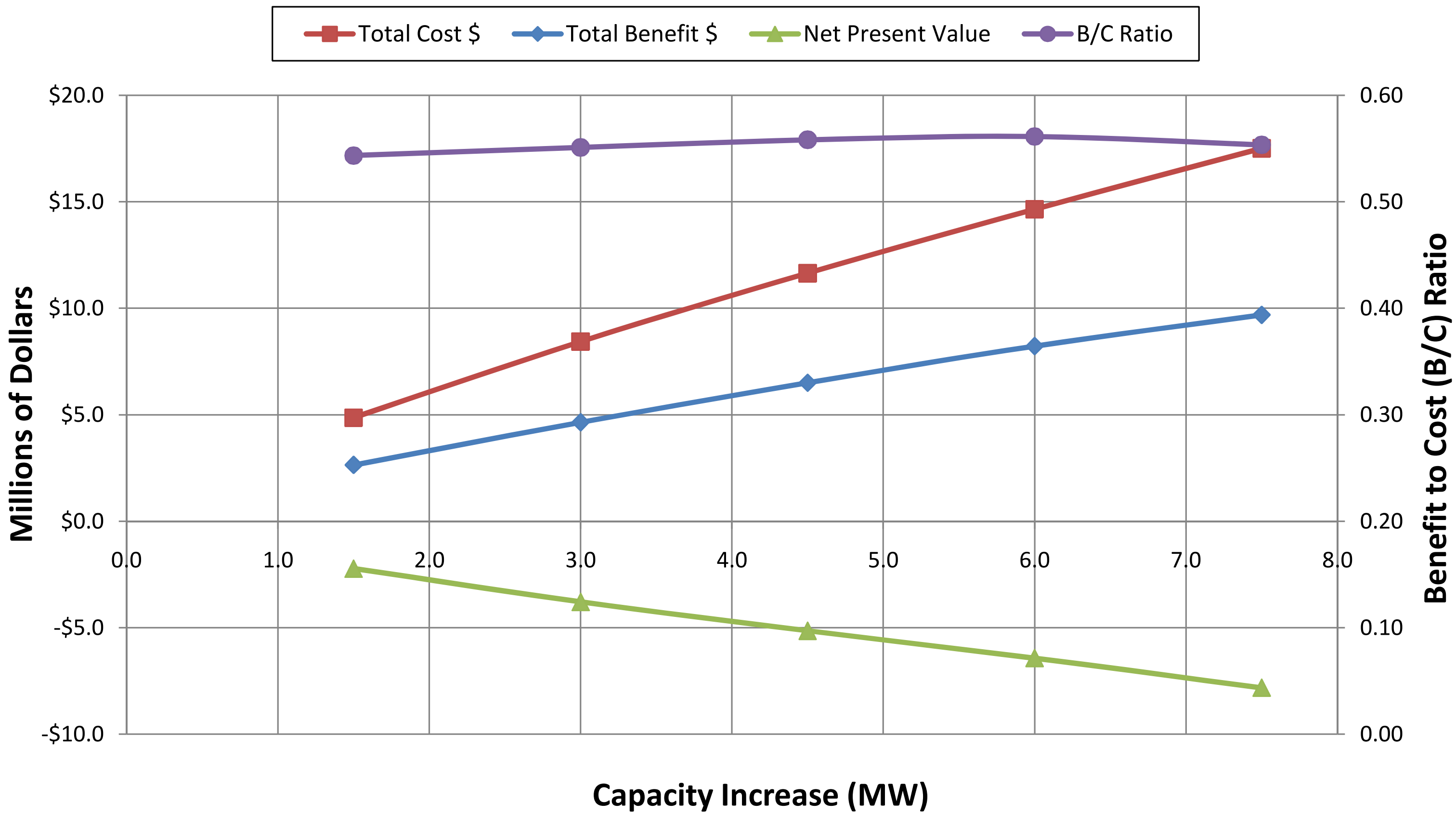
Summary of Capacity Increase Benefits and Costs
Boise Diversion

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	0.3	1,825	60%	$1.0	$2,951	$1.5	$2.3	$0.9	$3.2	$1.7	2.09
20%	0.7	3,527	58%	$1.8	$2,569	$2.6	$4.4	$1.7	$6.2	$3.5	2.35
30%	1.0	5,062	56%	$2.5	$2,373	$3.6	$6.3	$2.6	$8.9	$5.3	2.46
40%	1.4	6,327	52%	$3.1	$2,244	$4.6	$7.9	$3.3	$11.3	$6.7	2.48
50%	1.7	7,330	49%	$3.7	$2,150	$5.4	$9.2	$4.1	$13.2	$7.8	2.44



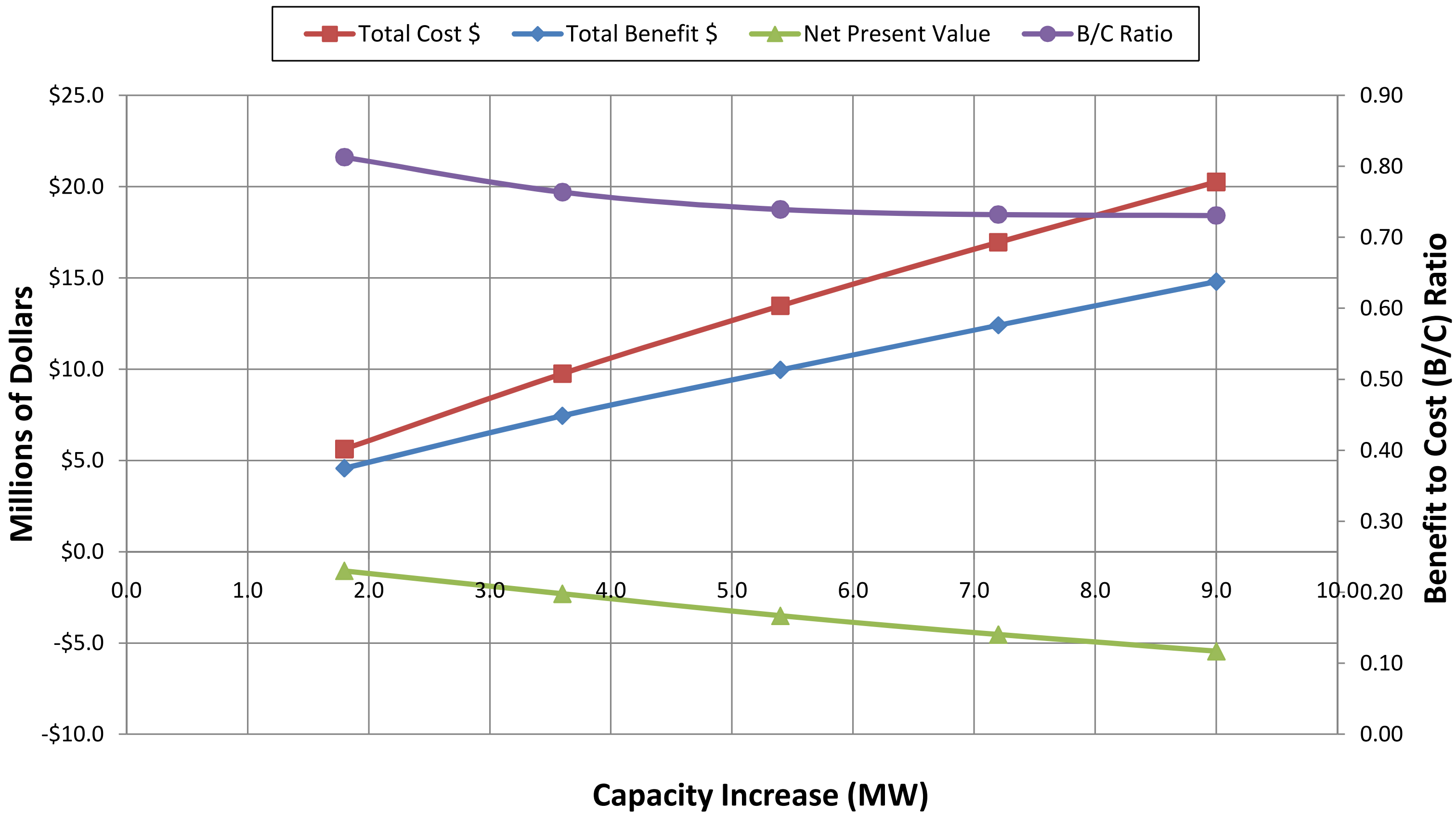
Summary of Capacity Increase Benefits and Costs
Boysen

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	1.5	1,366	10%	$3.3	$2,208	$4.9	$1.4	$1.2	$2.6	-$2.2	0.54
20%	3.0	2,360	9%	$5.8	$1,936	$8.4	$2.4	$2.2	$4.6	-$3.8	0.55
30%	4.5	3,267	8%	$8.1	$1,795	$11.6	$3.4	$3.1	$6.5	-$5.1	0.56
40%	6.0	4,097	8%	$10.2	$1,702	$14.6	$4.2	$4.0	$8.2	-$6.4	0.56
50%	7.5	4,776	7%	$12.3	$1,634	$17.5	$4.9	$4.8	$9.7	-$7.8	0.55



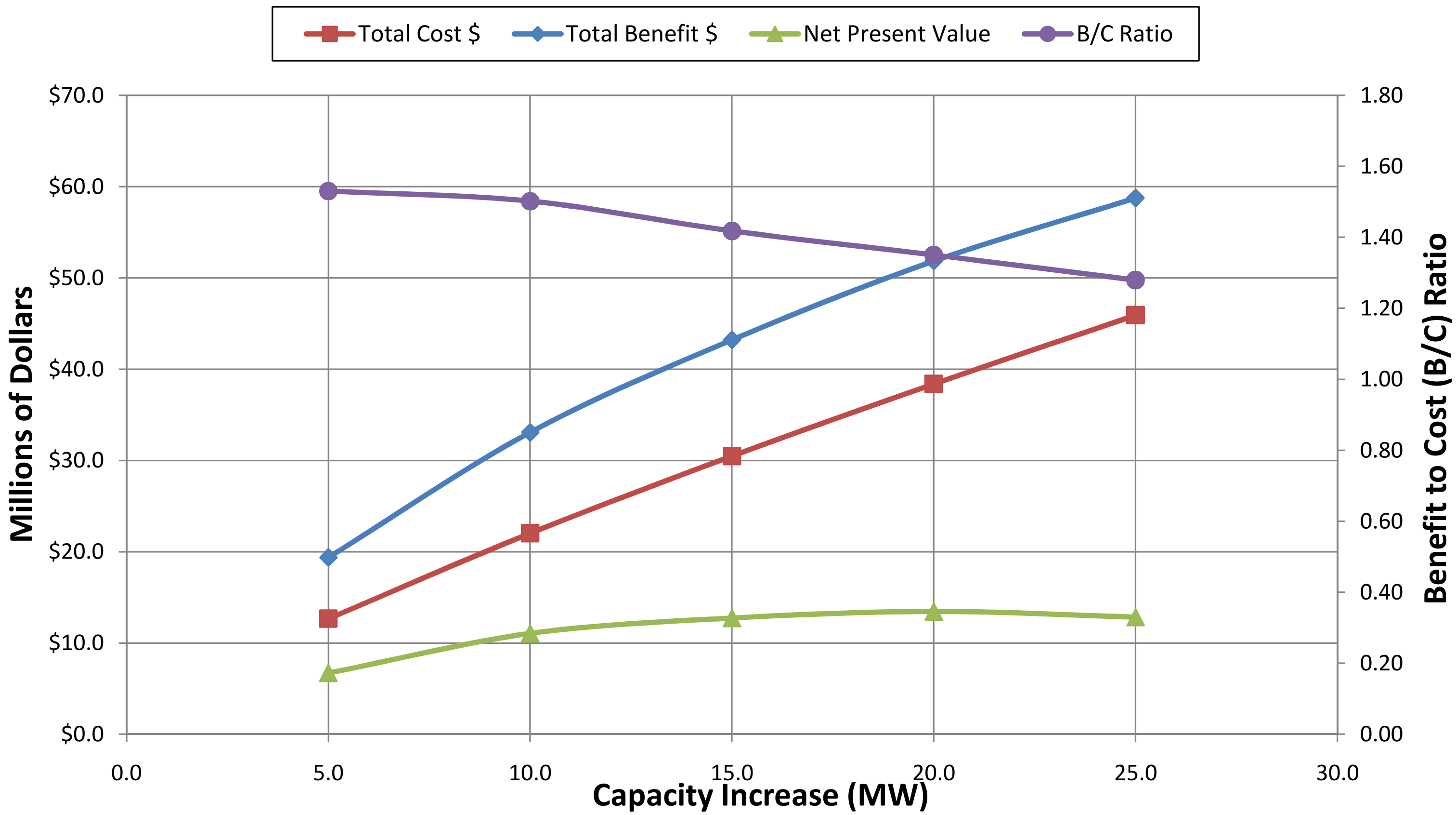
Summary of Capacity Increase Benefits and Costs
Buffalo Bill

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	1.8	2,452	16%	$3.8	$2,133	$5.6	$2.5	$2.0	$4.6	-$1.1	0.81
20%	3.6	3,920	12%	$6.7	$1,871	$9.7	$4.0	$3.4	$7.4	-$2.3	0.76
30%	5.4	5,174	11%	$9.4	$1,736	$13.5	$5.3	$4.6	$10.0	-$3.5	0.74
40%	7.2	6,392	10%	$11.9	$1,646	$16.9	$6.6	$5.8	$12.4	-$4.5	0.73
50%	9.0	7,579	10%	$14.2	$1,581	$20.3	$7.8	$7.0	$14.8	-$5.5	0.73



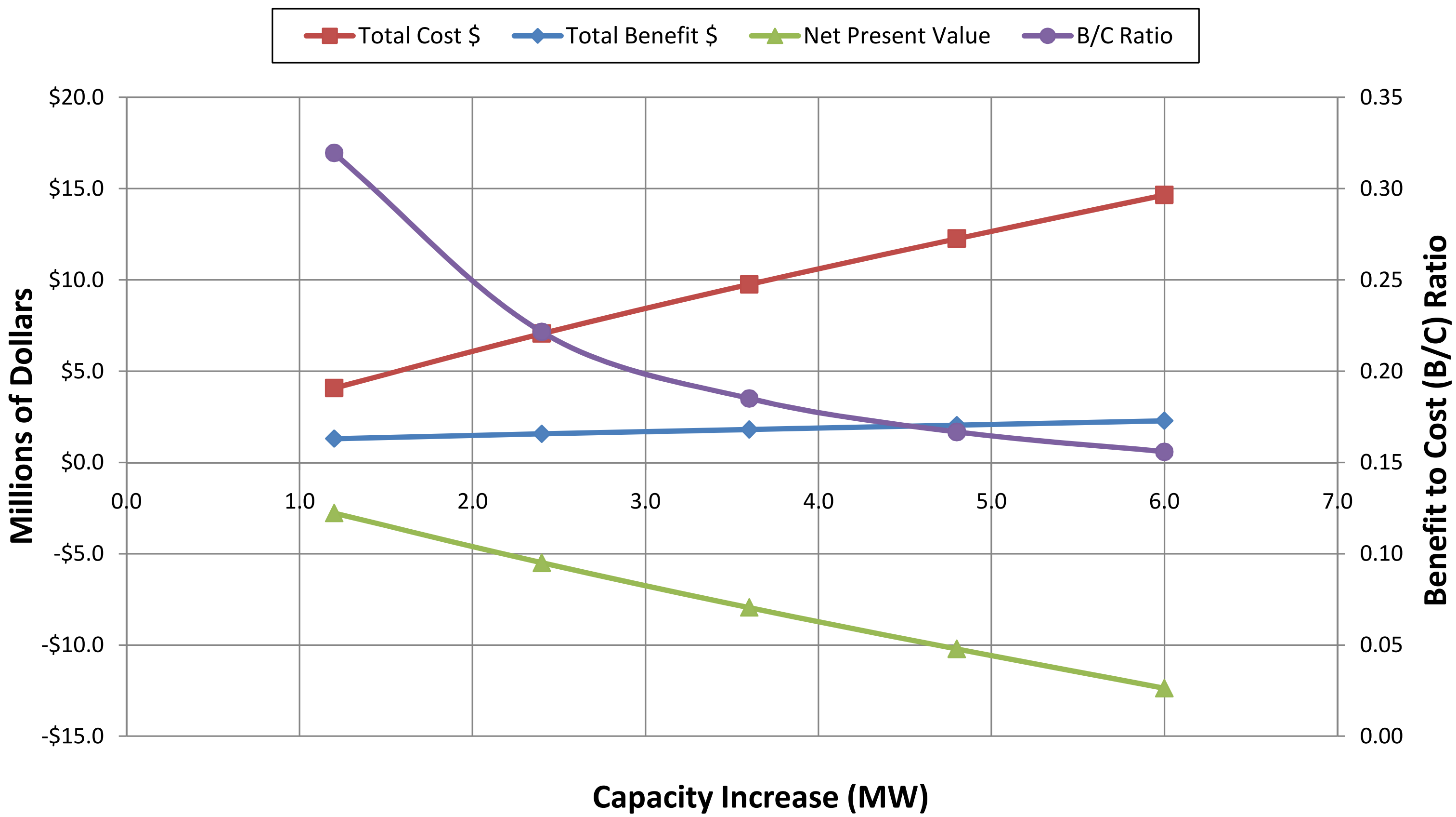
Summary of Capacity Increase Benefits and Costs
Canyon Ferry

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	5.0	11,211	26%	$8.8	$1,760	$12.7	$10.7	$8.7	$19.4	$6.7	1.53
20%	10.0	18,956	22%	$15.5	$1,551	$22.0	$18.1	$15.0	$33.1	$11.0	1.50
30%	15.0	24,524	19%	$21.6	$1,441	$30.5	$23.4	$19.8	$43.2	$12.7	1.42
40%	20.0	29,173	17%	$27.4	$1,369	$38.4	$27.9	$23.9	$51.8	$13.4	1.35
50%	25.0	32,781	15%	$32.9	$1,316	$45.9	$31.3	$27.4	$58.7	$12.8	1.28



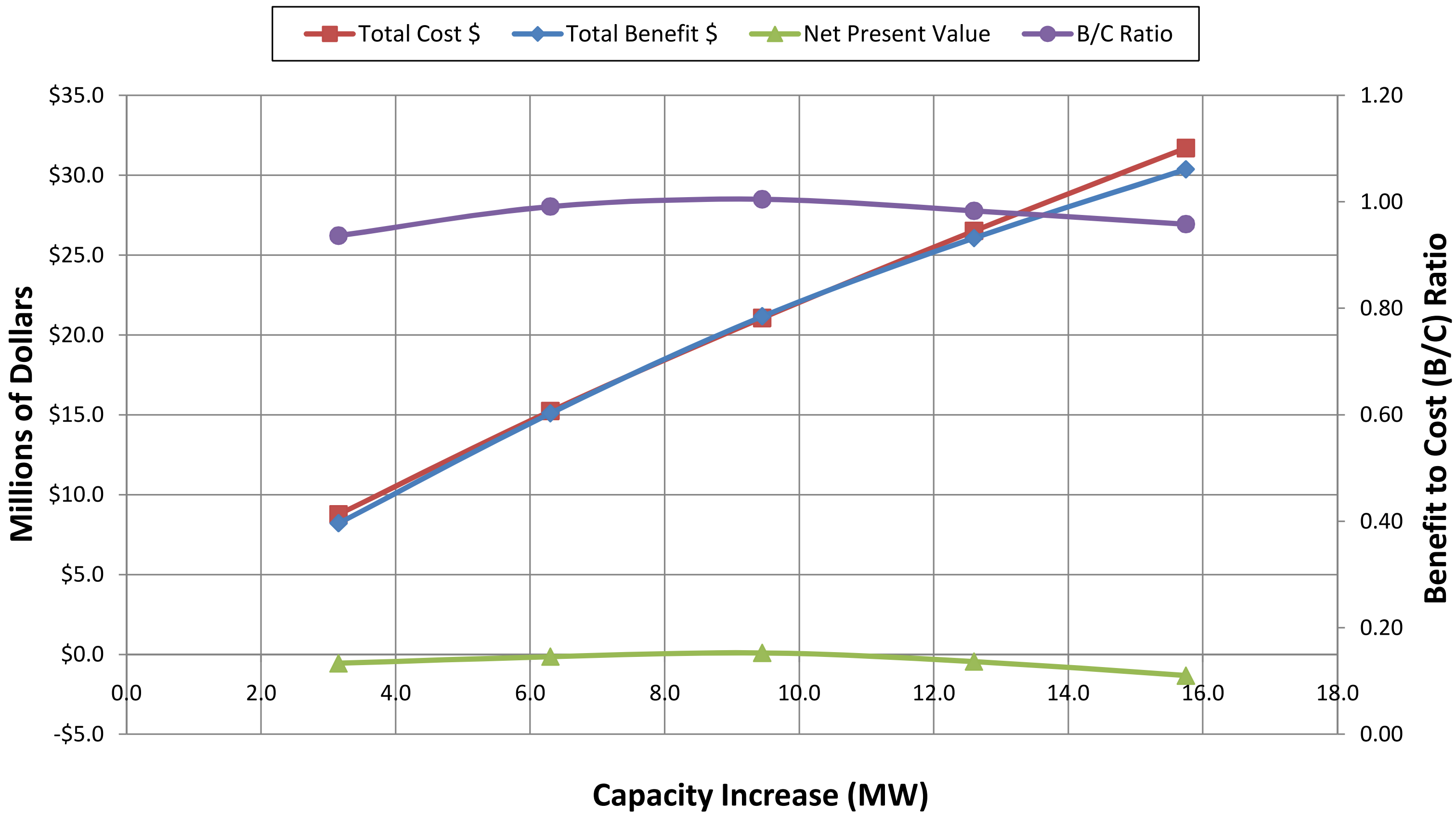
Summary of Capacity Increase Benefits and Costs
Chandler

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	1.2	594	6%	$2.8	$2,305	$4.1	$0.7	$0.6	$1.3	-$2.8	0.32
20%	2.4	606	3%	$4.8	$2,019	$7.1	$0.7	$0.9	$1.6	-$5.5	0.22
30%	3.6	606	2%	$6.7	$1,871	$9.7	$0.7	$1.1	$1.8	-$7.9	0.18
40%	4.8	606	1%	$8.5	$1,774	$12.3	$0.7	$1.4	$2.0	-$10.2	0.17
50%	6.0	606	1%	$10.2	$1,702	$14.6	$0.7	$1.6	$2.3	-$12.4	0.16



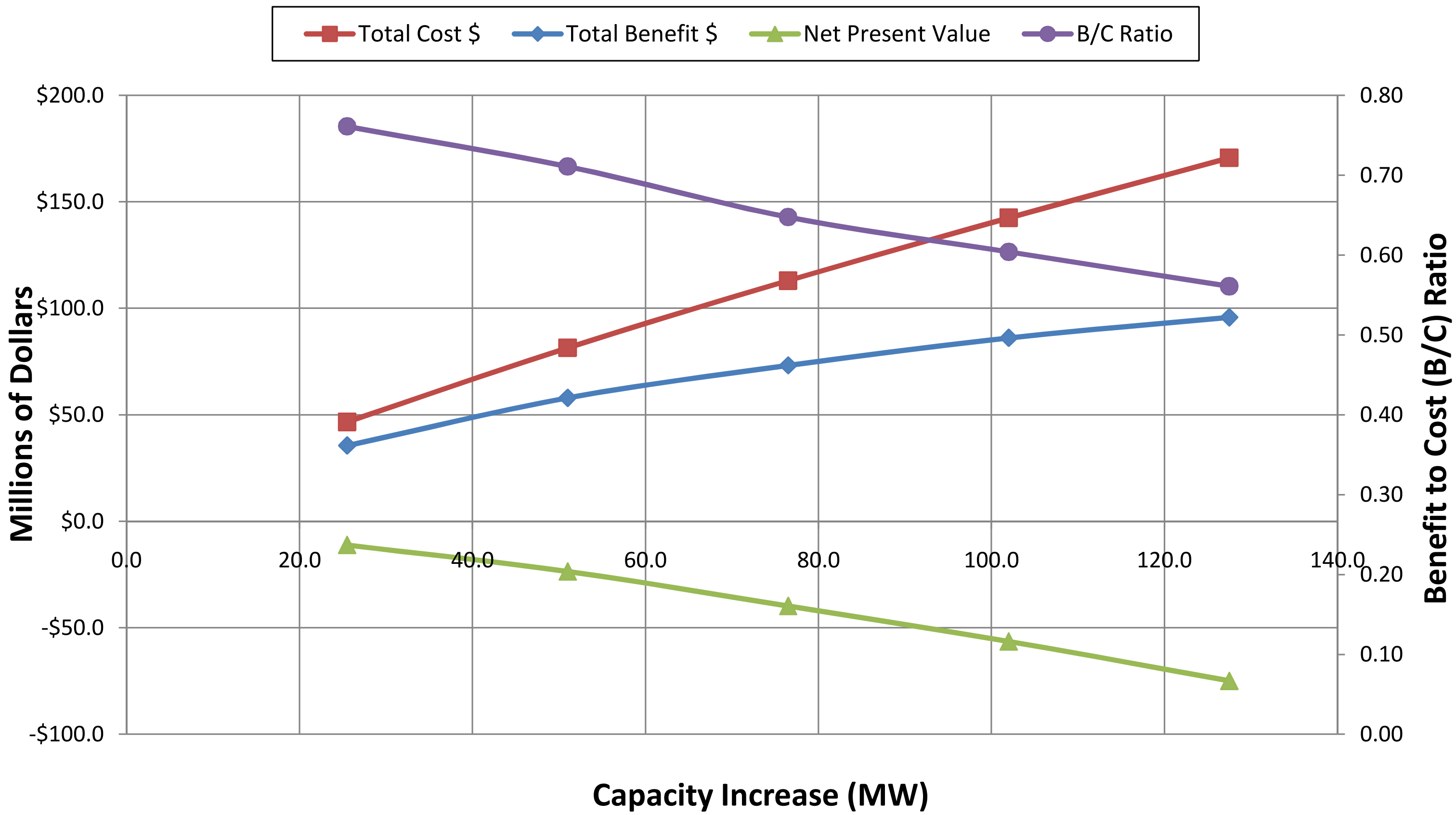
Summary of Capacity Increase Benefits and Costs
Crystal

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	3.2	4,306	16%	$6.0	$1,918	$8.8	$4.6	$3.6	$8.2	-$0.6	0.94
20%	6.3	7,862	14%	$10.6	$1,687	$15.2	$8.5	$6.6	$15.1	-$0.1	0.99
30%	9.5	10,950	13%	$14.8	$1,567	$21.1	$11.8	$9.4	$21.2	$0.1	1.00
40%	12.6	13,378	12%	$18.7	$1,487	$26.5	$14.4	$11.7	$26.1	-$0.4	0.98
50%	15.8	15,466	11%	$22.5	$1,429	$31.7	$16.6	$13.7	$30.4	-$1.3	0.96



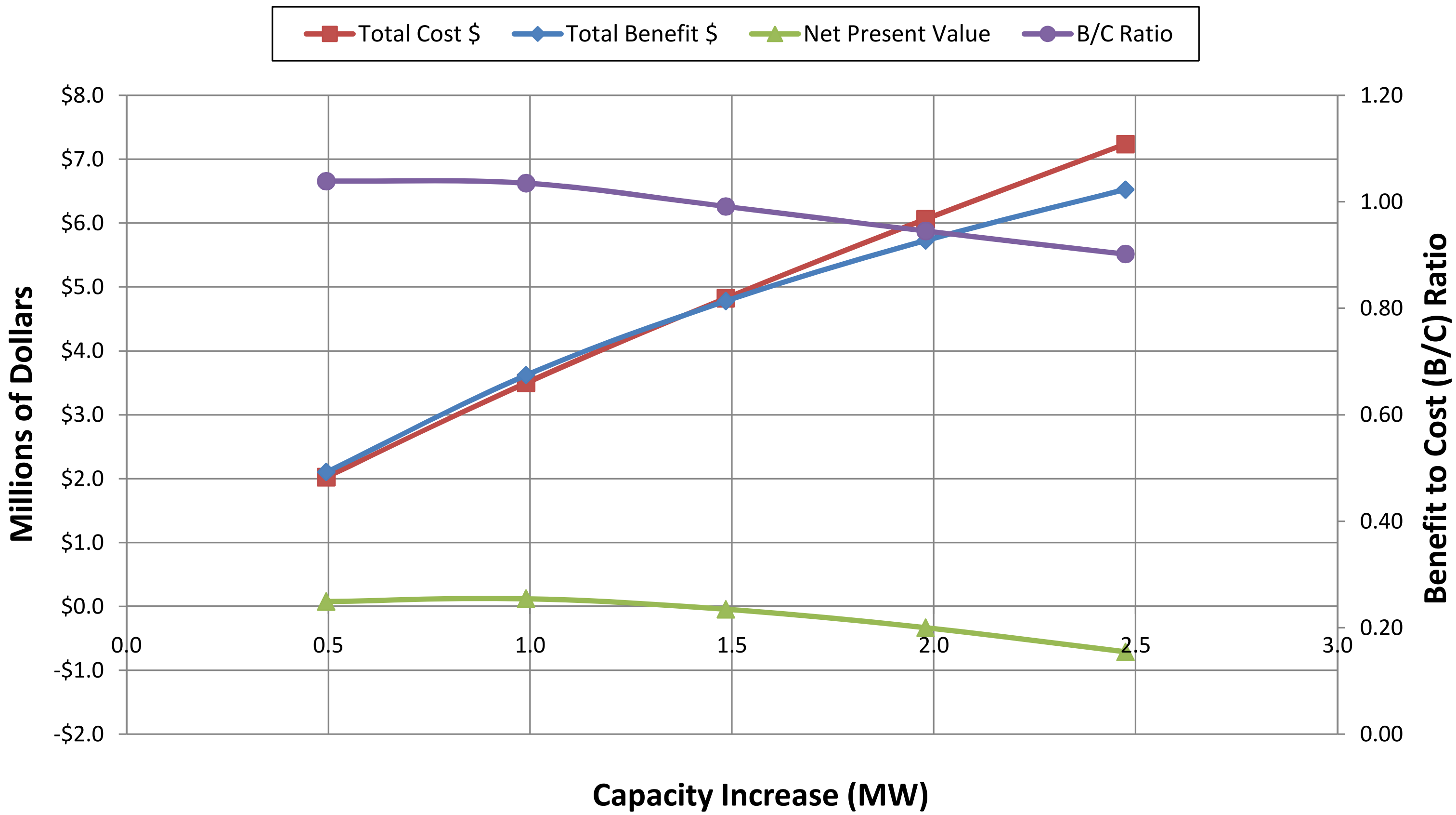
Summary of Capacity Increase Benefits and Costs
Davis

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	25.5	15,784	7%	$33.4	$1,311	$46.7	$19.6	$15.9	$35.5	-$11.1	0.76
20%	51.0	24,770	6%	$59.2	$1,161	$81.5	$30.8	$27.1	$57.9	-$23.6	0.71
30%	76.5	30,034	4%	$82.8	$1,082	$113.0	$37.3	$35.8	$73.2	-$39.8	0.65
40%	102.0	34,096	4%	$105.1	$1,030	$142.5	$42.4	$43.7	$86.1	-$56.4	0.60
50%	127.5	36,470	3%	$126.5	$992	$170.7	$45.4	$50.4	$95.7	-$74.9	0.56



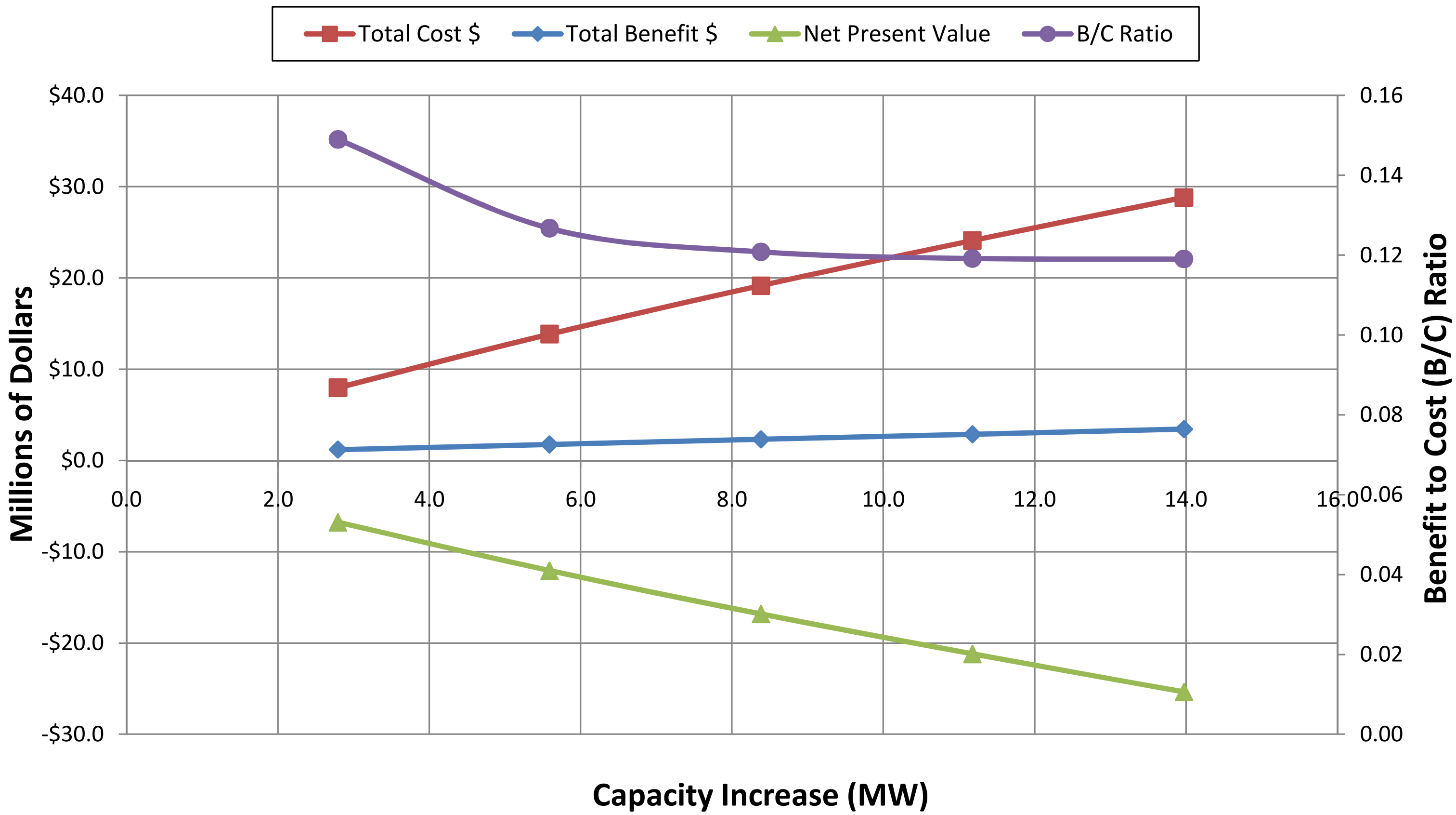
Summary of Capacity Increase Benefits and Costs
Deer Creek

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	0.5	1,120	26%	$1.4	$2,744	$2.0	$1.2	$0.9	$2.1	$0.1	1.04
20%	1.0	1,913	22%	$2.4	$2,393	$3.5	$2.1	$1.5	$3.6	$0.1	1.03
30%	1.5	2,507	19%	$3.3	$2,213	$4.8	$2.8	$2.0	$4.8	$0.0	0.99
40%	2.0	2,981	17%	$4.1	$2,094	$6.1	$3.3	$2.4	$5.7	-$0.3	0.95
50%	2.5	3,372	16%	$5.0	$2,008	$7.2	$3.7	$2.8	$6.5	-$0.7	0.90



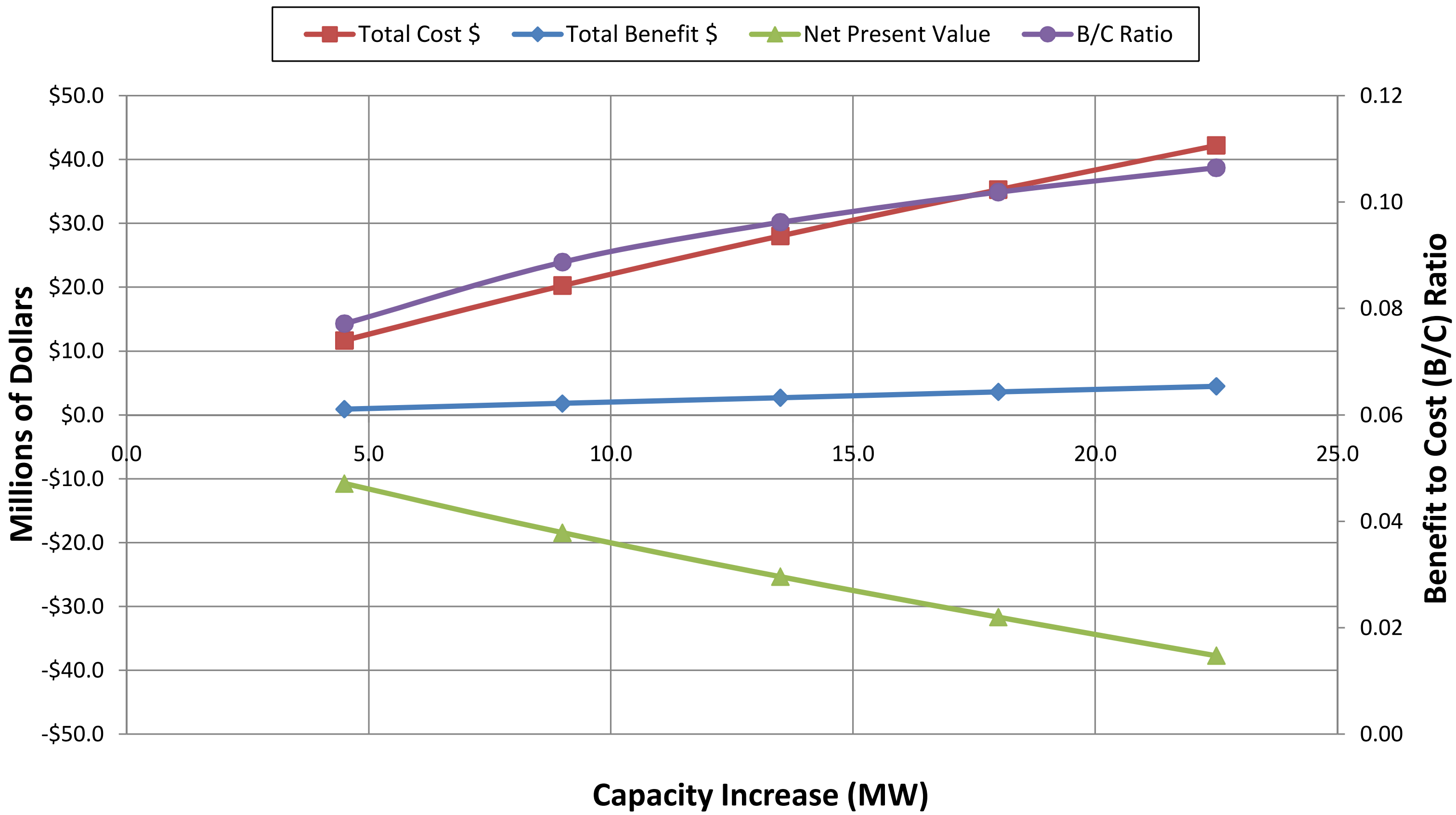
Summary of Capacity Increase Benefits and Costs
Elephant Butte

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	2.8	357	1%	$5.5	$1,962	$8.0	$0.4	$0.8	$1.2	-$6.8	0.15
20%	5.6	363	1%	$9.6	$1,725	$13.8	$0.4	$1.4	$1.8	-$12.1	0.13
30%	8.4	363	0%	$13.4	$1,601	$19.1	$0.4	$1.9	$2.3	-$16.8	0.12
40%	11.2	363	0%	$17.0	$1,520	$24.1	$0.4	$2.5	$2.9	-$21.2	0.12
50%	14.0	363	0%	$20.4	$1,460	$28.8	$0.4	$3.0	$3.4	-$25.4	0.12



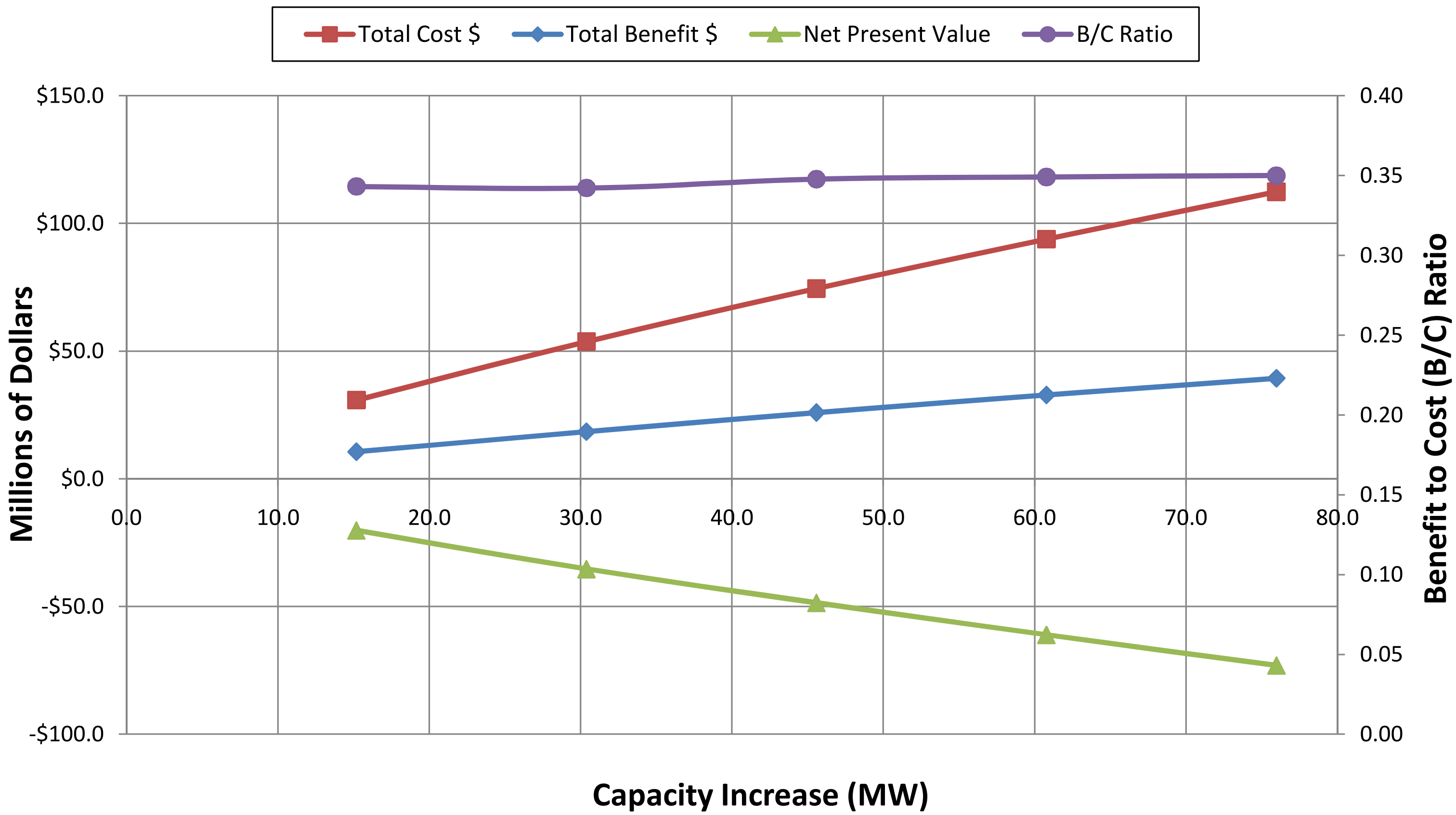
Summary of Capacity Increase Benefits and Costs
Estes

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	4.5	0	0%	$8.1	$1,795	$11.6	$0.0	$0.9	$0.9	-$10.7	0.08
20%	9.0	0	0%	$14.2	$1,581	$20.3	$0.0	$1.8	$1.8	-$18.5	0.09
30%	13.5	0	0%	$19.8	$1,469	$28.0	$0.0	$2.7	$2.7	-$25.3	0.10
40%	18.0	0	0%	$25.1	$1,395	$35.3	$0.0	$3.6	$3.6	-$31.7	0.10
50%	22.5	0	0%	$30.2	$1,341	$42.2	$0.0	$4.5	$4.5	-$37.7	0.11



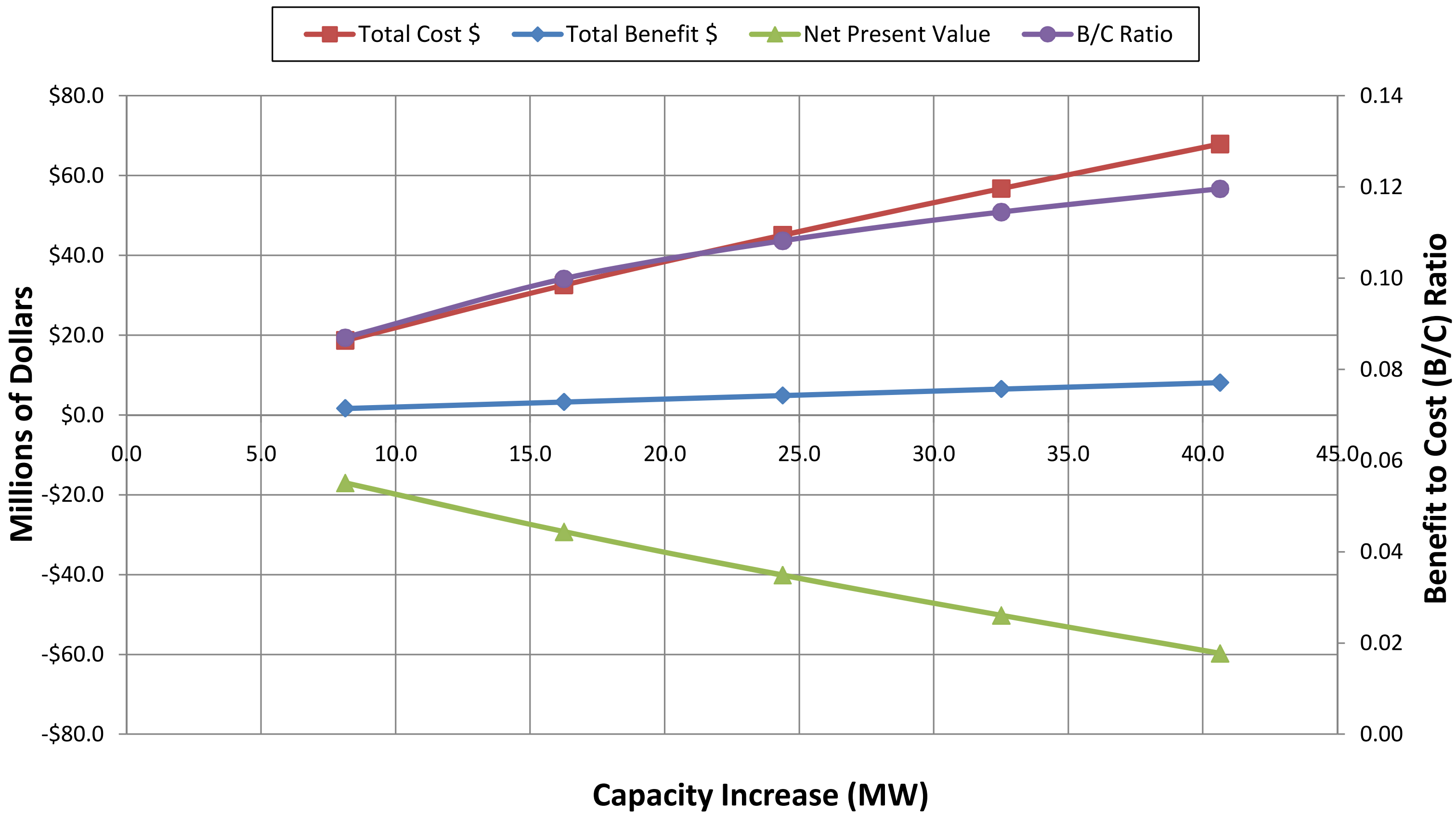
Summary of Capacity Increase Benefits and Costs
Flaming Gorge

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	15.2	4,211	3%	$21.8	$1,438	$30.8	$4.7	$5.9	$10.6	-$20.2	0.34
20%	30.4	6,881	3%	$38.6	$1,271	$53.7	$7.6	$10.8	$18.4	-$35.3	0.34
30%	45.6	9,378	2%	$54.0	$1,184	$74.4	$10.4	$15.5	$25.9	-$48.6	0.35
40%	60.8	11,526	2%	$68.5	$1,126	$93.8	$12.7	$20.0	$32.8	-$61.1	0.35
50%	76.0	13,495	2%	$82.3	$1,084	$112.3	$14.9	$24.4	$39.3	-$73.0	0.35



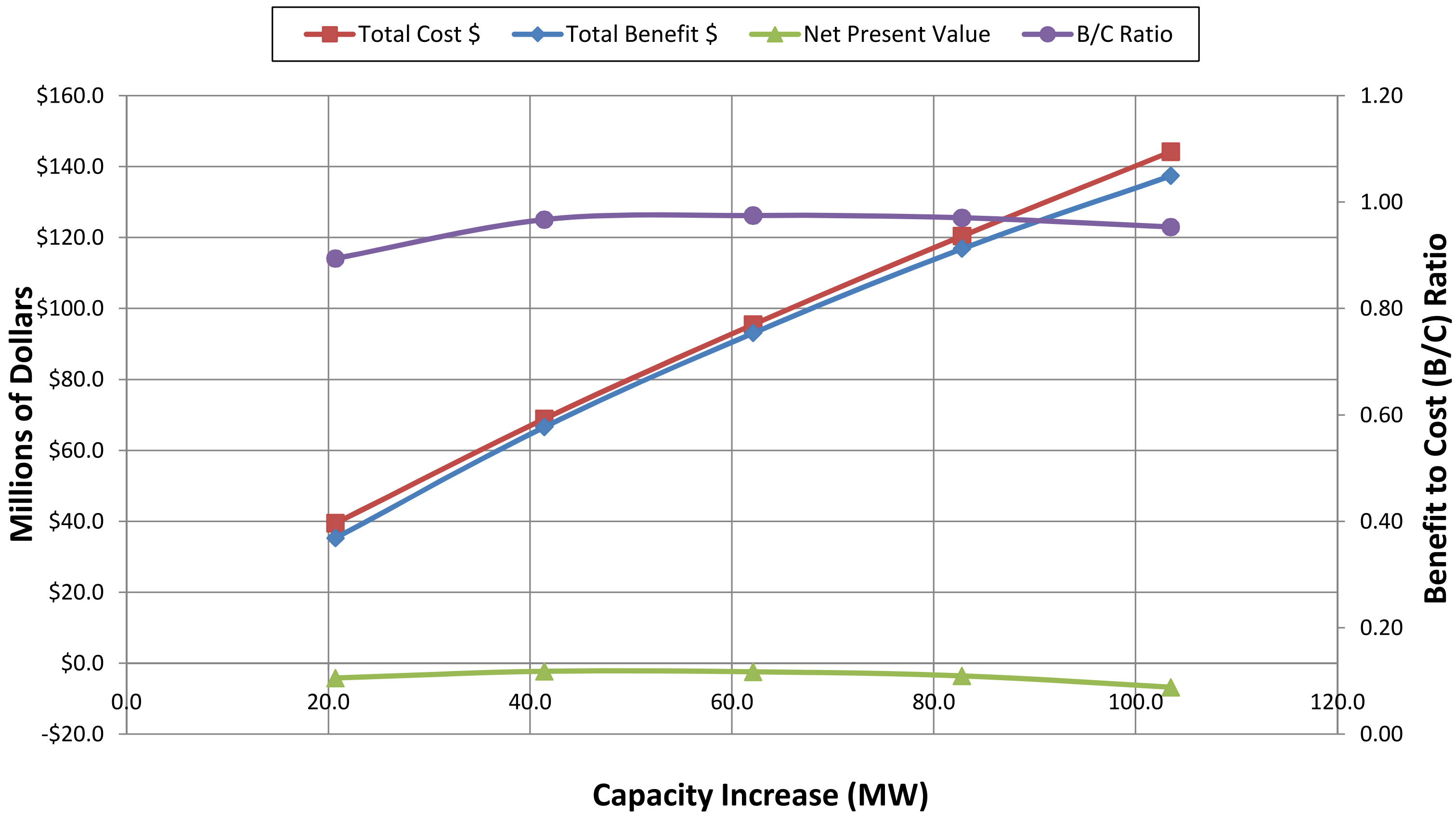
Summary of Capacity Increase Benefits and Costs
Flatiron

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	8.1	0	0%	$13.1	$1,610	$18.7	$0.0	$1.6	$1.6	-$17.0	0.09
20%	16.3	0	0%	$23.1	$1,421	$32.5	$0.0	$3.2	$3.2	-$29.3	0.10
30%	24.4	0	0%	$32.2	$1,322	$45.0	$0.0	$4.9	$4.9	-$40.1	0.11
40%	32.5	0	0%	$40.8	$1,256	$56.7	$0.0	$6.5	$6.5	-$50.2	0.11
50%	40.6	0	0%	$49.1	$1,208	$67.9	$0.0	$8.1	$8.1	-$59.7	0.12



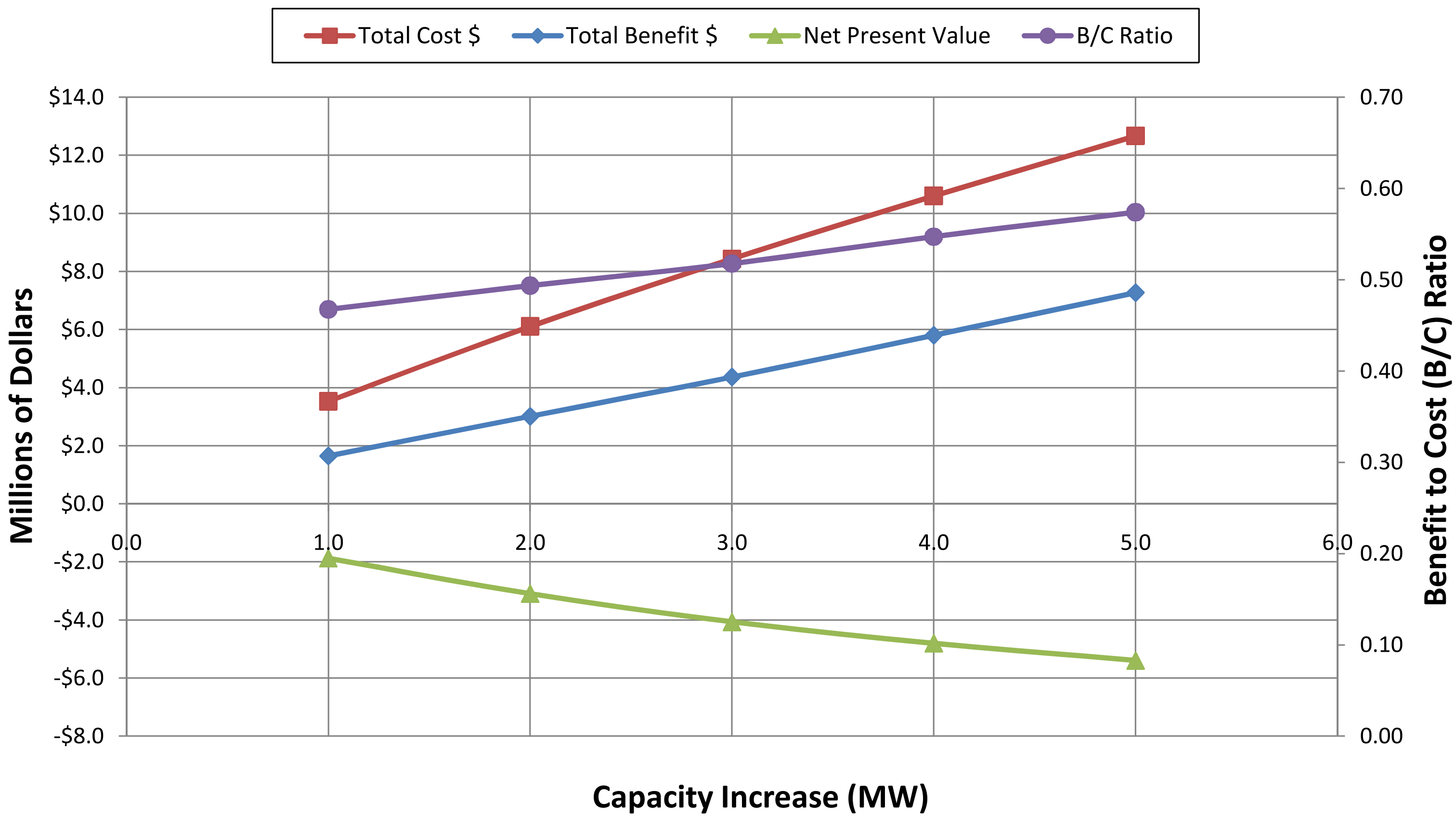
Summary of Capacity Increase Benefits and Costs
Folsom

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	20.7	12,591	7%	$28.2	$1,361	$39.5	$22.5	$12.7	$35.3	-$4.2	0.89
20%	41.4	23,579	7%	$49.8	$1,204	$68.9	$42.2	$24.4	$66.6	-$2.3	0.97
30%	62.1	32,607	6%	$69.7	$1,122	$95.5	$58.4	$34.7	$93.1	-$2.4	0.97
40%	82.8	40,555	6%	$88.4	$1,068	$120.4	$72.6	$44.3	$116.8	-$3.6	0.97
50%	103.5	47,195	5%	$106.4	$1,028	$144.2	$84.5	$52.9	$137.4	-$6.8	0.95



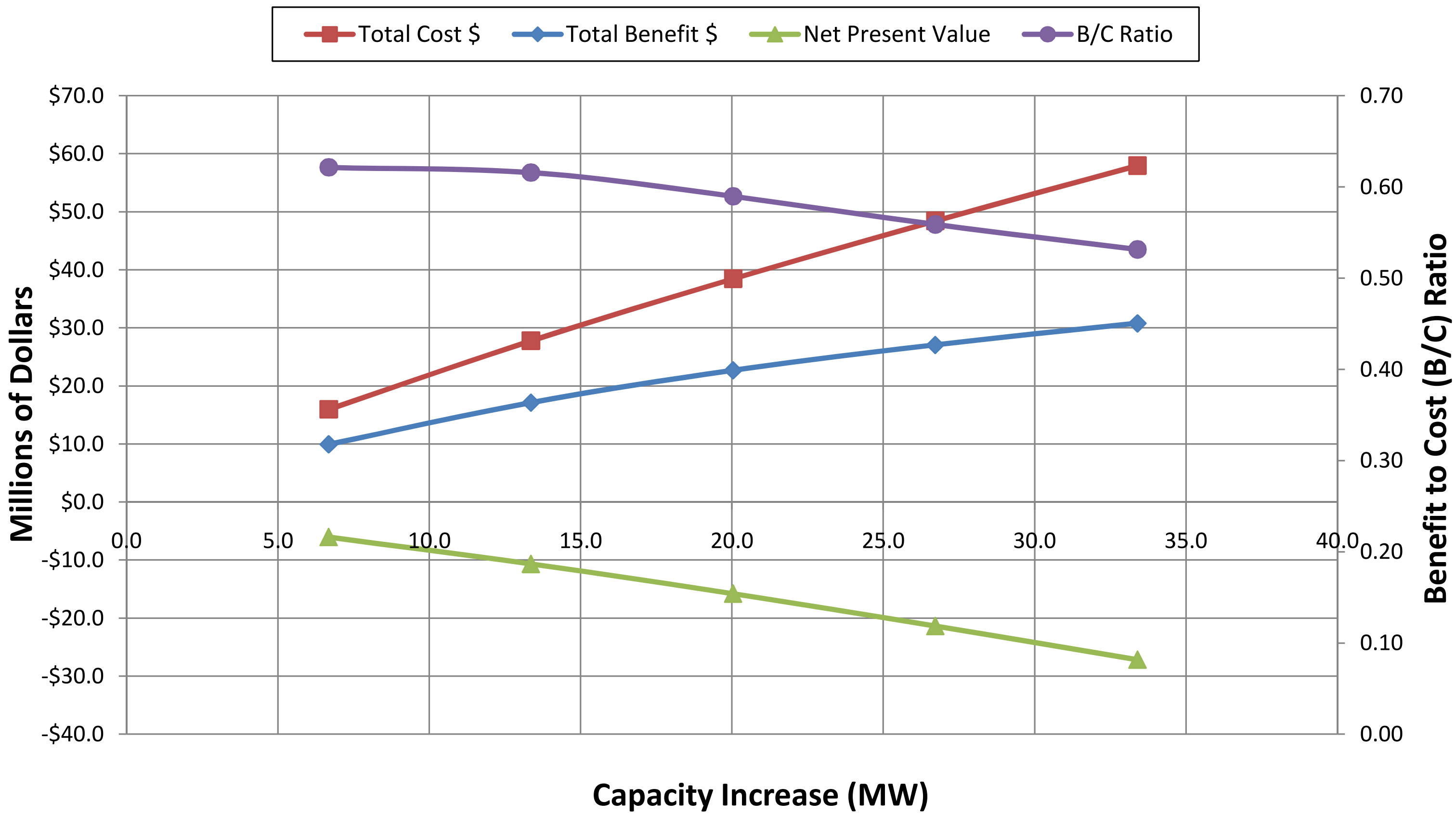
Summary of Capacity Increase Benefits and Costs
Fontenelle

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	1.0	884	10%	$2.4	$2,388	$3.5	$0.8	$0.8	$1.6	-$1.9	0.47
20%	2.0	1,595	9%	$4.2	$2,090	$6.1	$1.5	$1.5	$3.0	-$3.1	0.49
30%	3.0	2,296	9%	$5.8	$1,936	$8.4	$2.2	$2.2	$4.4	-$4.1	0.52
40%	4.0	3,050	9%	$7.3	$1,835	$10.6	$2.9	$2.9	$5.8	-$4.8	0.55
50%	5.0	3,824	9%	$8.8	$1,760	$12.7	$3.7	$3.6	$7.3	-$5.4	0.57



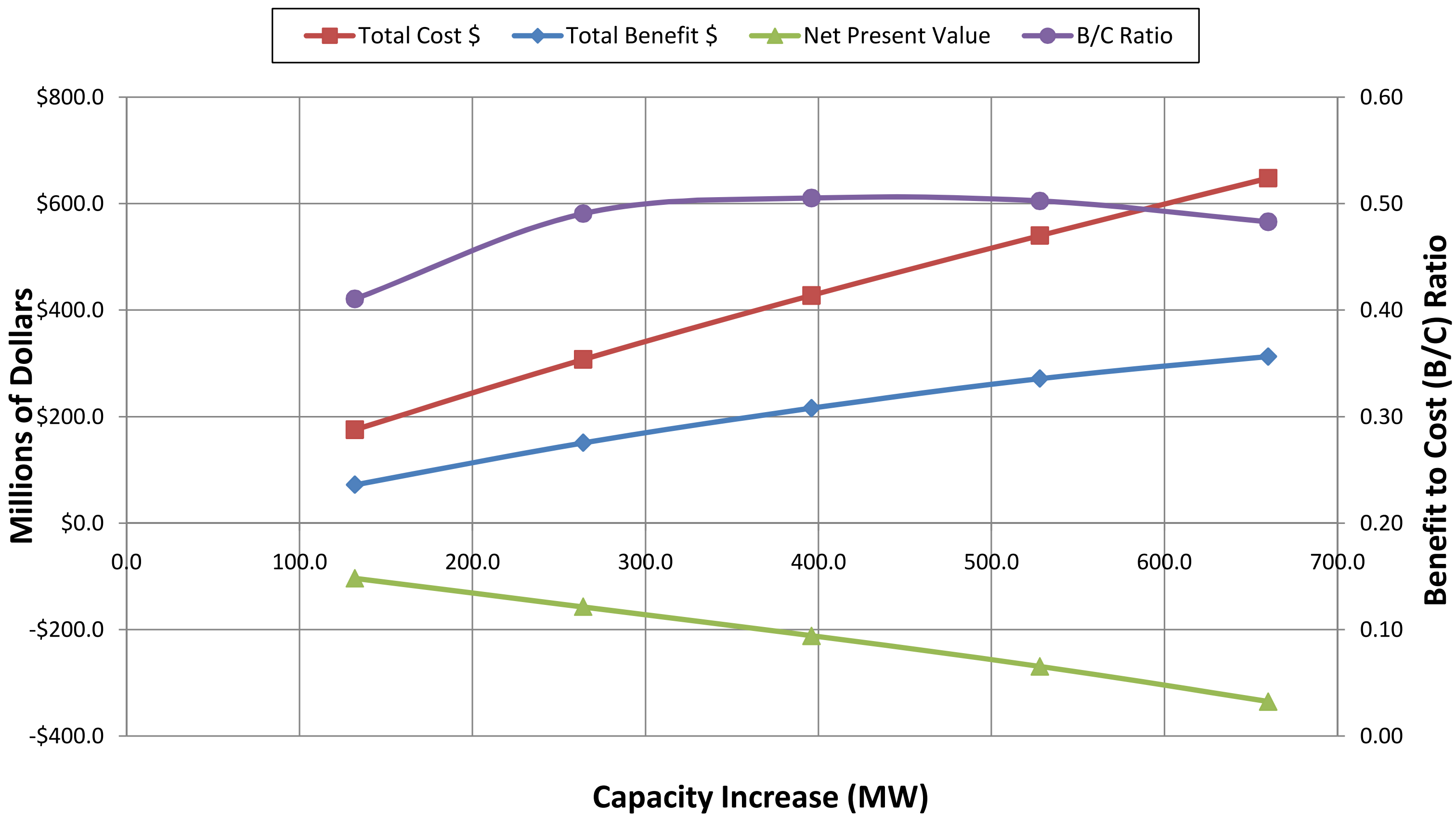
Summary of Capacity Increase Benefits and Costs
Fremont Canyon

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	6.7	4,831	8%	$11.1	$1,669	$16.0	$5.3	$4.6	$9.9	-$6.0	0.62
20%	13.4	8,128	7%	$19.7	$1,472	$27.8	$8.9	$8.2	$17.1	-$10.7	0.62
30%	20.0	10,512	6%	$27.4	$1,369	$38.5	$11.5	$11.2	$22.7	-$15.8	0.59
40%	26.7	12,231	5%	$34.7	$1,300	$48.4	$13.4	$13.7	$27.1	-$21.4	0.56
50%	33.4	13,583	5%	$41.8	$1,250	$58.0	$14.8	$16.0	$30.8	-$27.2	0.53



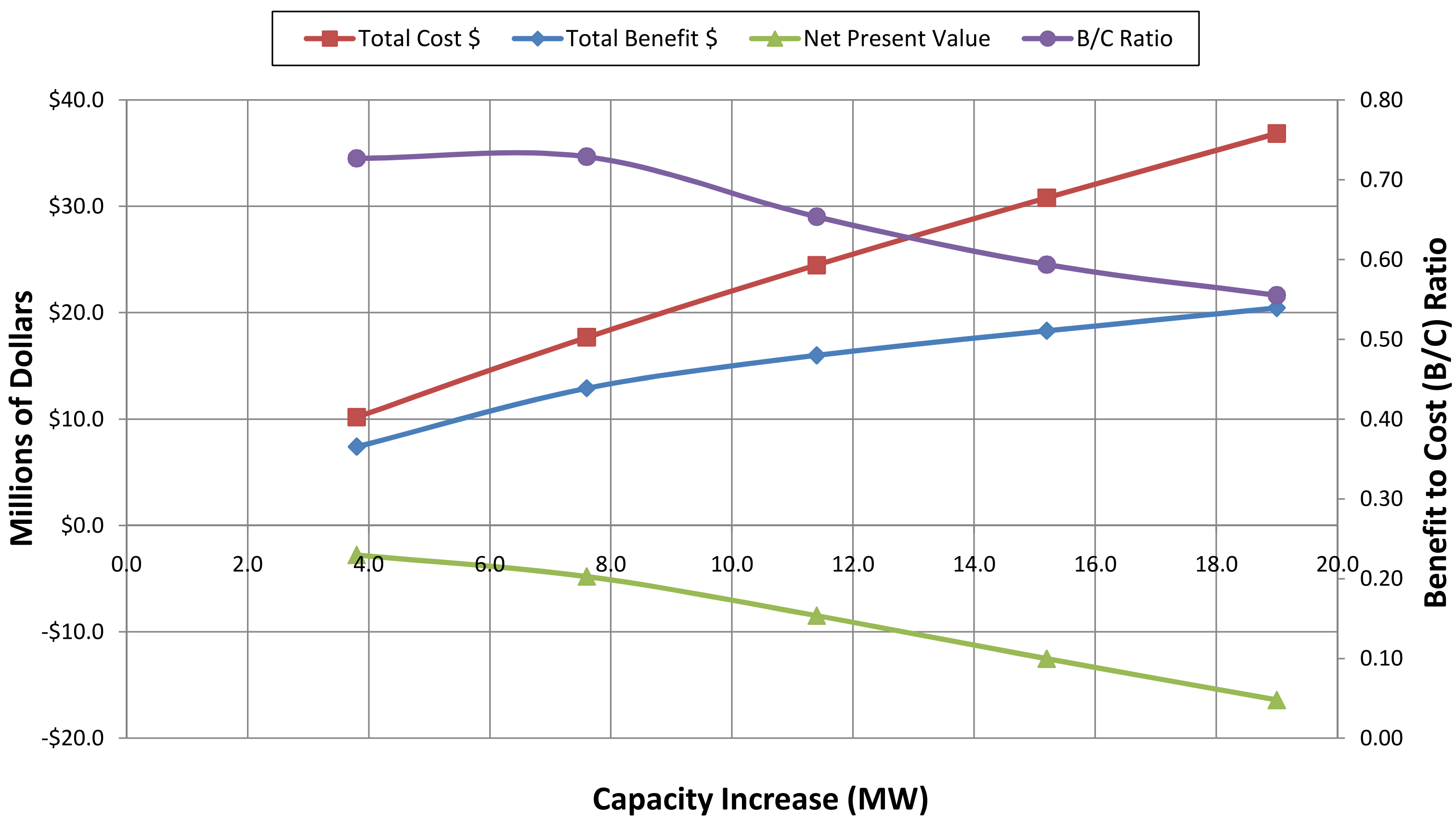
Summary of Capacity Increase Benefits and Costs
Glen Canyon

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	132.0	23,719	2%	$130.2	$986	$175.5	$29.5	$42.6	$72.1	-$103.4	0.41
20%	264.0	50,969	2%	$231.7	$878	$307.7	$63.4	$87.5	$150.9	-$156.7	0.49
30%	396.0	71,082	2%	$324.9	$820	$427.6	$88.4	$127.6	$216.0	-$211.5	0.51
40%	528.0	86,174	2%	$413.2	$783	$540.3	$107.2	$164.3	$271.5	-$268.8	0.50
50%	660.0	94,012	2%	$498.0	$755	$647.9	$116.9	$196.0	$312.9	-$334.9	0.48



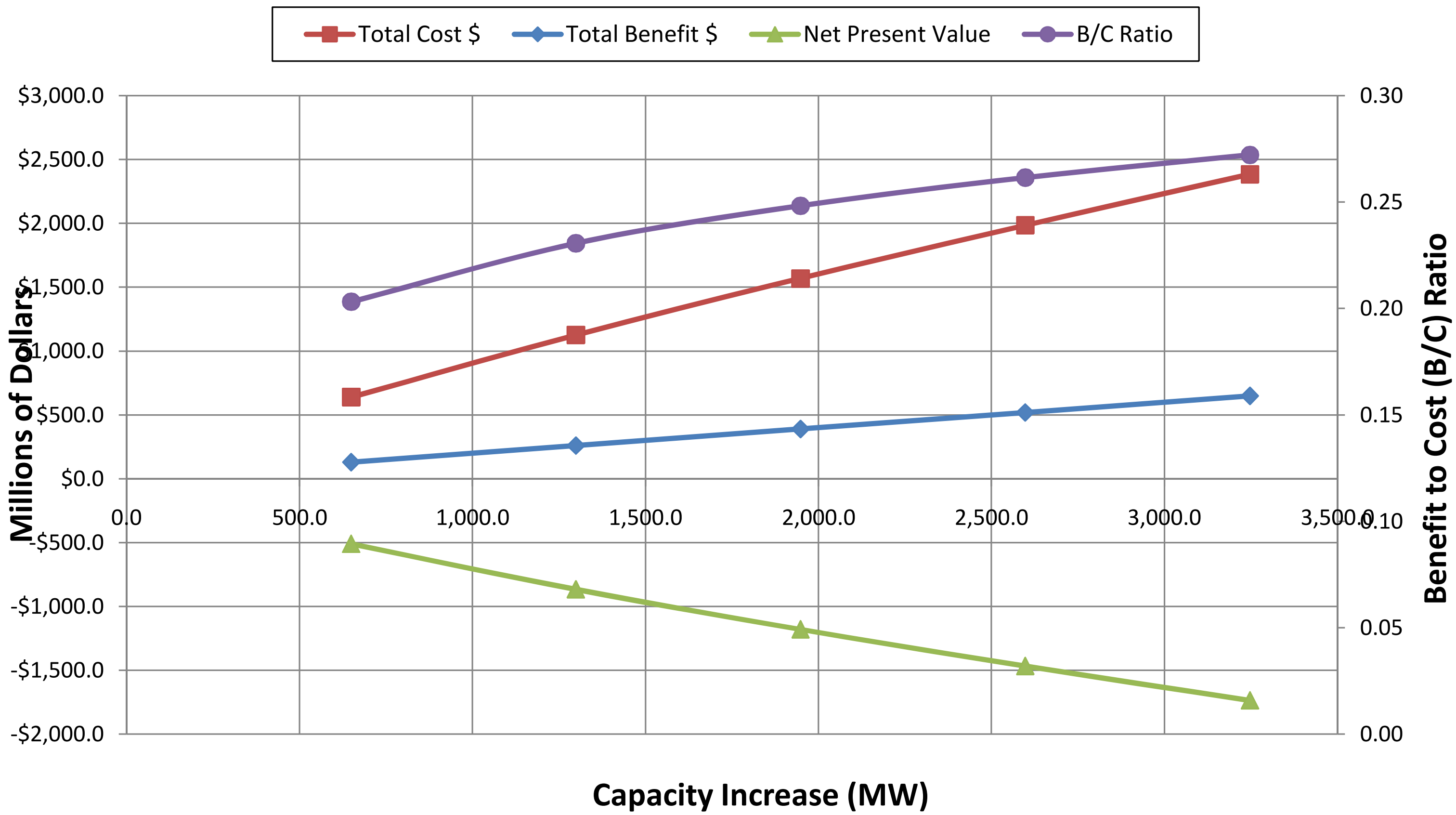
Summary of Capacity Increase Benefits and Costs
Glendo

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	3.8	4,425	13%	$7.0	$1,852	$10.2	$3.6	$3.8	$7.4	-$2.8	0.73
20%	7.6	7,585	11%	$12.4	$1,630	$17.7	$6.2	$6.7	$12.9	-$4.8	0.73
30%	11.4	9,144	9%	$17.3	$1,514	$24.5	$7.5	$8.5	$16.0	-$8.5	0.65
40%	15.2	10,169	8%	$21.9	$1,438	$30.8	$8.3	$10.0	$18.3	-$12.5	0.59
50%	19.0	11,105	7%	$26.2	$1,382	$36.8	$9.1	$11.4	$20.5	-$16.4	0.56



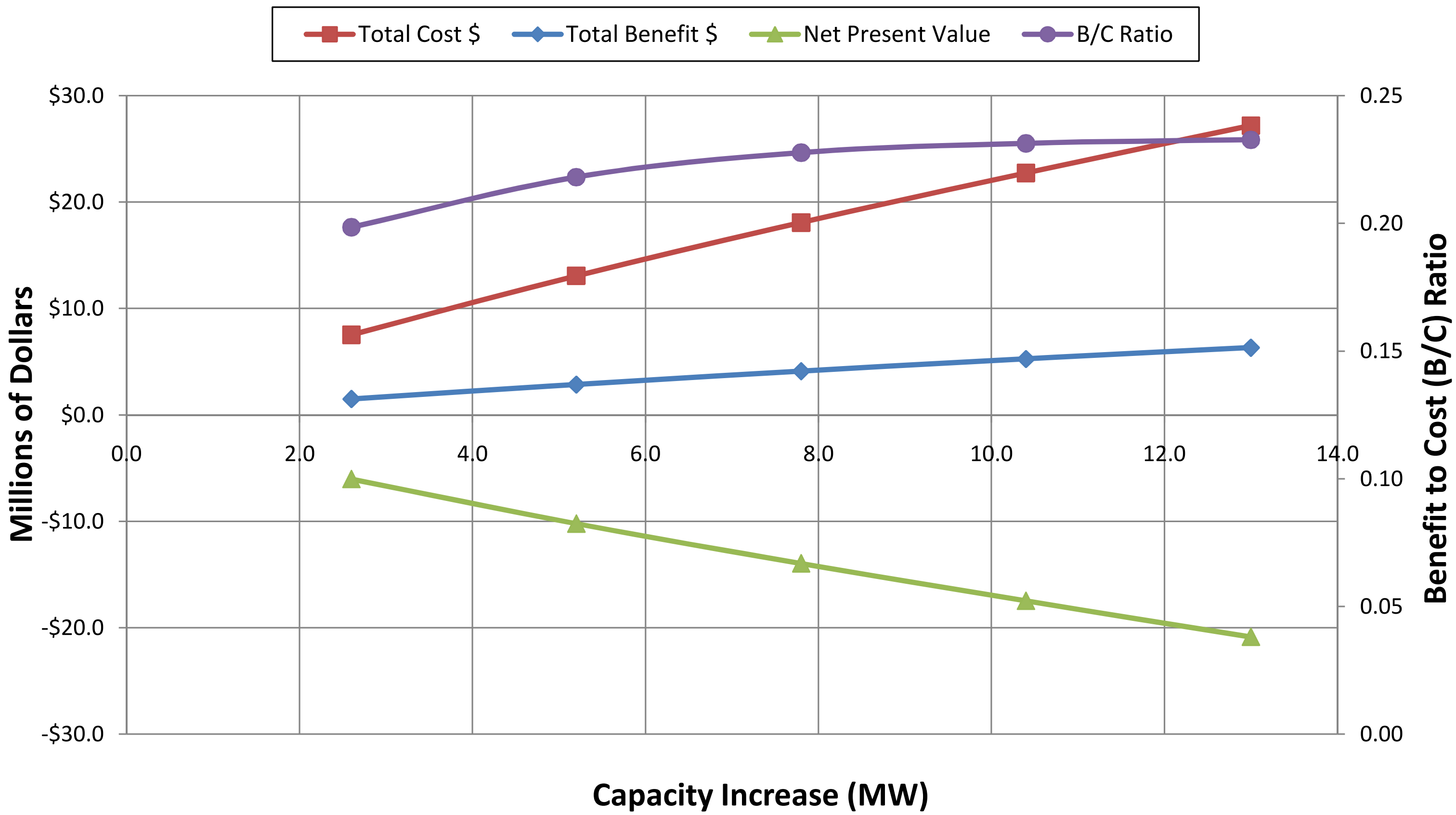
Summary of Capacity Increase Benefits and Costs
Grand Coulee

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	649.5	141	0%	$491.4	$757	$639.5	$0.2	$129.8	$129.9	-$509.5	0.20
20%	1,299.0	141	0%	$878.8	$676	$1,125.5	$0.2	$259.4	$259.6	-$865.9	0.23
30%	1,948.5	141	0%	$1,236.0	$634	$1,568.0	$0.2	$389.1	$389.2	-$1,178.8	0.25
40%	2,598.0	141	0%	$1,575.1	$606	$1,984.7	$0.2	$518.7	$518.9	-$1,465.8	0.26
50%	3,247.5	141	0%	$1,901.5	$586	$2,383.3	$0.2	$648.4	$648.5	-$1,734.8	0.27



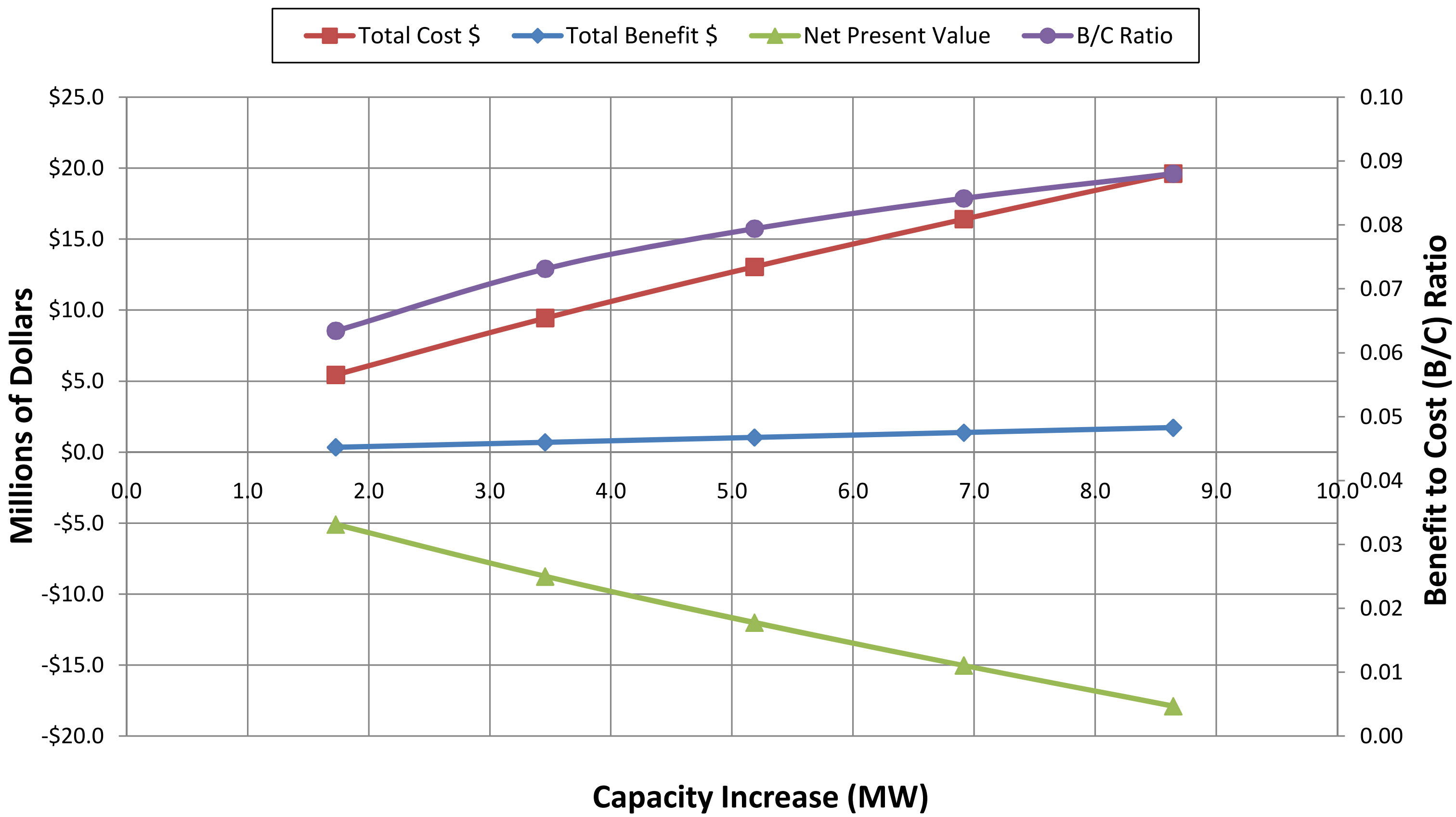
Summary of Capacity Increase Benefits and Costs
Green Mountain

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	2.6	540	2%	$5.2	$1,989	$7.5	$0.6	$0.9	$1.5	-$6.0	0.20
20%	5.2	1,003	2%	$9.1	$1,748	$13.1	$1.1	$1.7	$2.8	-$10.2	0.22
30%	7.8	1,415	2%	$12.7	$1,622	$18.1	$1.6	$2.5	$4.1	-$14.0	0.23
40%	10.4	1,762	2%	$16.0	$1,540	$22.7	$2.0	$3.3	$5.3	-$17.5	0.23
50%	13.0	2,065	2%	$19.2	$1,479	$27.2	$2.3	$4.0	$6.3	-$20.9	0.23



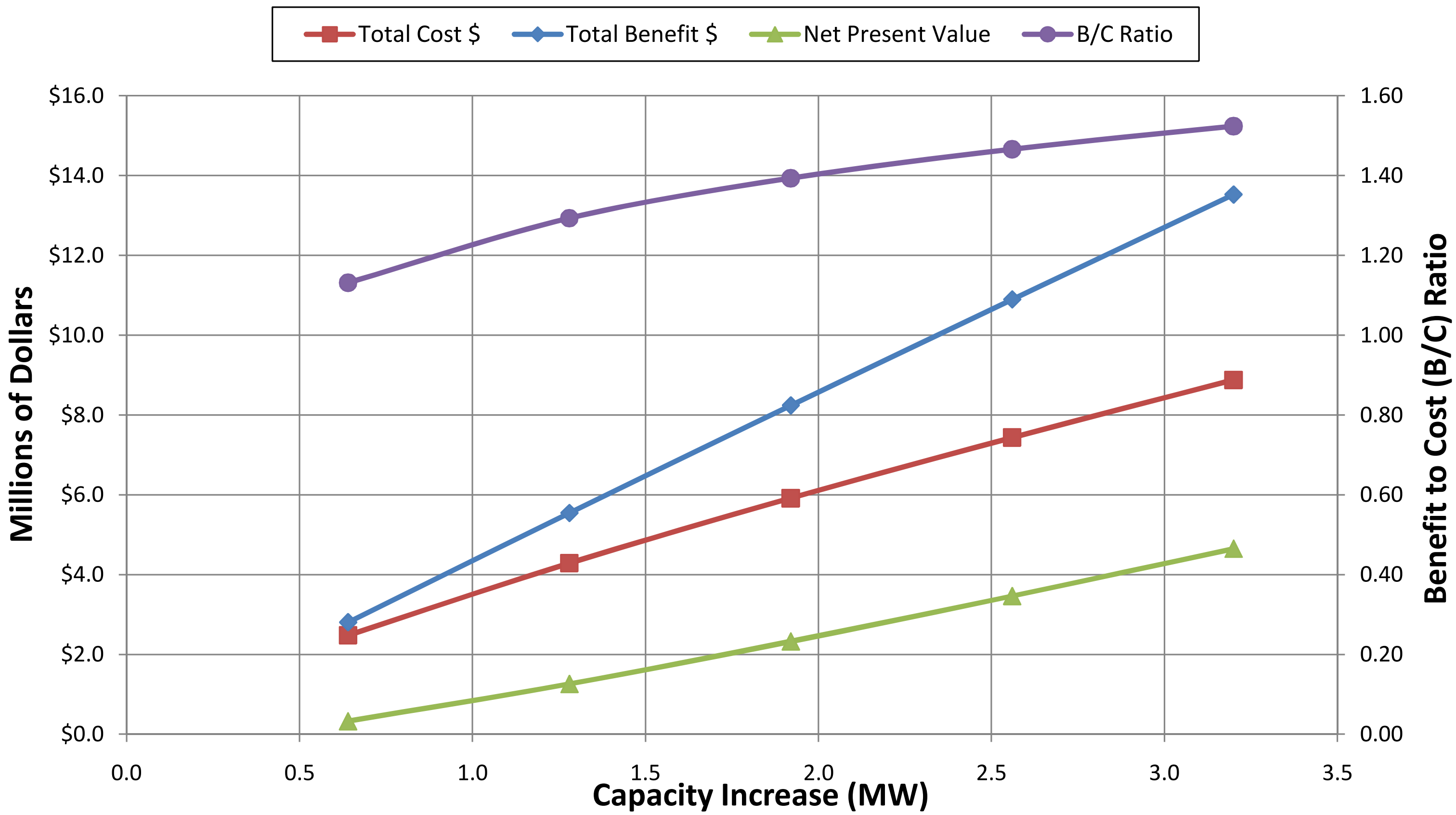
Summary of Capacity Increase Benefits and Costs
Green Springs

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	1.7	0	0%	$3.7	$2,149	$5.4	$0.0	$0.3	$0.3	-$5.1	0.06
20%	3.5	0	0%	$6.5	$1,885	$9.4	$0.0	$0.7	$0.7	-$8.8	0.07
30%	5.2	0	0%	$9.1	$1,748	$13.0	$0.0	$1.0	$1.0	-$12.0	0.08
40%	6.9	0	0%	$11.5	$1,658	$16.4	$0.0	$1.4	$1.4	-$15.0	0.08
50%	8.6	0	0%	$13.8	$1,592	$19.6	$0.0	$1.7	$1.7	-$17.9	0.09



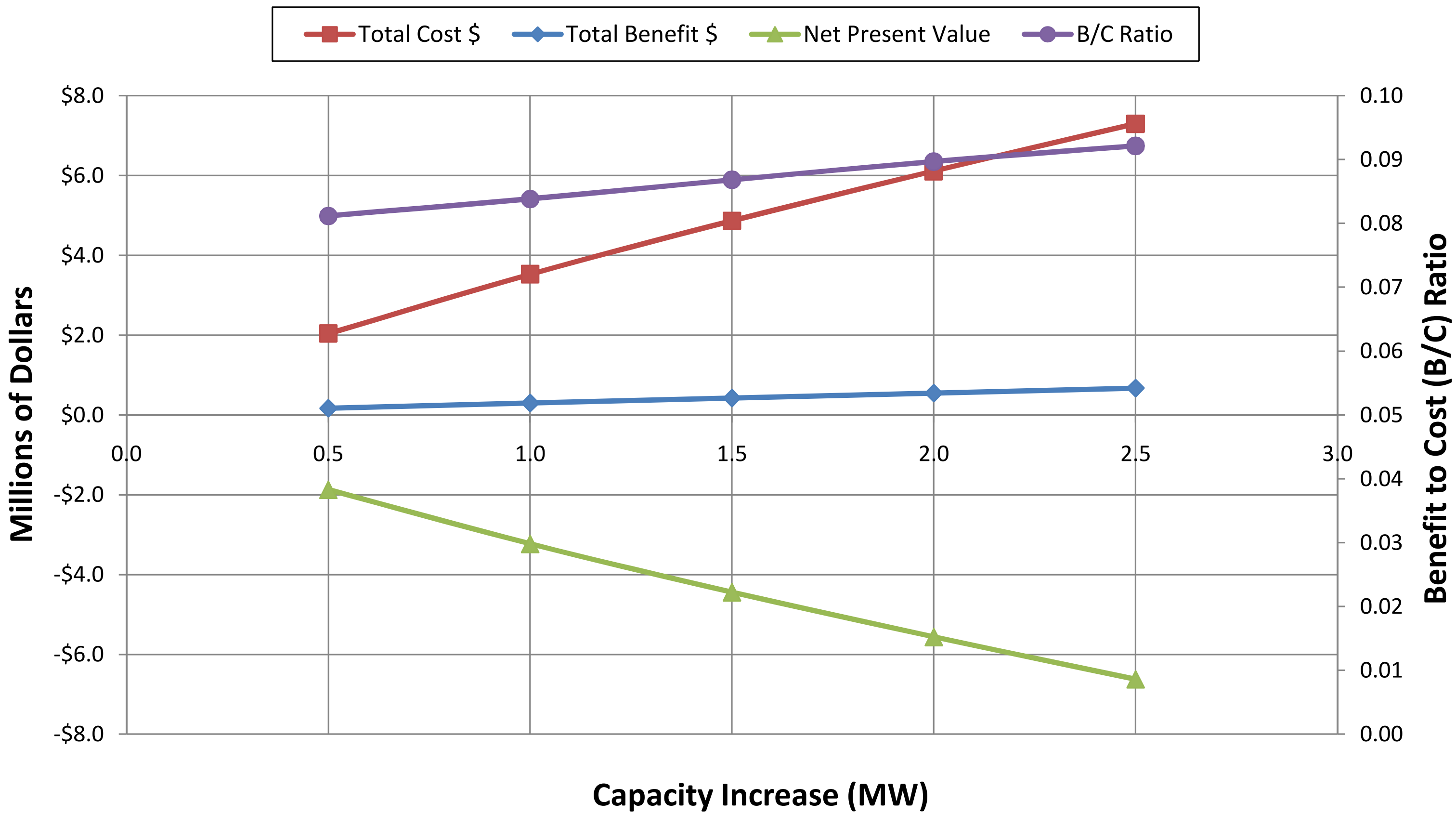
Summary of Capacity Increase Benefits and Costs
Guernsey

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	0.6	1,830	33%	$1.7	$2,607	$2.5	$1.5	$1.3	$2.8	$0.3	1.13
20%	1.3	3,599	32%	$2.9	$2,277	$4.3	$2.9	$2.6	$5.5	$1.3	1.29
30%	1.9	5,325	32%	$4.0	$2,107	$5.9	$4.3	$3.9	$8.2	$2.3	1.39
40%	2.6	7,011	31%	$5.1	$1,995	$7.4	$5.7	$5.2	$10.9	$3.5	1.47
50%	3.2	8,673	31%	$6.1	$1,913	$8.9	$7.1	$6.4	$13.5	$4.6	1.52



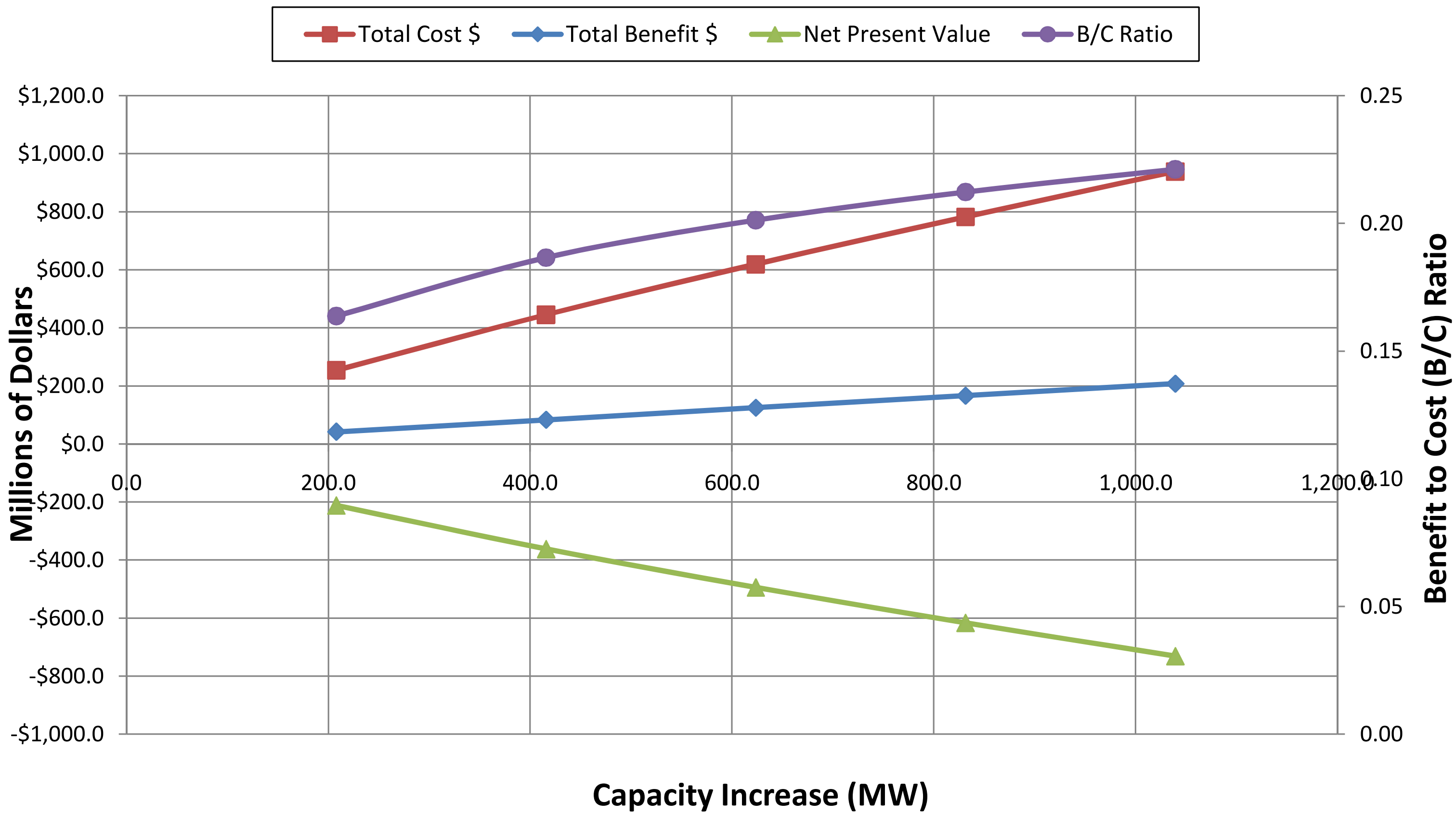
Summary of Capacity Increase Benefits and Costs
Heart Mountain

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	0.5	40	1%	$1.4	$2,739	$2.0	$0.0	$0.1	$0.2	-$1.9	0.08
20%	1.0	58	1%	$2.4	$2,388	$3.5	$0.1	$0.2	$0.3	-$3.2	0.08
30%	1.5	75	1%	$3.3	$2,208	$4.9	$0.1	$0.4	$0.4	-$4.4	0.09
40%	2.0	90	1%	$4.2	$2,090	$6.1	$0.1	$0.5	$0.5	-$5.6	0.09
50%	2.5	105	0%	$5.0	$2,004	$7.3	$0.1	$0.6	$0.7	-$6.6	0.09



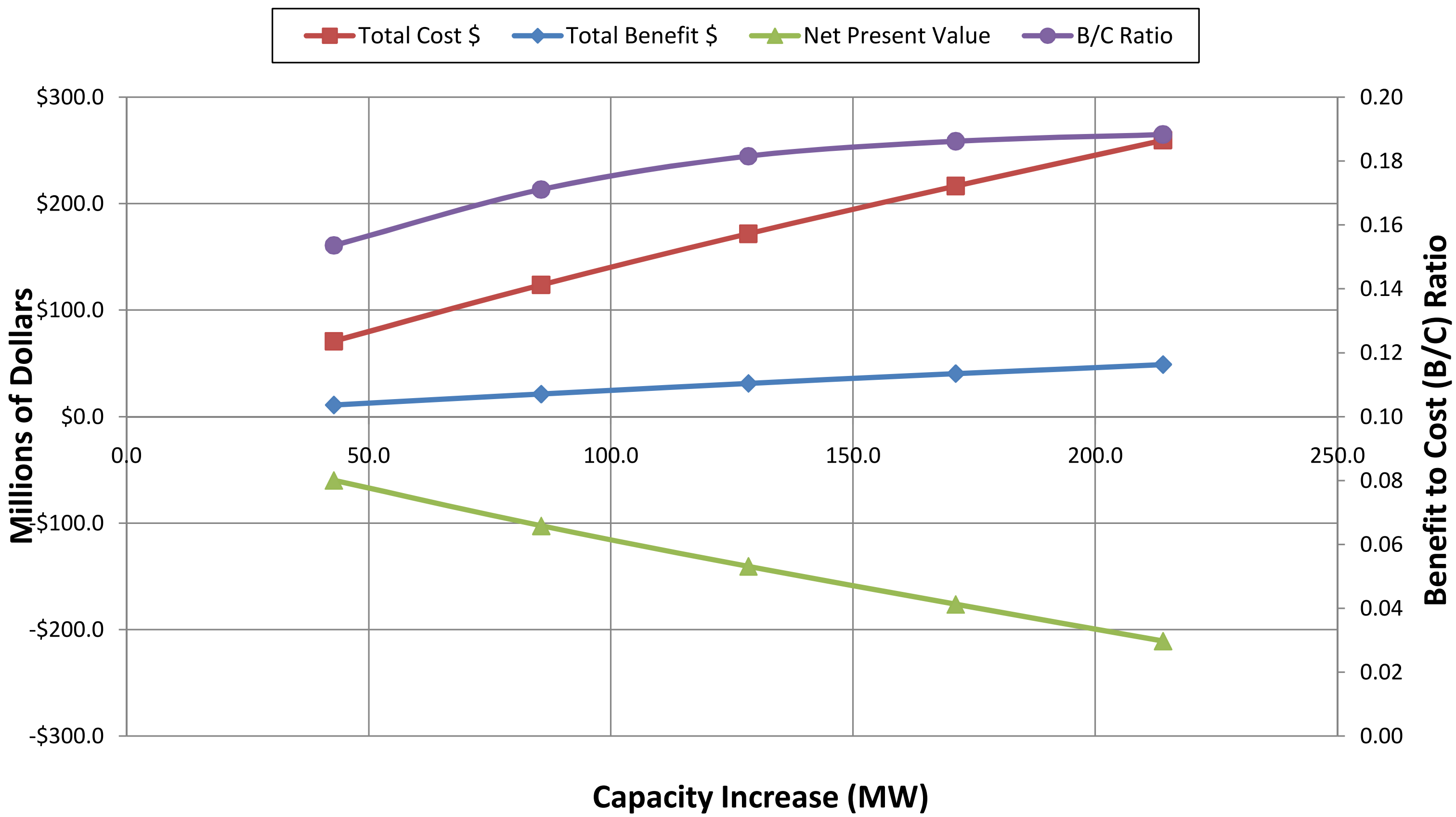
Summary of Capacity Increase Benefits and Costs
Hoover

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	207.9	0	0%	$189.9	$913	$253.5	$0.0	$41.5	$41.5	-$212.0	0.16
20%	415.8	0	0%	$338.4	$814	$444.8	$0.0	$83.0	$83.0	-$361.8	0.19
30%	623.6	0	0%	$474.9	$762	$618.6	$0.0	$124.5	$124.5	-$494.2	0.20
40%	831.5	0	0%	$604.3	$727	$782.0	$0.0	$166.0	$166.0	-$616.0	0.21
50%	1,039.4	0	0%	$728.7	$701	$938.2	$0.0	$207.5	$207.5	-$730.7	0.22



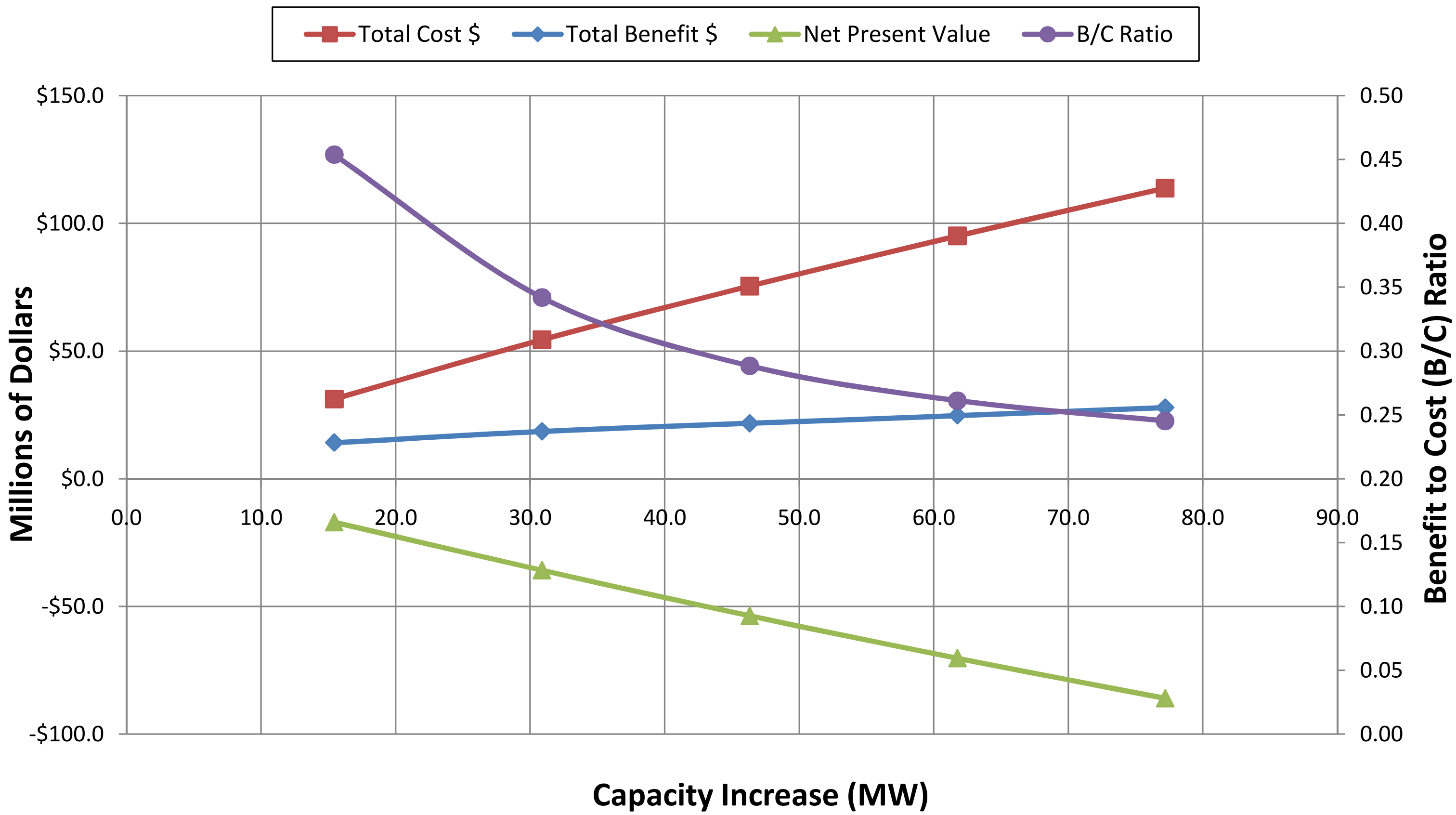
Summary of Capacity Increase Benefits and Costs
Hungry Horse

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	42.8	1,198	0%	$51.2	$1,197	$70.7	$1.5	$9.4	$10.9	-$59.9	0.15
20%	85.6	2,103	0%	$90.9	$1,062	$123.7	$2.6	$18.5	$21.2	-$102.5	0.17
30%	128.4	2,850	0%	$127.2	$991	$171.6	$3.6	$27.6	$31.2	-$140.5	0.18
40%	171.2	3,173	0%	$161.5	$944	$216.6	$4.0	$36.3	$40.3	-$176.3	0.19
50%	214.0	3,173	0%	$194.5	$909	$259.5	$4.0	$44.9	$48.9	-$210.6	0.19



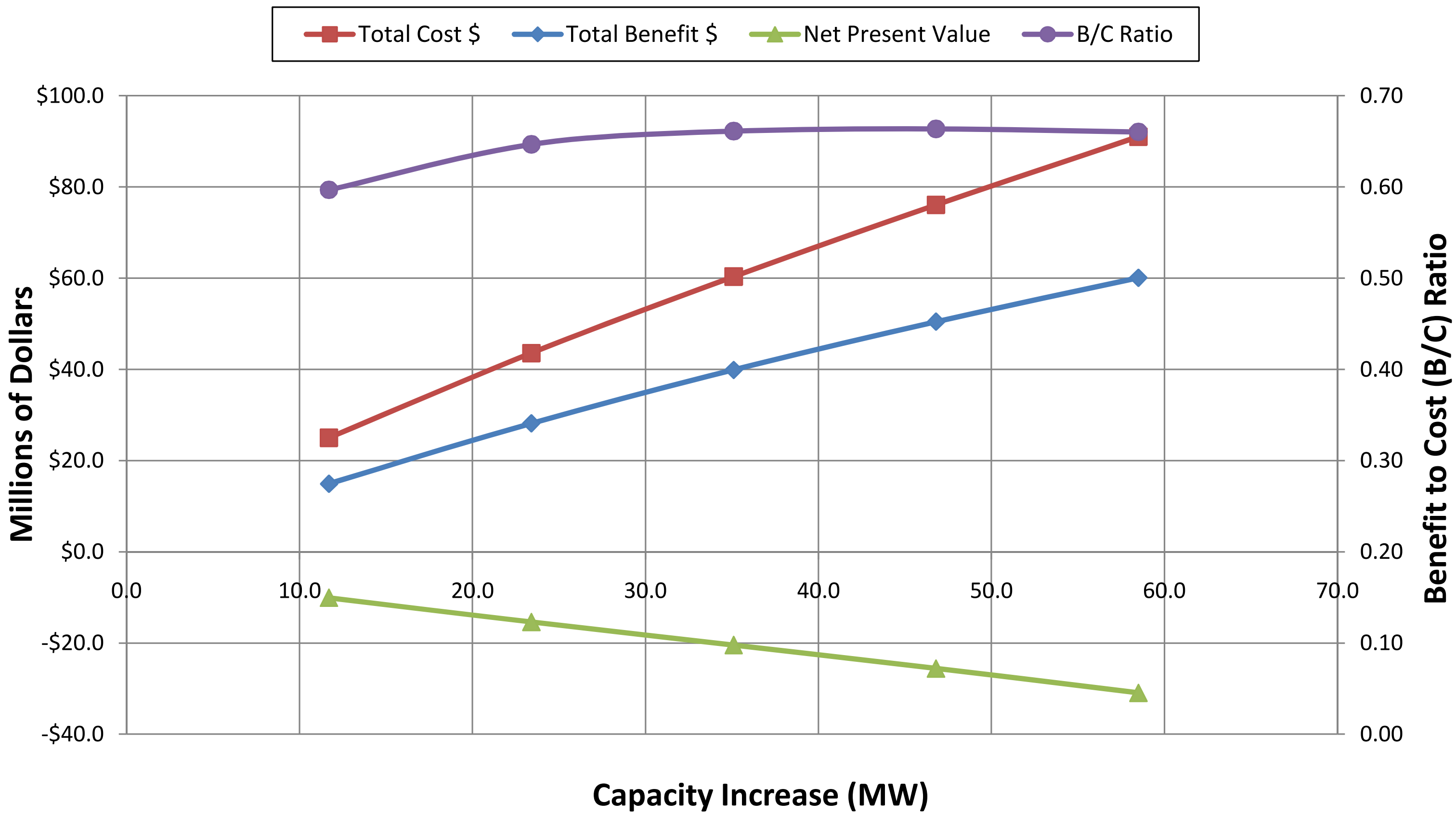
Summary of Capacity Increase Benefits and Costs
Judge Francis Carr

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	15.4	4,476	3%	$22.1	$1,434	$31.2	$8.0	$6.1	$14.2	-$17.0	0.45
20%	30.9	5,028	2%	$39.1	$1,268	$54.4	$9.0	$9.6	$18.6	-$35.8	0.34
30%	46.3	5,054	1%	$54.7	$1,181	$75.4	$9.0	$12.7	$21.7	-$53.6	0.29
40%	61.8	5,054	1%	$69.4	$1,123	$95.1	$9.0	$15.8	$24.8	-$70.2	0.26
50%	77.2	5,054	1%	$83.4	$1,081	$113.8	$9.0	$18.9	$27.9	-$85.9	0.25



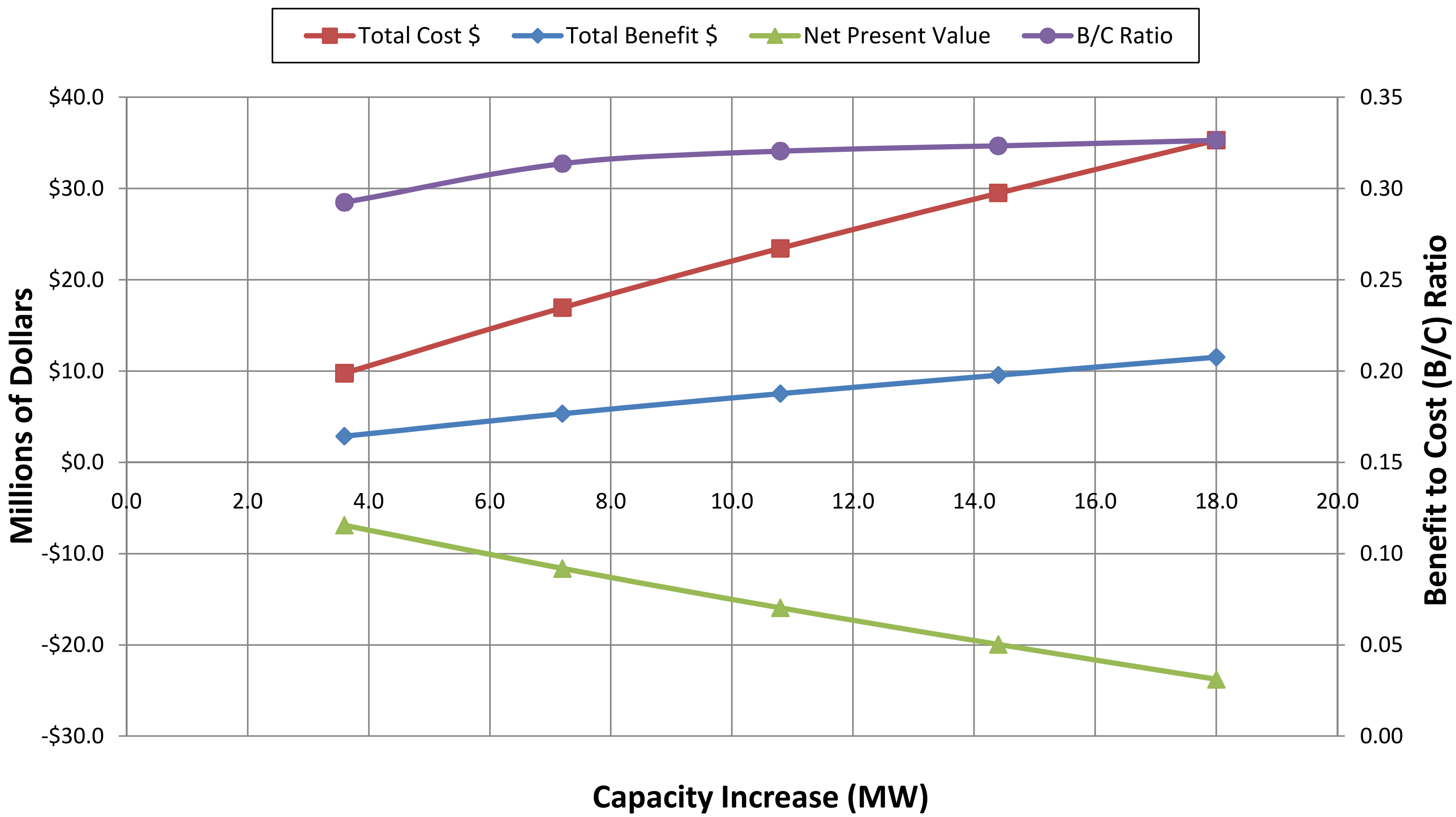
Summary of Capacity Increase Benefits and Costs
Keswick

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	11.7	5,517	5%	$17.6	$1,507	$25.0	$8.8	$6.1	$14.9	-$10.1	0.60
20%	23.4	10,308	5%	$31.2	$1,331	$43.5	$16.4	$11.7	$28.2	-$15.4	0.65
30%	35.1	14,427	5%	$43.5	$1,239	$60.3	$23.0	$16.9	$39.9	-$20.4	0.66
40%	46.8	18,040	4%	$55.2	$1,179	$76.0	$28.8	$21.7	$50.4	-$25.6	0.66
50%	58.5	21,245	4%	$66.3	$1,134	$91.0	$33.9	$26.2	$60.1	-$30.9	0.66



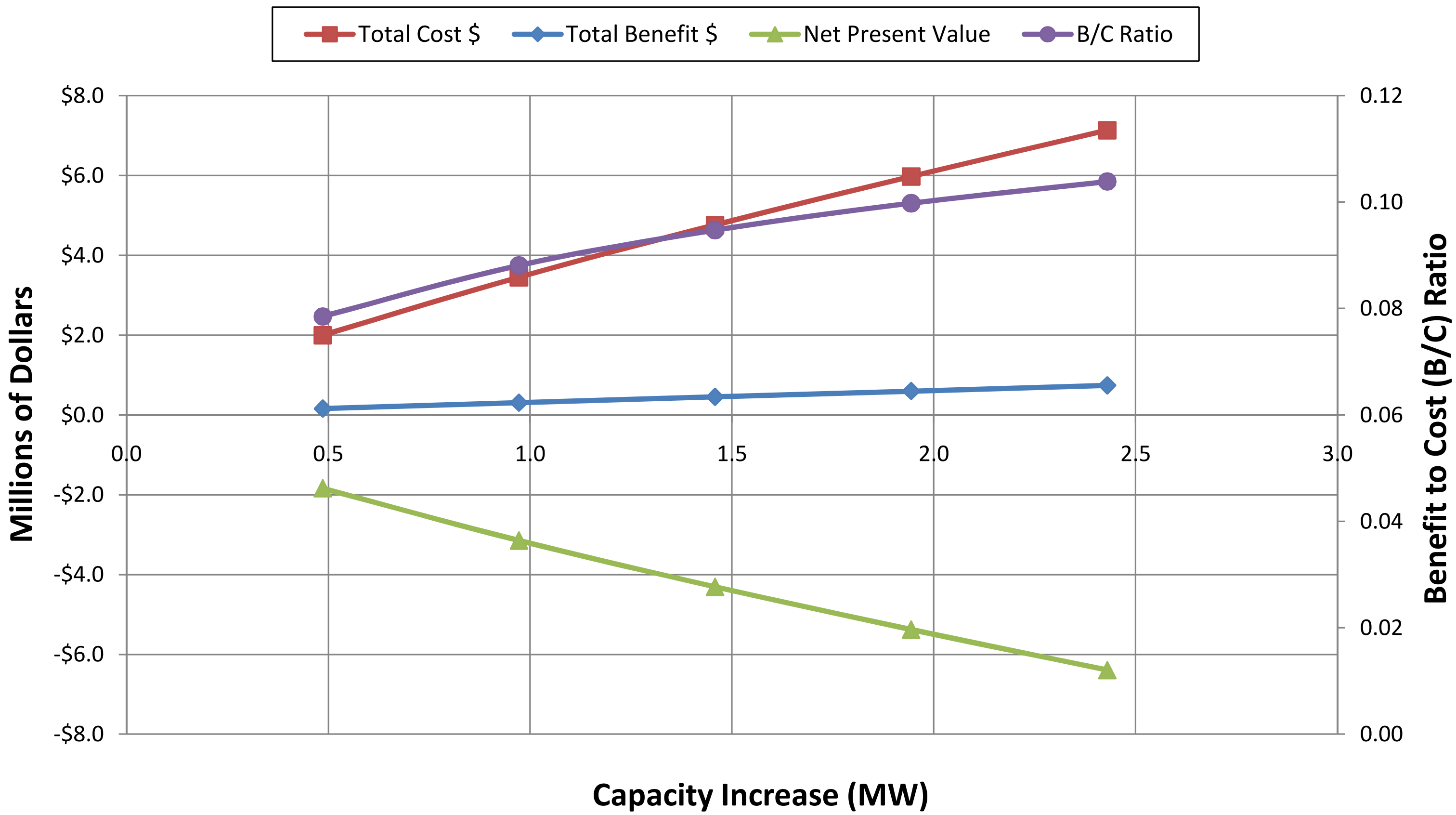
Summary of Capacity Increase Benefits and Costs
Kortes

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	3.6	1,236	4%	$6.7	$1,871	$9.7	$1.3	$1.6	$2.8	-$6.9	0.29
20%	7.2	2,248	4%	$11.9	$1,646	$16.9	$2.3	$3.0	$5.3	-$11.6	0.31
30%	10.8	3,104	3%	$16.5	$1,529	$23.4	$3.2	$4.3	$7.5	-$15.9	0.32
40%	14.4	3,864	3%	$20.9	$1,452	$29.5	$4.0	$5.5	$9.5	-$20.0	0.32
50%	18.0	4,594	3%	$25.1	$1,395	$35.3	$4.8	$6.7	$11.5	-$23.8	0.33



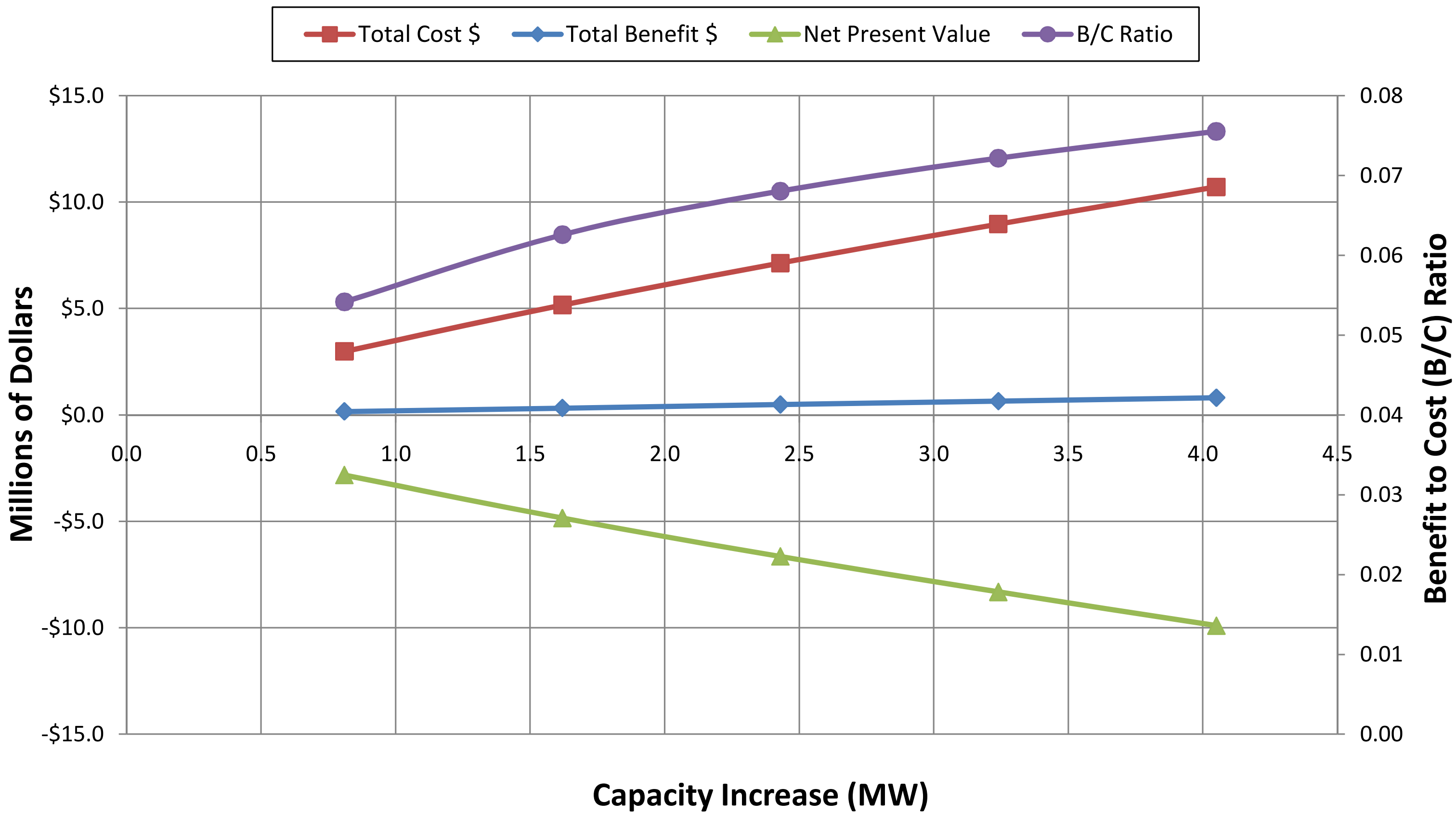
Summary of Capacity Increase Benefits and Costs
Lower Molina

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	0.5	31	1%	$1.3	$2,754	$2.0	$0.0	$0.1	$0.2	-$1.8	0.08
20%	1.0	57	1%	$2.3	$2,402	$3.4	$0.1	$0.2	$0.3	-$3.1	0.09
30%	1.5	83	1%	$3.2	$2,220	$4.8	$0.1	$0.3	$0.5	-$4.3	0.09
40%	1.9	108	1%	$4.1	$2,102	$6.0	$0.1	$0.5	$0.6	-$5.4	0.10
50%	2.4	133	1%	$4.9	$2,014	$7.1	$0.2	$0.6	$0.7	-$6.4	0.10



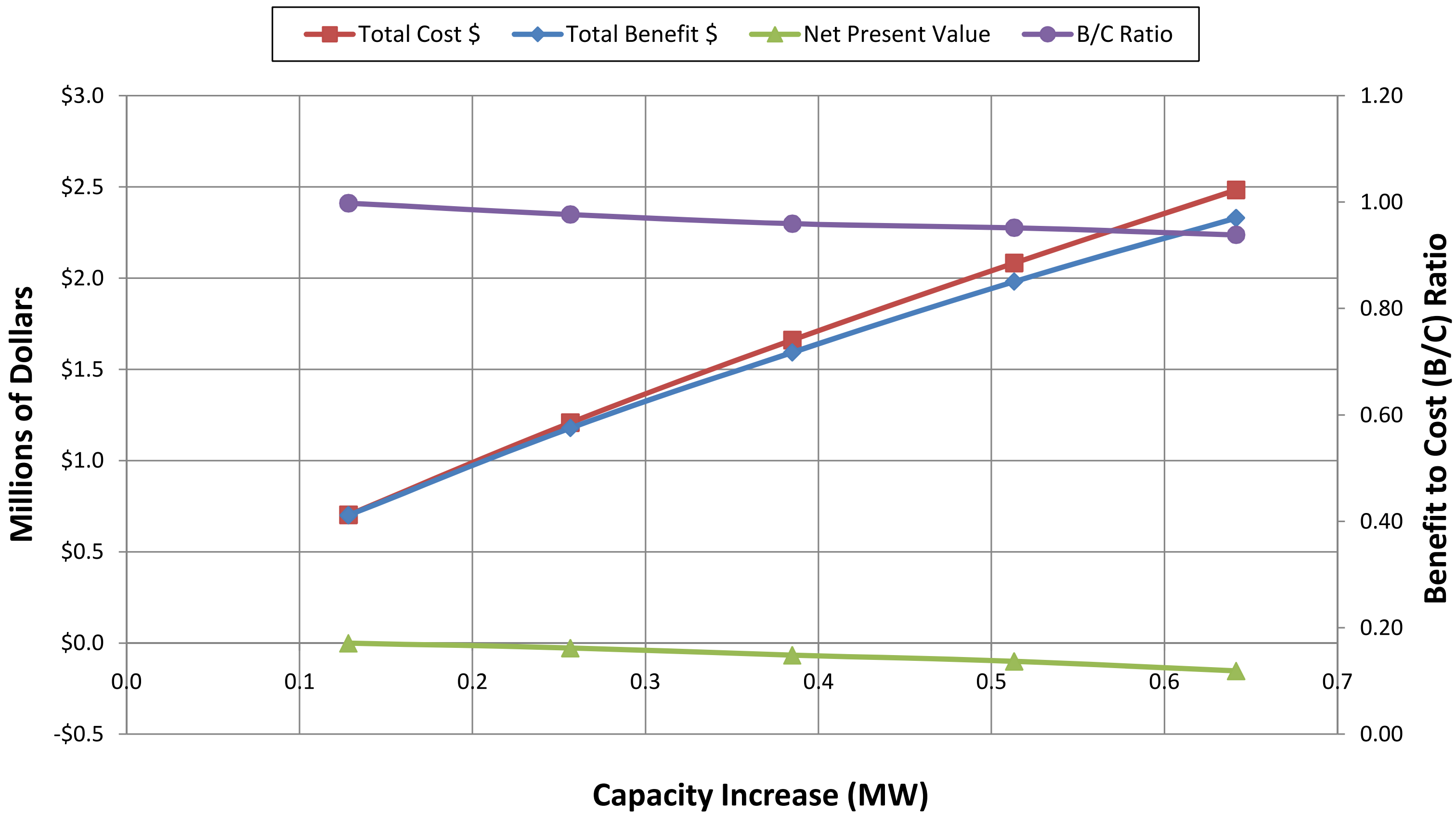
Summary of Capacity Increase Benefits and Costs
Marys Lake

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	0.8	0	0%	$2.0	$2,489	$3.0	$0.0	$0.2	$0.2	-$2.8	0.05
20%	1.6	0	0%	$3.5	$2,176	$5.2	$0.0	$0.3	$0.3	-$4.8	0.06
30%	2.4	0	0%	$4.9	$2,014	$7.1	$0.0	$0.5	$0.5	-$6.6	0.07
40%	3.2	0	0%	$6.2	$1,908	$9.0	$0.0	$0.6	$0.6	-$8.3	0.07
50%	4.1	0	0%	$7.4	$1,831	$10.7	$0.0	$0.8	$0.8	-$9.9	0.08



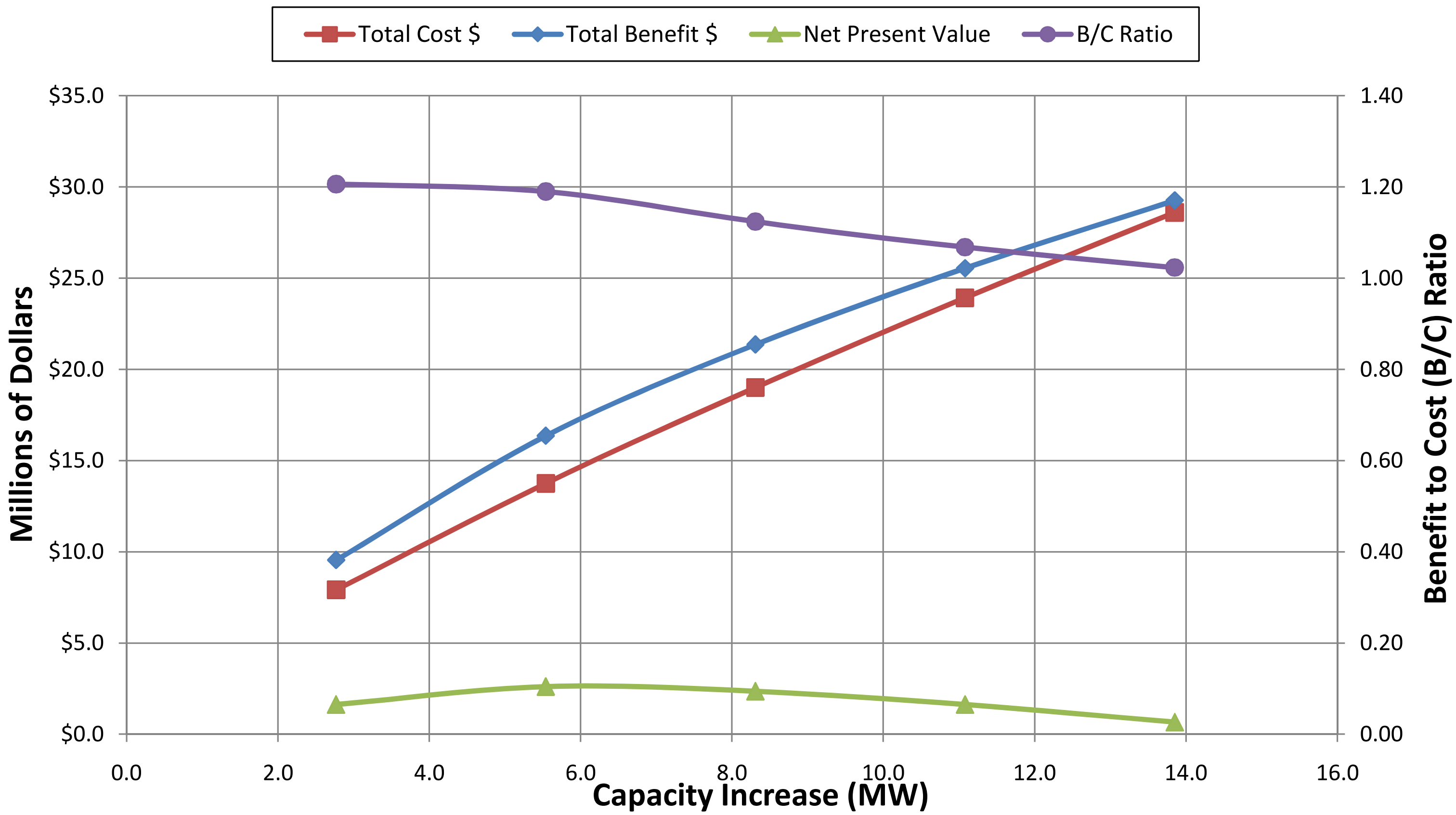
Summary of Capacity Increase Benefits and Costs
McPhee

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	0.1	322	29%	$0.5	$3,627	$0.7	$0.5	$0.2	$0.7	$0.0	1.00
20%	0.3	539	24%	$0.8	$3,136	$1.2	$0.8	$0.4	$1.2	$0.0	0.98
30%	0.4	724	21%	$1.1	$2,887	$1.7	$1.0	$0.6	$1.6	-$0.1	0.96
40%	0.5	897	20%	$1.4	$2,724	$2.1	$1.3	$0.7	$2.0	-$0.1	0.95
50%	0.6	1,051	19%	$1.7	$2,606	$2.5	$1.5	$0.8	$2.3	-$0.2	0.94



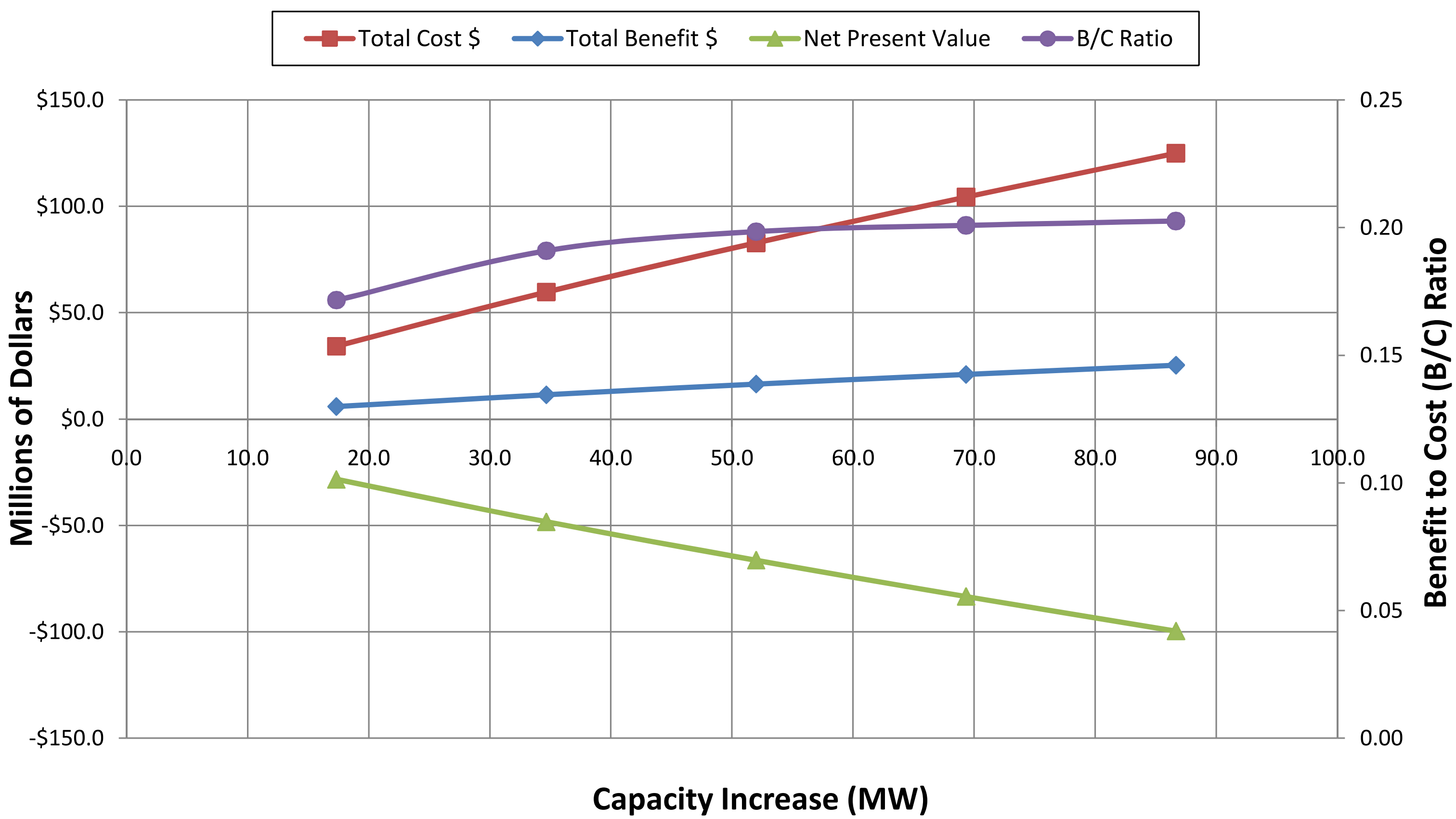
Summary of Capacity Increase Benefits and Costs
Minidoka

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	2.8	5,025	21%	$5.4	$1,965	$7.9	$5.6	$4.0	$9.5	$1.6	1.21
20%	5.5	8,523	18%	$9.6	$1,727	$13.7	$9.4	$6.9	$16.4	$2.6	1.19
30%	8.3	11,009	15%	$13.3	$1,604	$19.0	$12.2	$9.2	$21.4	$2.4	1.12
40%	11.1	13,040	13%	$16.9	$1,522	$23.9	$14.4	$11.1	$25.5	$1.6	1.07
50%	13.9	14,807	12%	$20.2	$1,462	$28.6	$16.4	$12.9	$29.3	$0.7	1.02



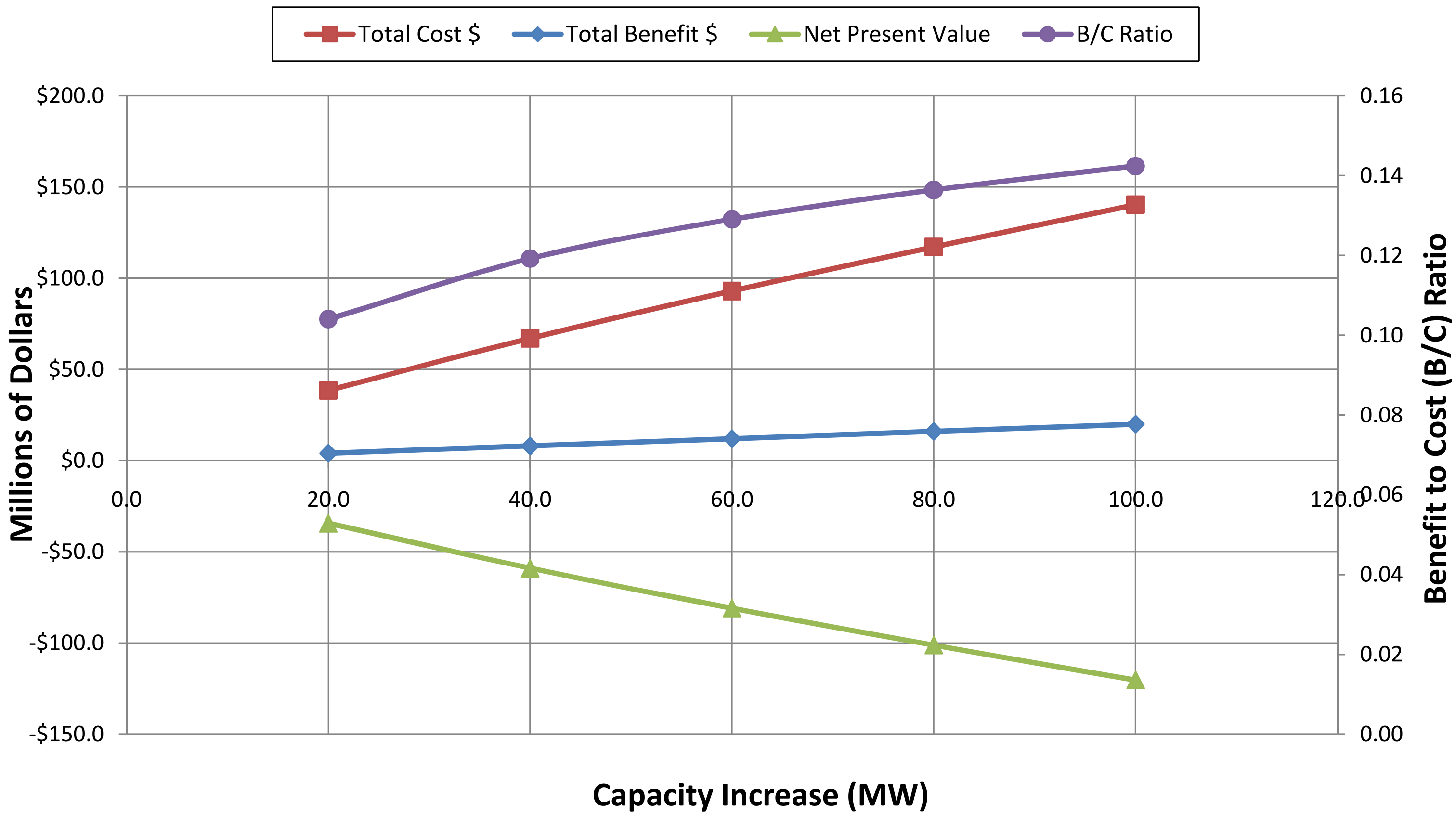
Summary of Capacity Increase Benefits and Costs
Morrow Point

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	17.3	1,152	1%	$24.3	$1,404	$34.2	$1.6	$4.2	$5.9	-$28.4	0.17
20%	34.7	2,139	1%	$43.1	$1,242	$59.7	$3.0	$8.4	$11.4	-$48.3	0.19
30%	52.0	2,884	1%	$60.2	$1,157	$82.8	$4.1	$12.4	$16.4	-$66.3	0.20
40%	69.3	3,401	1%	$76.3	$1,101	$104.3	$4.8	$16.2	$21.0	-$83.4	0.20
50%	86.7	3,823	1%	$91.8	$1,059	$124.9	$5.4	$19.9	$25.3	-$99.6	0.20



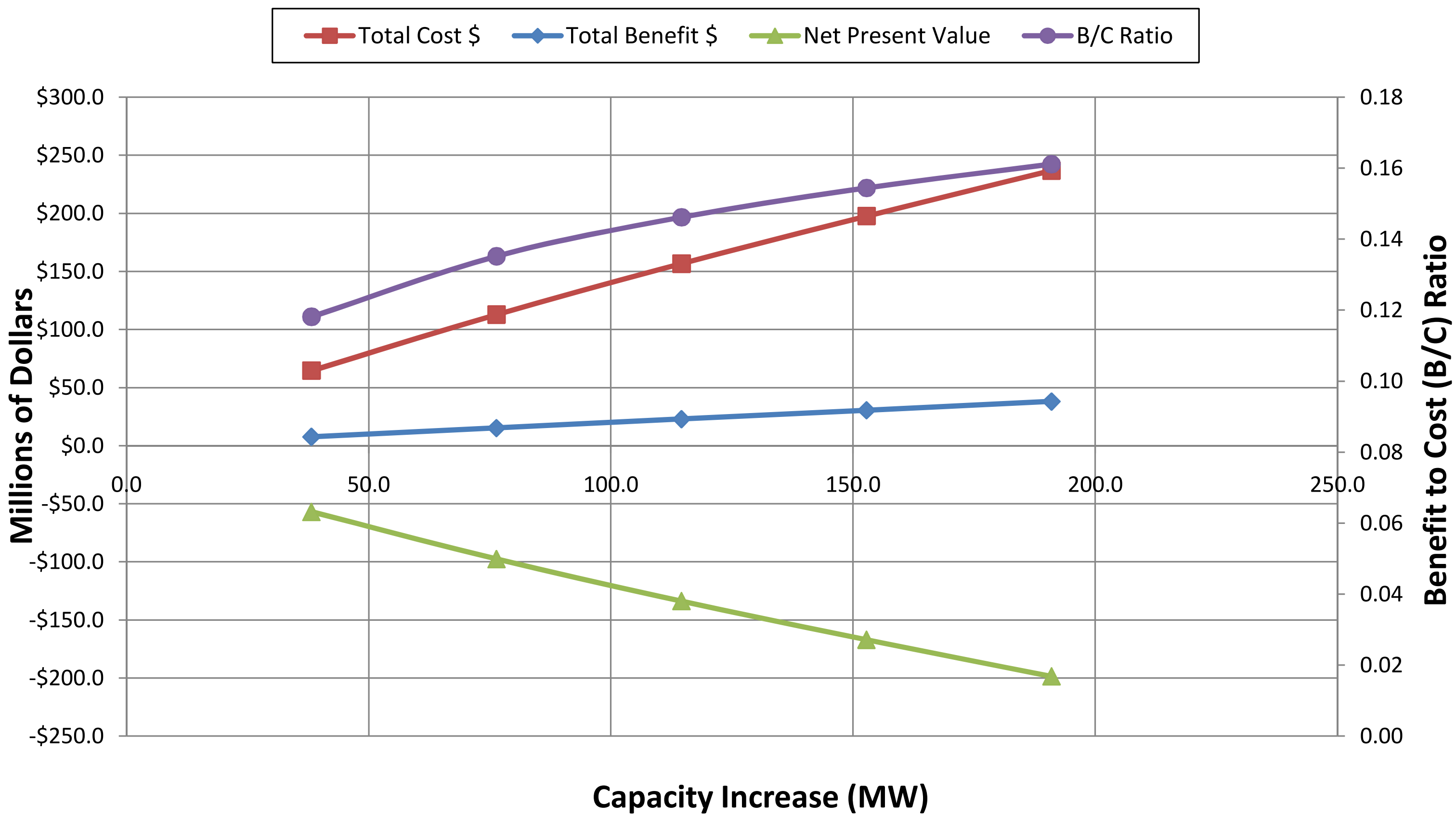
Summary of Capacity Increase Benefits and Costs
Mount Elbert

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	20.0	0	0%	$27.4	$1,369	$38.4	$0.0	$4.0	$4.0	-$34.4	0.10
20%	40.0	0	0%	$48.5	$1,211	$67.0	$0.0	$8.0	$8.0	-$59.0	0.12
30%	60.0	0	0%	$67.7	$1,129	$92.9	$0.0	$12.0	$12.0	-$80.9	0.13
40%	80.0	0	0%	$85.9	$1,074	$117.1	$0.0	$16.0	$16.0	-$101.1	0.14
50%	100.0	0	0%	$103.4	$1,034	$140.2	$0.0	$20.0	$20.0	-$120.3	0.14



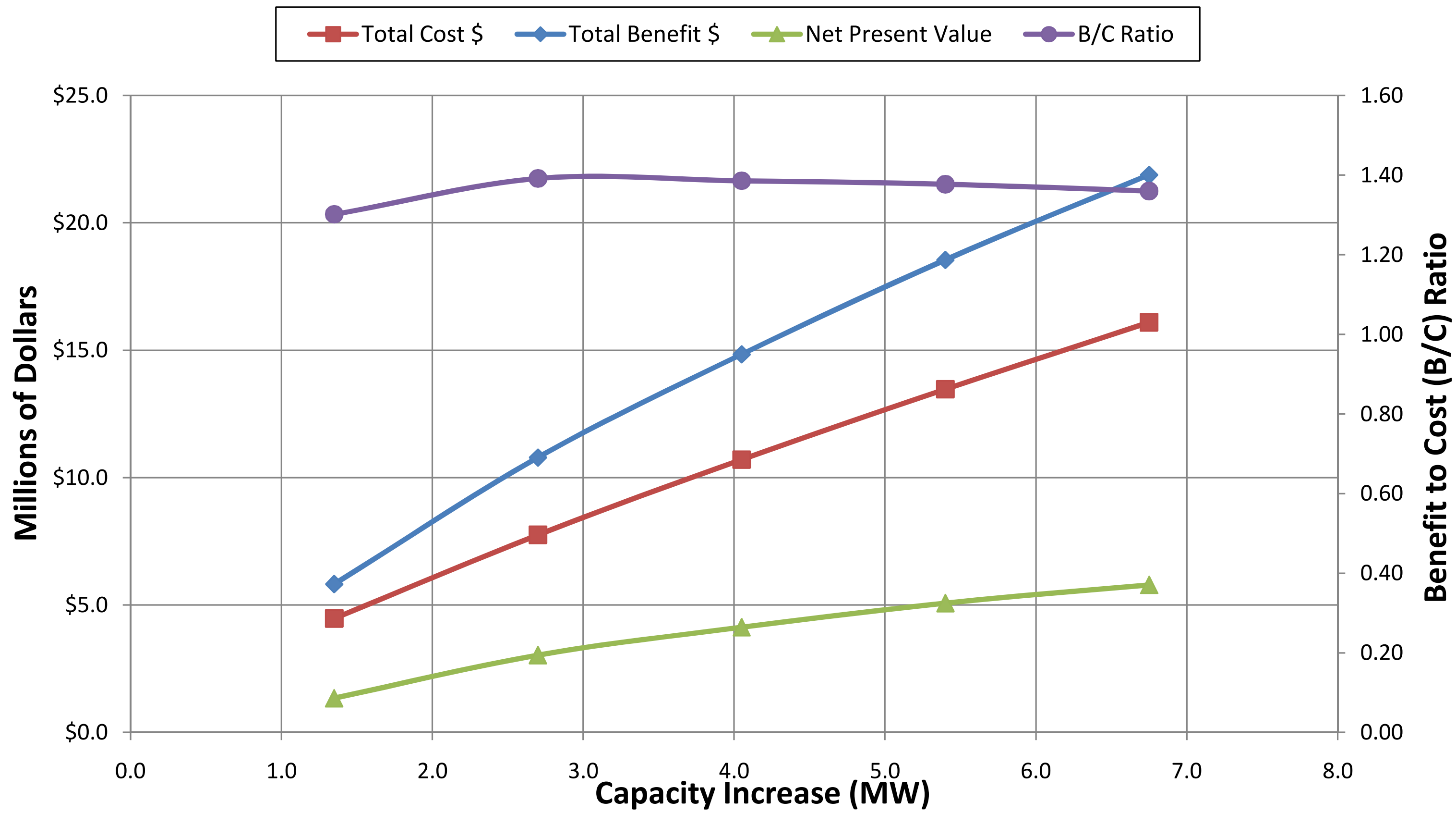
Summary of Capacity Increase Benefits and Costs
New Melones

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	38.2	0	0%	$46.6	$1,221	$64.6	$0.0	$7.6	$7.6	-$56.9	0.12
20%	76.4	0	0%	$82.7	$1,083	$112.8	$0.0	$15.3	$15.3	-$97.6	0.14
30%	114.6	0	0%	$115.8	$1,010	$156.6	$0.0	$22.9	$22.9	-$133.7	0.15
40%	152.8	0	0%	$147.0	$962	$197.6	$0.0	$30.5	$30.5	-$167.1	0.15
50%	191.0	0	0%	$176.9	$926	$236.7	$0.0	$38.1	$38.1	-$198.5	0.16



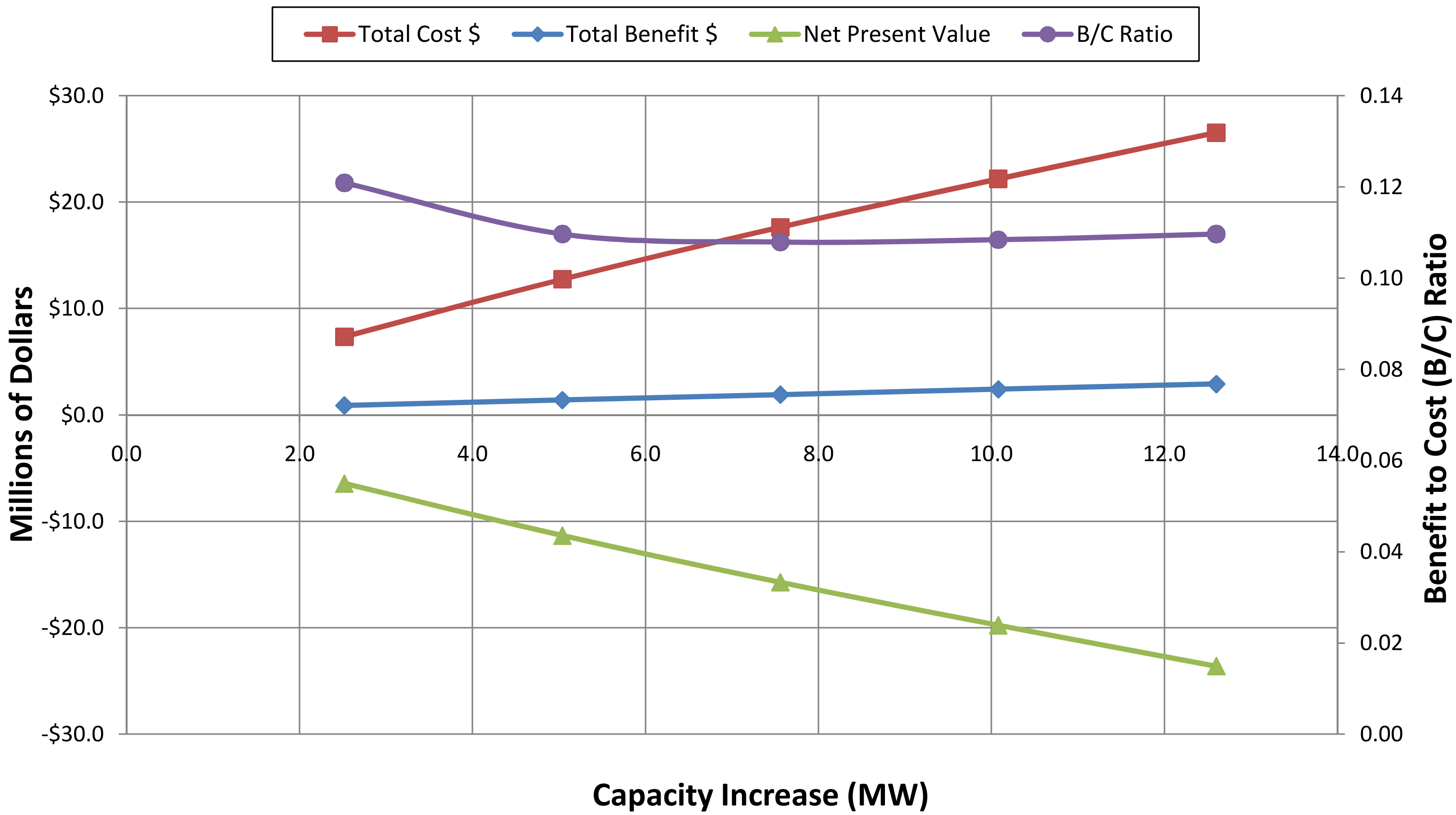
Summary of Capacity Increase Benefits and Costs
Nimbus

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	1.4	2,664	23%	$3.0	$2,254	$4.5	$3.7	$2.1	$5.8	$1.3	1.30
20%	2.7	4,920	21%	$5.3	$1,975	$7.8	$6.9	$3.9	$10.8	$3.0	1.39
30%	4.1	6,734	19%	$7.4	$1,831	$10.7	$9.4	$5.4	$14.8	$4.1	1.39
40%	5.4	8,384	18%	$9.4	$1,736	$13.5	$11.7	$6.8	$18.5	$5.1	1.38
50%	6.8	9,857	17%	$11.2	$1,666	$16.1	$13.8	$8.1	$21.9	$5.8	1.36



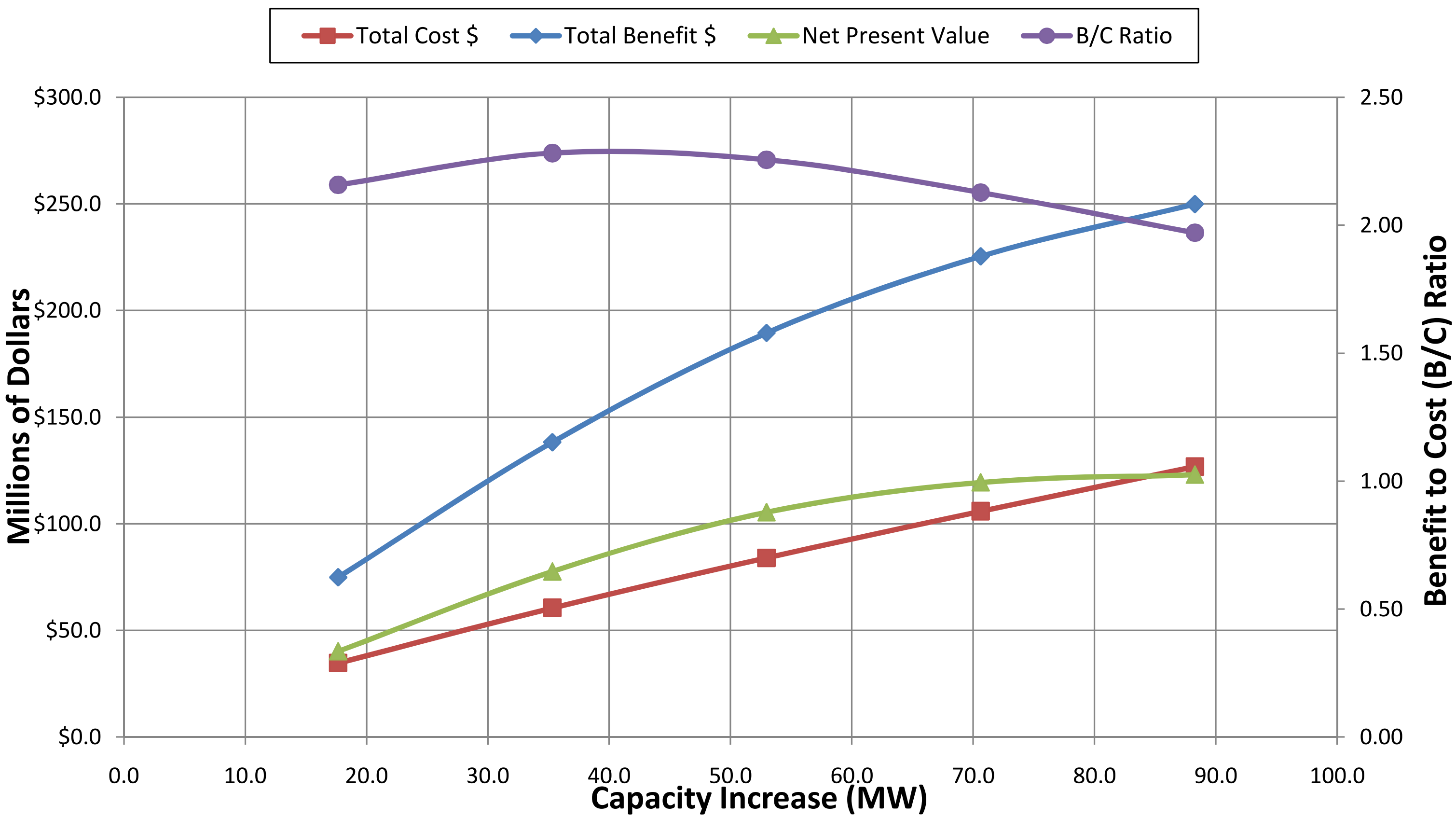
Summary of Capacity Increase Benefits and Costs
ONeill

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	2.5	155	1%	$5.0	$2,001	$7.3	$0.3	$0.6	$0.9	-$6.5	0.12
20%	5.0	158	0%	$8.9	$1,758	$12.7	$0.3	$1.1	$1.4	-$11.3	0.11
30%	7.6	158	0%	$12.3	$1,632	$17.6	$0.3	$1.6	$1.9	-$15.7	0.11
40%	10.1	158	0%	$15.6	$1,548	$22.2	$0.3	$2.1	$2.4	-$19.8	0.11
50%	12.6	158	0%	$18.7	$1,487	$26.5	$0.3	$2.6	$2.9	-$23.6	0.11



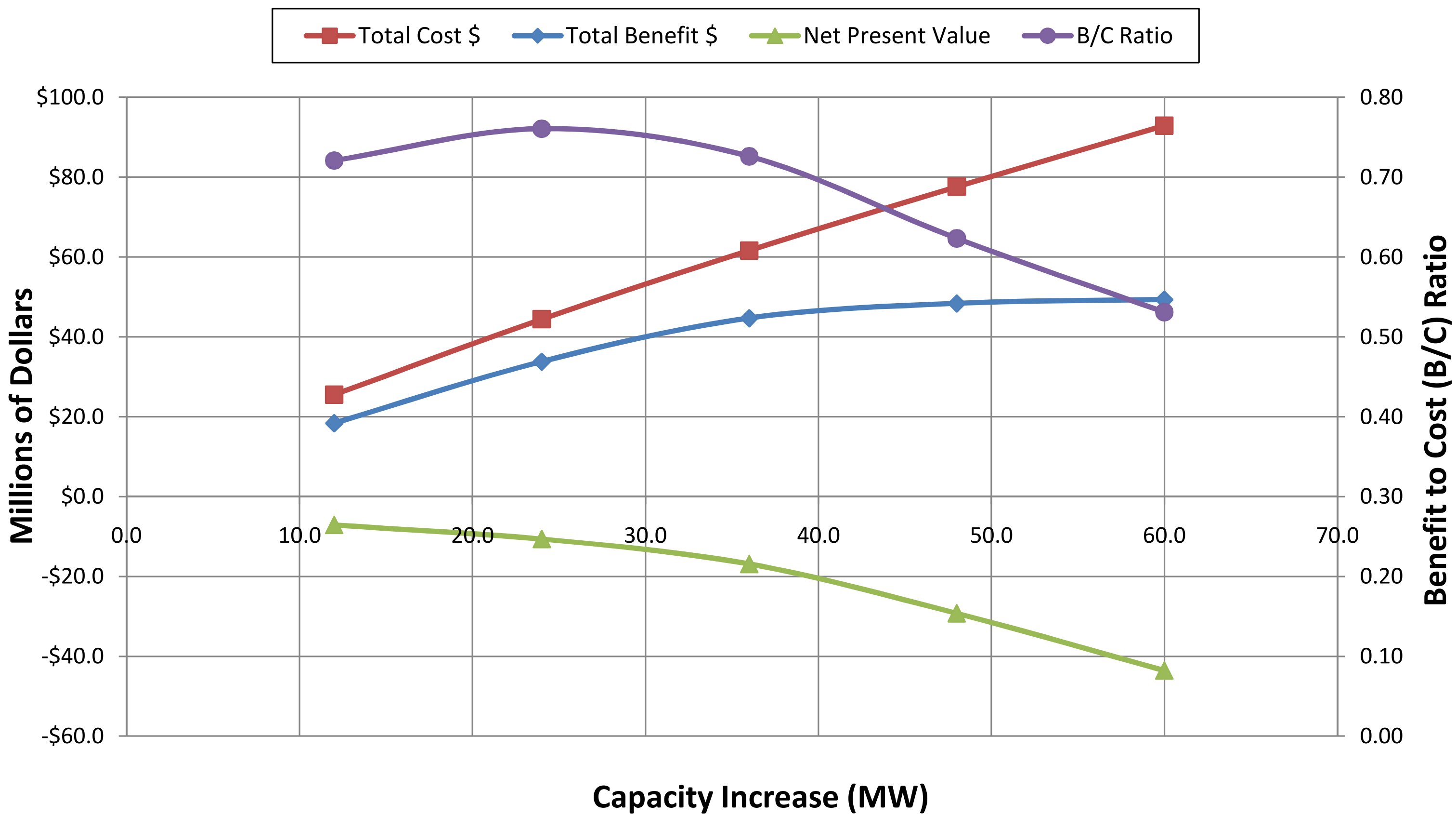
Summary of Capacity Increase Benefits and Costs
Palisades

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	17.7	39,931	26%	$24.7	$1,400	$34.7	$44.1	$30.8	$75.0	$40.2	2.16
20%	35.3	73,362	24%	$43.7	$1,238	$60.6	$81.1	$57.2	$138.3	$77.7	2.28
30%	53.0	99,993	22%	$61.1	$1,153	$84.0	$110.5	$78.9	$189.5	$105.5	2.26
40%	70.6	118,090	19%	$77.5	$1,097	$105.9	$130.5	$94.8	$225.4	$119.4	2.13
50%	88.3	129,829	17%	$93.2	$1,056	$126.8	$143.5	$106.4	$249.9	$123.1	1.97



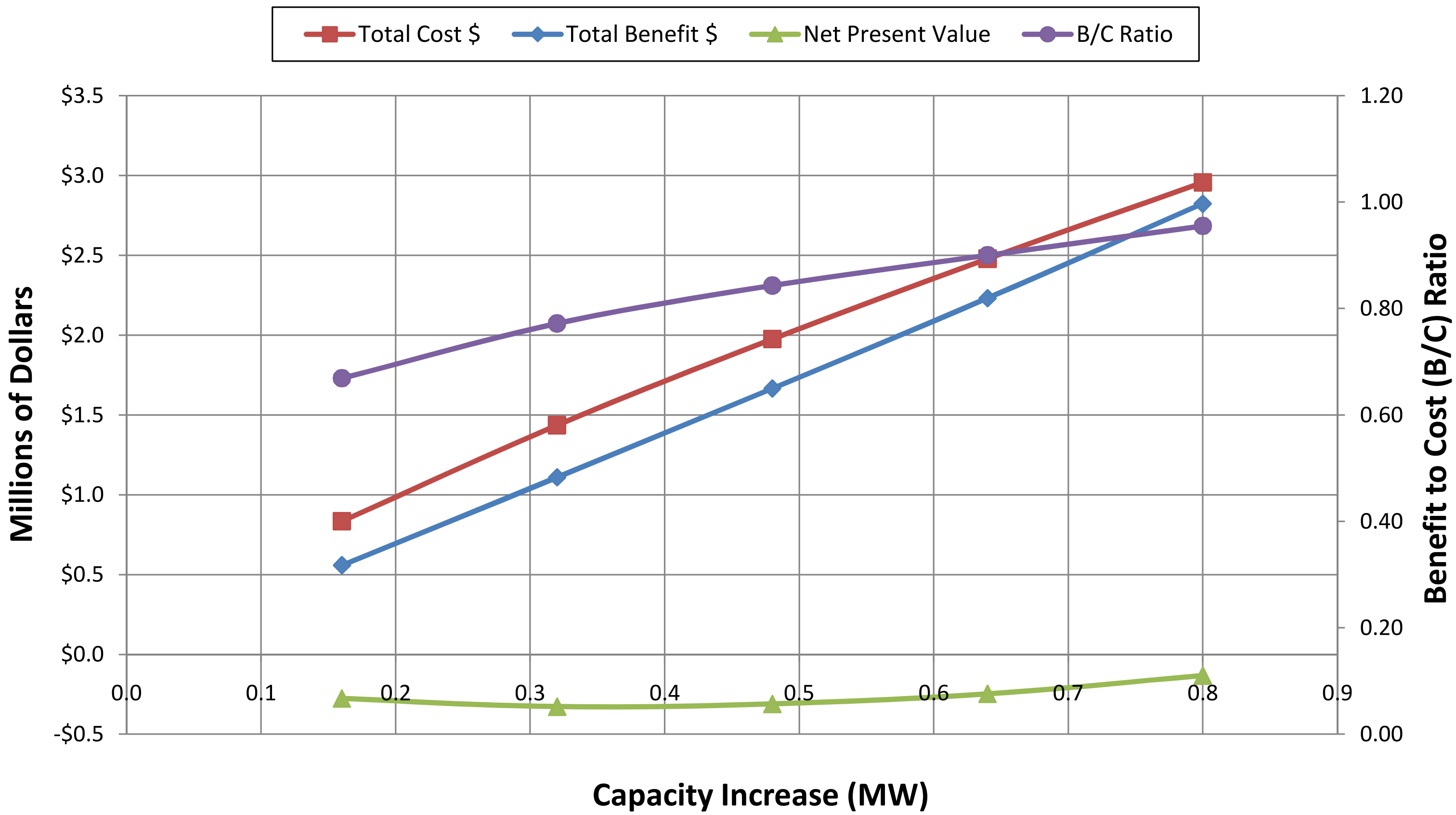
Summary of Capacity Increase Benefits and Costs
Parker

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	12.0	8,289	8%	$18.0	$1,500	$25.5	$10.3	$8.1	$18.4	-$7.1	0.72
20%	24.0	15,049	7%	$31.8	$1,325	$44.4	$18.7	$15.1	$33.8	-$10.6	0.76
30%	36.0	19,454	6%	$44.4	$1,234	$61.6	$24.2	$20.5	$44.7	-$16.9	0.73
40%	48.0	20,113	5%	$56.3	$1,173	$77.6	$25.0	$23.3	$48.3	-$29.2	0.62
50%	60.0	19,365	4%	$67.7	$1,129	$92.9	$24.1	$25.2	$49.3	-$43.6	0.53



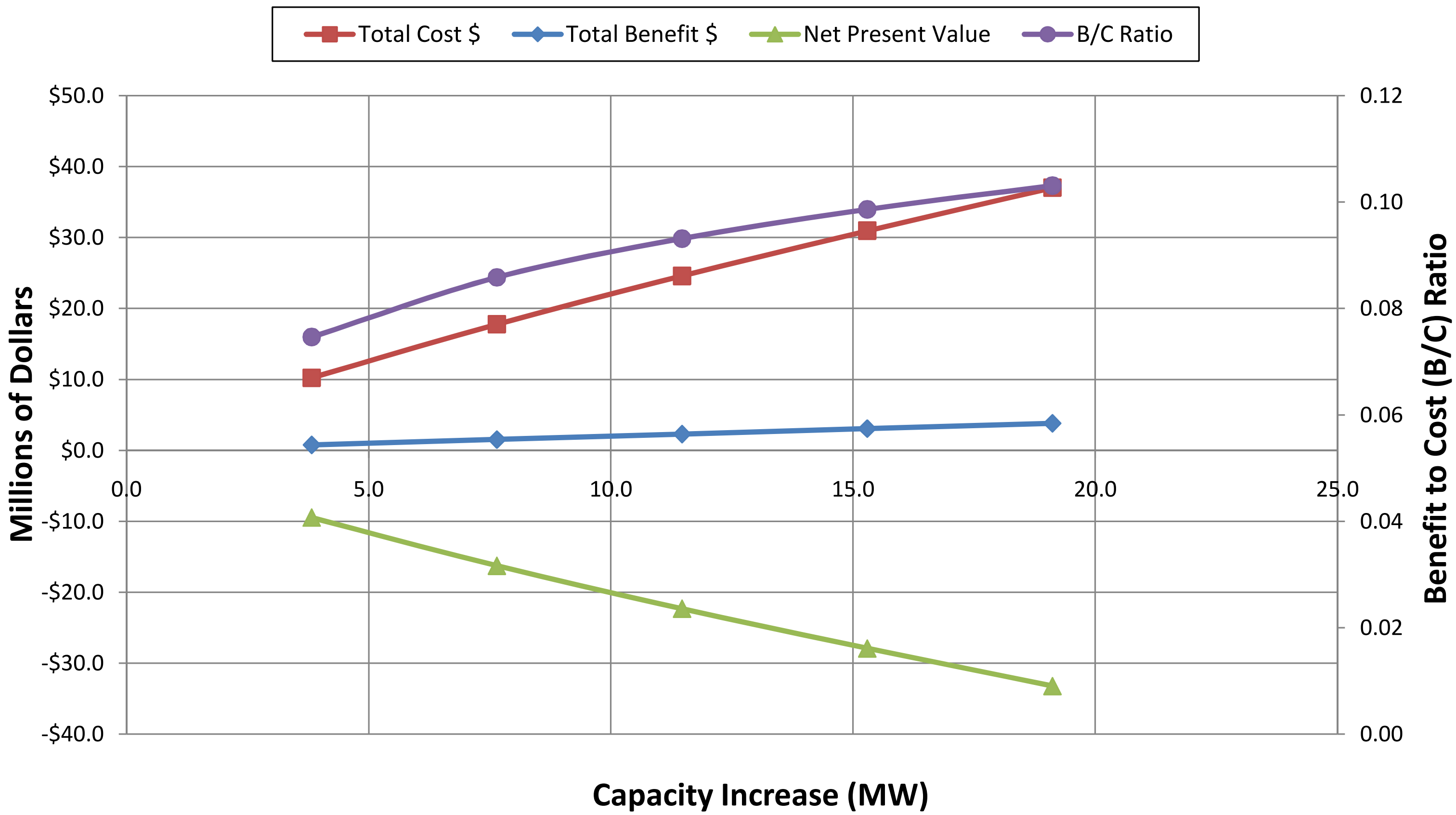
Summary of Capacity Increase Benefits and Costs
Pilot Butte

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	0.2	342	24%	$0.6	$3,460	$0.8	$0.3	$0.3	$0.6	-$0.3	0.67
20%	0.3	679	24%	$1.0	$2,997	$1.4	$0.6	$0.5	$1.1	-$0.3	0.77
30%	0.5	1,021	24%	$1.3	$2,761	$2.0	$0.9	$0.8	$1.7	-$0.3	0.84
40%	0.6	1,368	24%	$1.7	$2,607	$2.5	$1.2	$1.1	$2.2	-$0.2	0.90
50%	0.8	1,732	25%	$2.0	$2,495	$3.0	$1.5	$1.3	$2.8	-$0.1	0.96



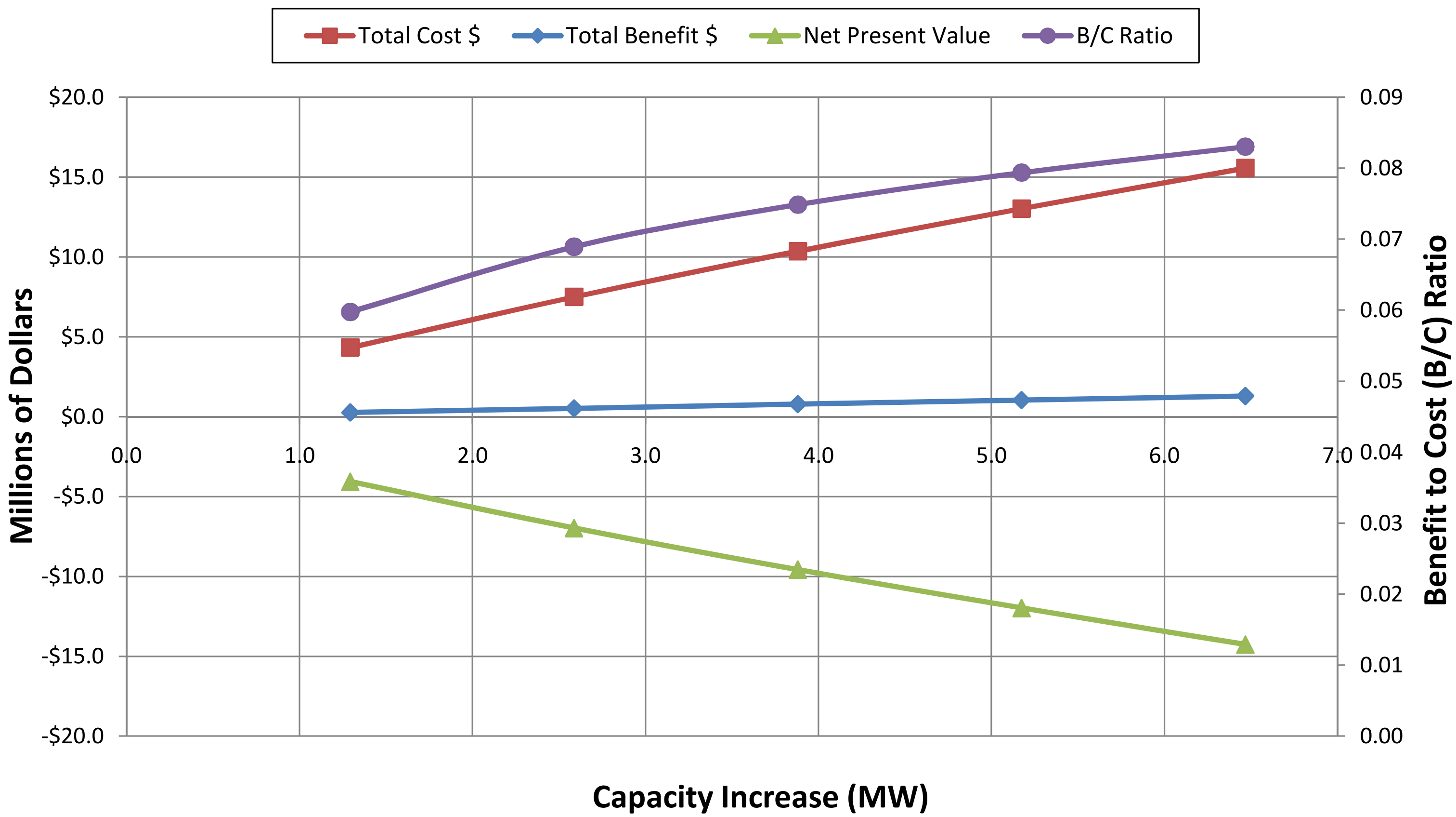
Summary of Capacity Increase Benefits and Costs
Pole Hill

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	3.8	0	0%	$7.1	$1,850	$10.2	$0.0	$0.8	$0.8	-$9.5	0.07
20%	7.6	0	0%	$12.5	$1,628	$17.8	$0.0	$1.5	$1.5	-$16.3	0.09
30%	11.5	0	0%	$17.4	$1,513	$24.6	$0.0	$2.3	$2.3	-$22.3	0.09
40%	15.3	0	0%	$22.0	$1,436	$31.0	$0.0	$3.1	$3.1	-$27.9	0.10
50%	19.1	0	0%	$26.4	$1,380	$37.0	$0.0	$3.8	$3.8	-$33.2	0.10



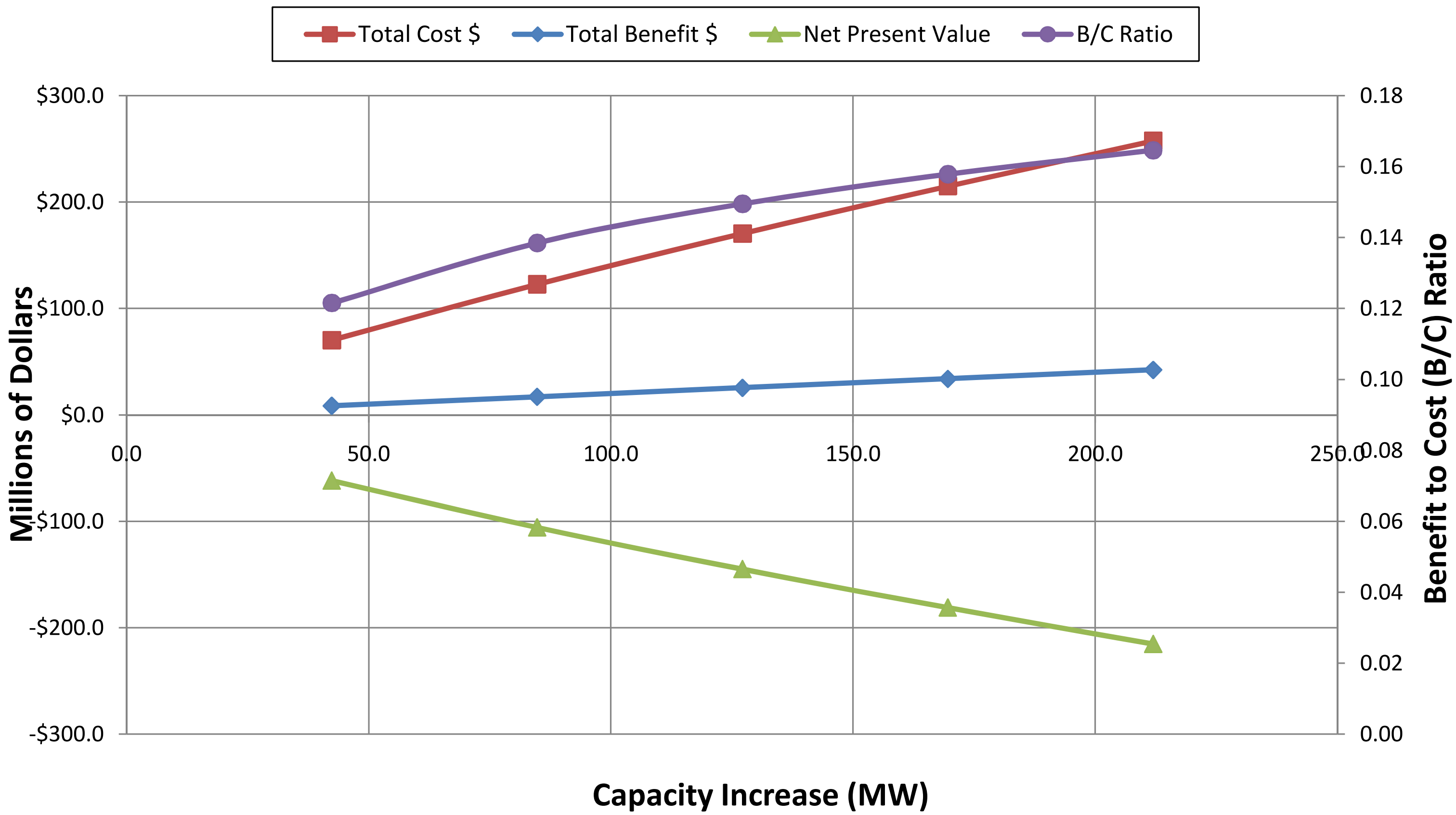
Summary of Capacity Increase Benefits and Costs
Roza

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	1.3	0	0%	$2.9	$2,272	$4.3	$0.0	$0.3	$0.3	-$4.1	0.06
20%	2.6	0	0%	$5.2	$1,991	$7.5	$0.0	$0.5	$0.5	-$7.0	0.07
30%	3.9	0	0%	$7.2	$1,845	$10.3	$0.0	$0.8	$0.8	-$9.6	0.07
40%	5.2	0	0%	$9.1	$1,749	$13.0	$0.0	$1.0	$1.0	-$12.0	0.08
50%	6.5	0	0%	$10.9	$1,679	$15.6	$0.0	$1.3	$1.3	-$14.3	0.08



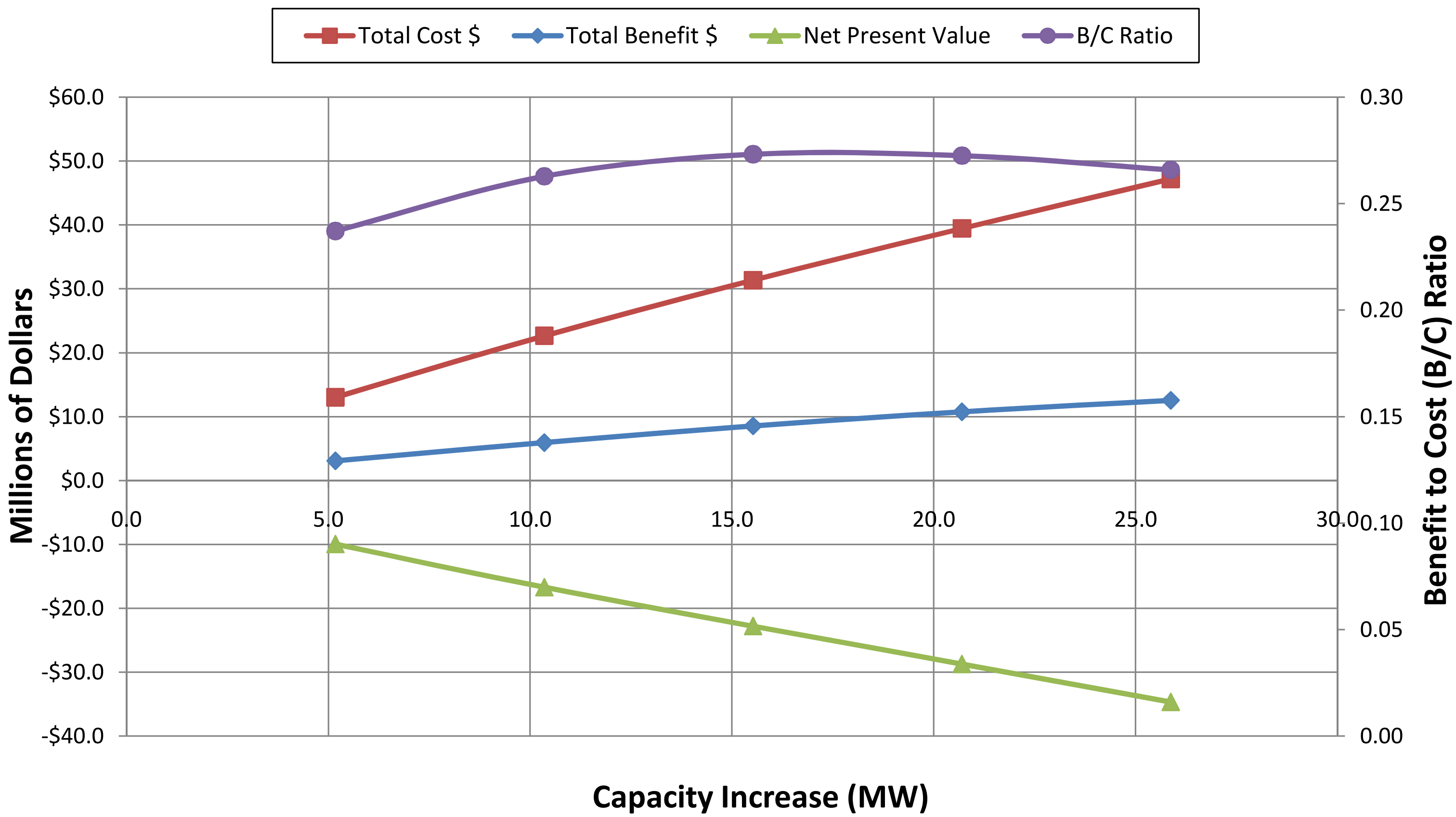
Summary of Capacity Increase Benefits and Costs
San Luis

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	42.4	33	0%	$50.8	$1,199	$70.2	$0.0	$8.5	$8.5	-$61.7	0.12
20%	84.8	33	0%	$90.2	$1,063	$122.8	$0.0	$17.0	$17.0	-$105.8	0.14
30%	127.2	33	0%	$126.2	$992	$170.3	$0.0	$25.4	$25.5	-$144.9	0.15
40%	169.6	33	0%	$160.3	$945	$215.0	$0.0	$33.9	$33.9	-$181.0	0.16
50%	212.0	33	0%	$193.0	$910	$257.5	$0.0	$42.3	$42.4	-$215.2	0.16



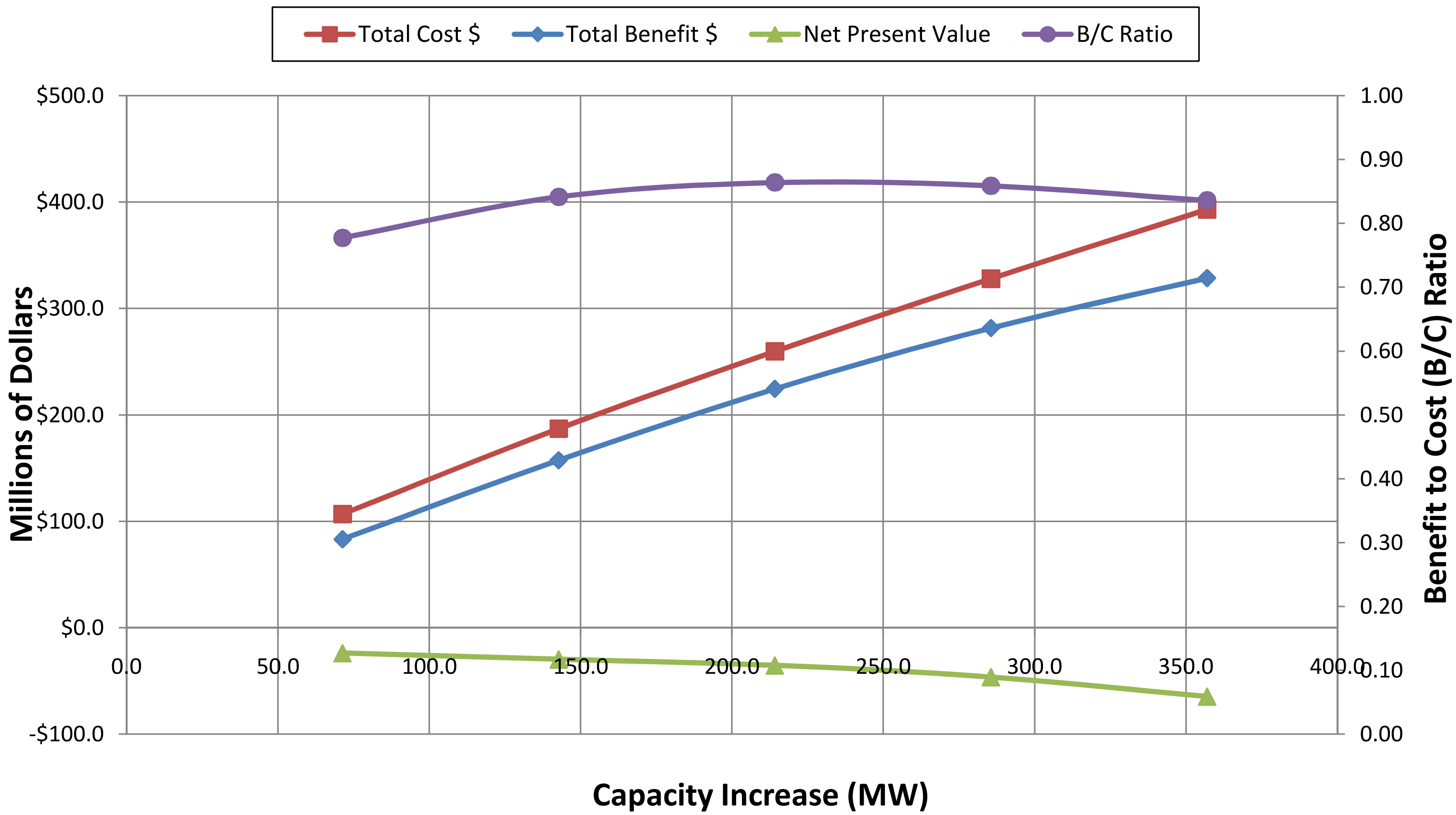
Summary of Capacity Increase Benefits and Costs
Seminoe

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	5.2	1,174	3%	$9.1	$1,749	$13.0	$1.3	$1.8	$3.1	-$9.9	0.24
20%	10.4	2,222	2%	$15.9	$1,541	$22.6	$2.4	$3.6	$6.0	-$16.7	0.26
30%	15.5	3,123	2%	$22.2	$1,432	$31.3	$3.3	$5.2	$8.6	-$22.8	0.27
40%	20.7	3,788	2%	$28.2	$1,361	$39.5	$4.0	$6.7	$10.8	-$28.7	0.27
50%	25.9	4,224	2%	$33.8	$1,308	$47.2	$4.5	$8.1	$12.6	-$34.7	0.27



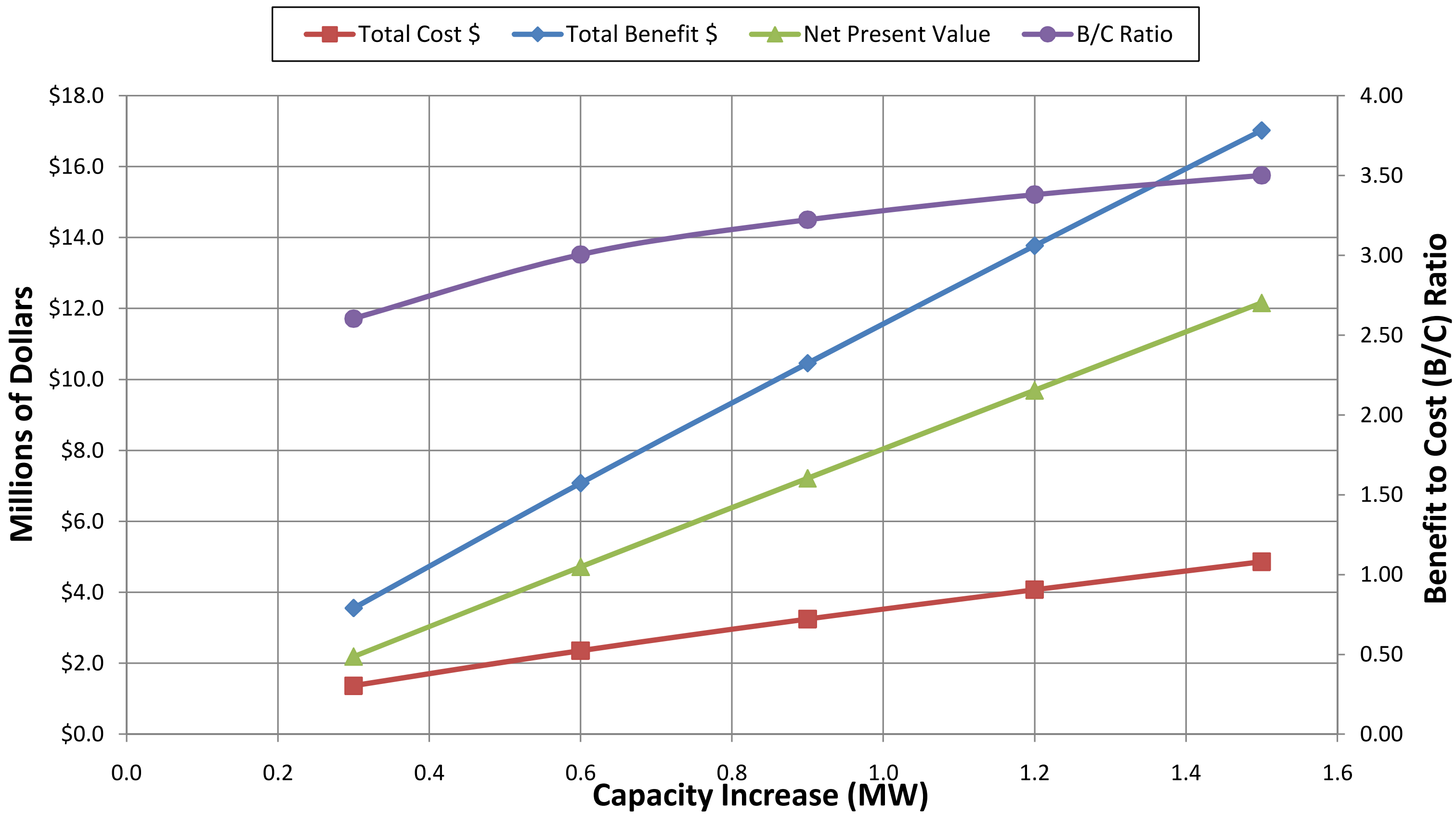
Summary of Capacity Increase Benefits and Costs
Shasta

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	71.4	27,813	4%	$78.2	$1,095	$106.8	$49.8	$33.3	$83.1	-$23.8	0.78
20%	142.8	52,099	4%	$138.9	$973	$187.0	$93.3	$64.1	$157.4	-$29.7	0.84
30%	214.2	73,426	4%	$194.6	$909	$259.7	$131.4	$93.0	$224.4	-$35.3	0.86
40%	285.6	90,794	4%	$247.4	$866	$327.9	$162.5	$119.1	$281.6	-$46.3	0.86
50%	357.0	103,991	3%	$298.0	$835	$393.0	$186.1	$142.4	$328.5	-$64.5	0.84



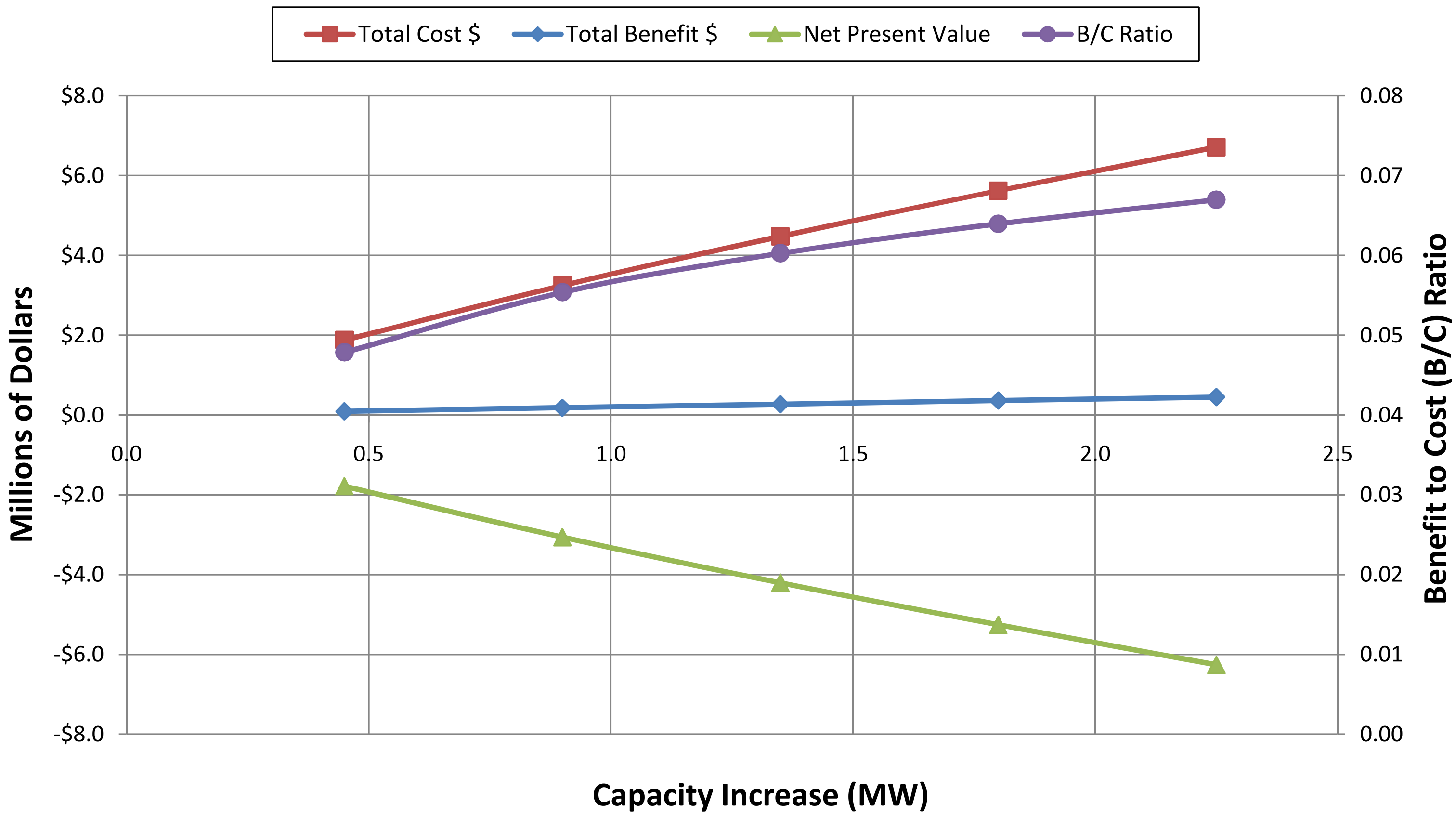
Summary of Capacity Increase Benefits and Costs
Shoshone

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	0.3	2,502	95%	$0.9	$3,037	$1.4	$2.6	$1.0	$3.6	$2.2	2.60
20%	0.6	4,980	95%	$1.6	$2,641	$2.4	$5.1	$1.9	$7.1	$4.7	3.00
30%	0.9	7,343	93%	$2.2	$2,438	$3.2	$7.6	$2.9	$10.5	$7.2	3.22
40%	1.2	9,653	92%	$2.8	$2,305	$4.1	$10.0	$3.8	$13.8	$9.7	3.38
50%	1.5	11,913	91%	$3.3	$2,208	$4.9	$12.3	$4.7	$17.0	$12.2	3.50



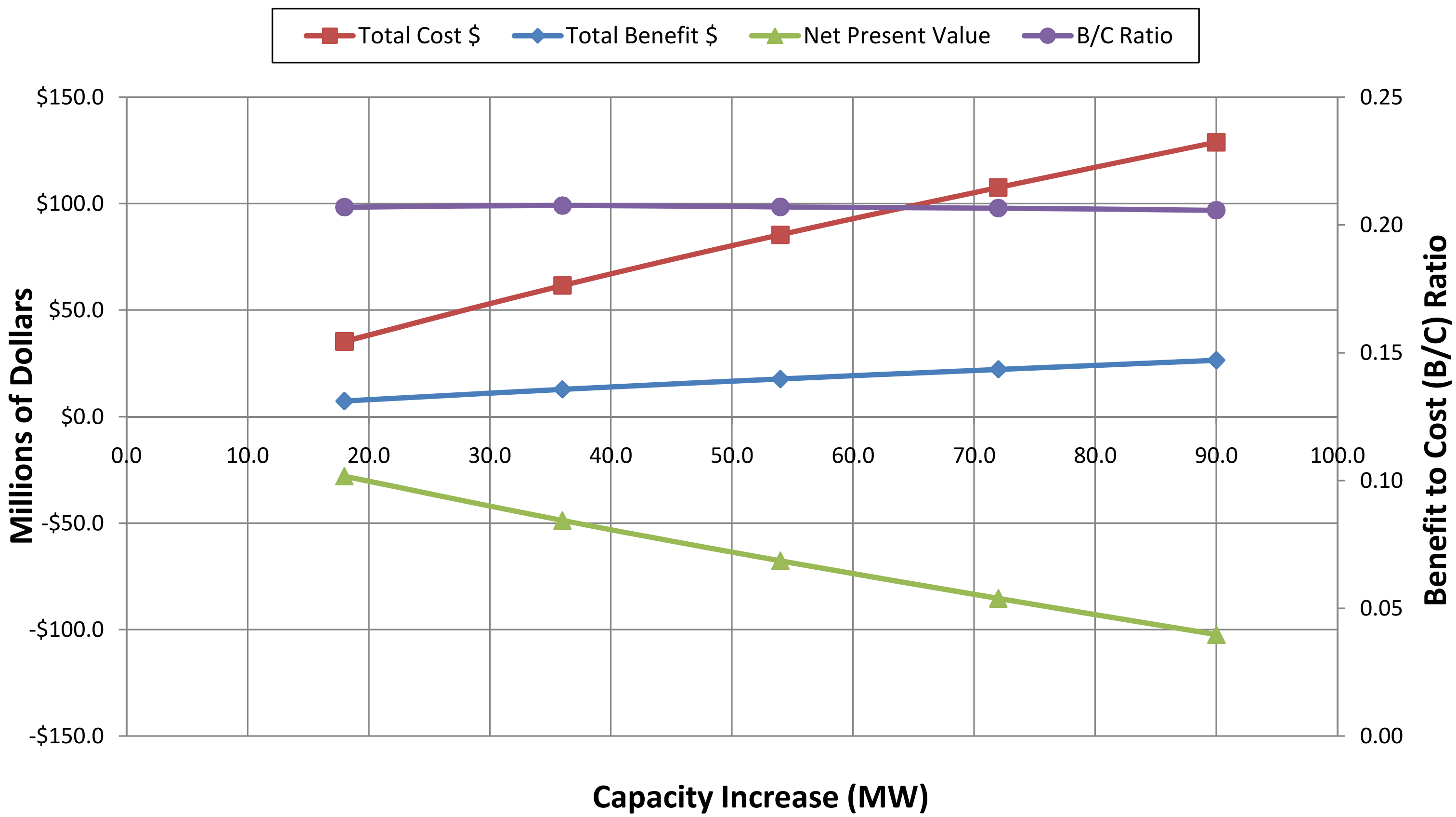
Summary of Capacity Increase Benefits and Costs
Spirit Mountain

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	0.5	0	0%	$1.3	$2,797	$1.9	$0.0	$0.1	$0.1	-$1.8	0.05
20%	0.9	0	0%	$2.2	$2,438	$3.2	$0.0	$0.2	$0.2	-$3.1	0.06
30%	1.4	0	0%	$3.0	$2,254	$4.5	$0.0	$0.3	$0.3	-$4.2	0.06
40%	1.8	0	0%	$3.8	$2,133	$5.6	$0.0	$0.4	$0.4	-$5.3	0.06
50%	2.3	0	0%	$4.6	$2,044	$6.7	$0.0	$0.4	$0.4	-$6.3	0.07



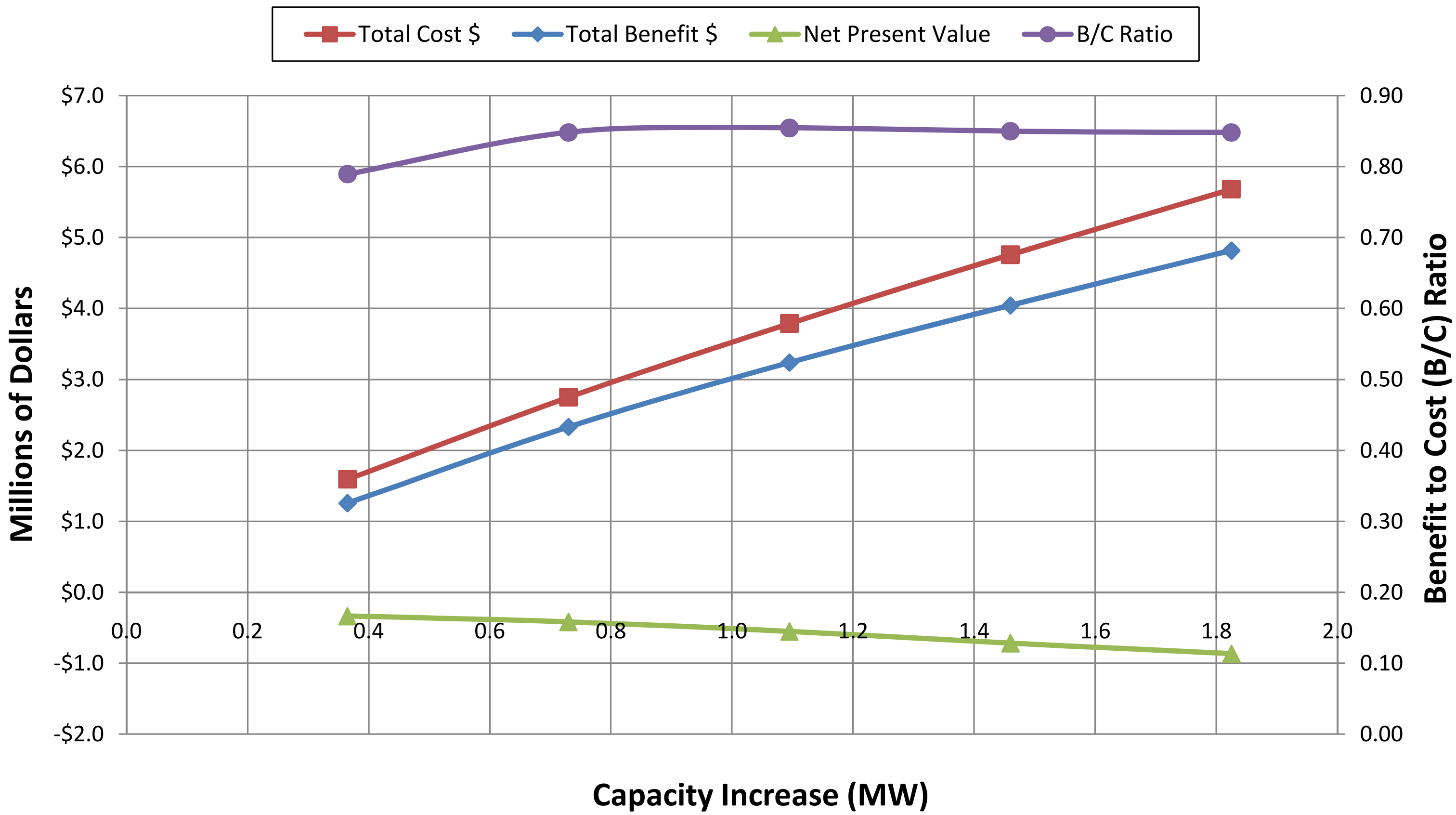
Summary of Capacity Increase Benefits and Costs
Spring Creek

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	18.0	1,499	1%	$25.1	$1,395	$35.3	$2.7	$4.6	$7.3	-$28.0	0.21
20%	36.0	2,260	1%	$44.4	$1,234	$61.6	$4.0	$8.7	$12.8	-$48.8	0.21
30%	54.0	2,783	1%	$62.1	$1,150	$85.3	$5.0	$12.7	$17.7	-$67.6	0.21
40%	72.0	3,173	1%	$78.8	$1,094	$107.6	$5.7	$16.5	$22.2	-$85.4	0.21
50%	90.0	3,450	0%	$94.7	$1,053	$128.8	$6.2	$20.3	$26.5	-$102.3	0.21



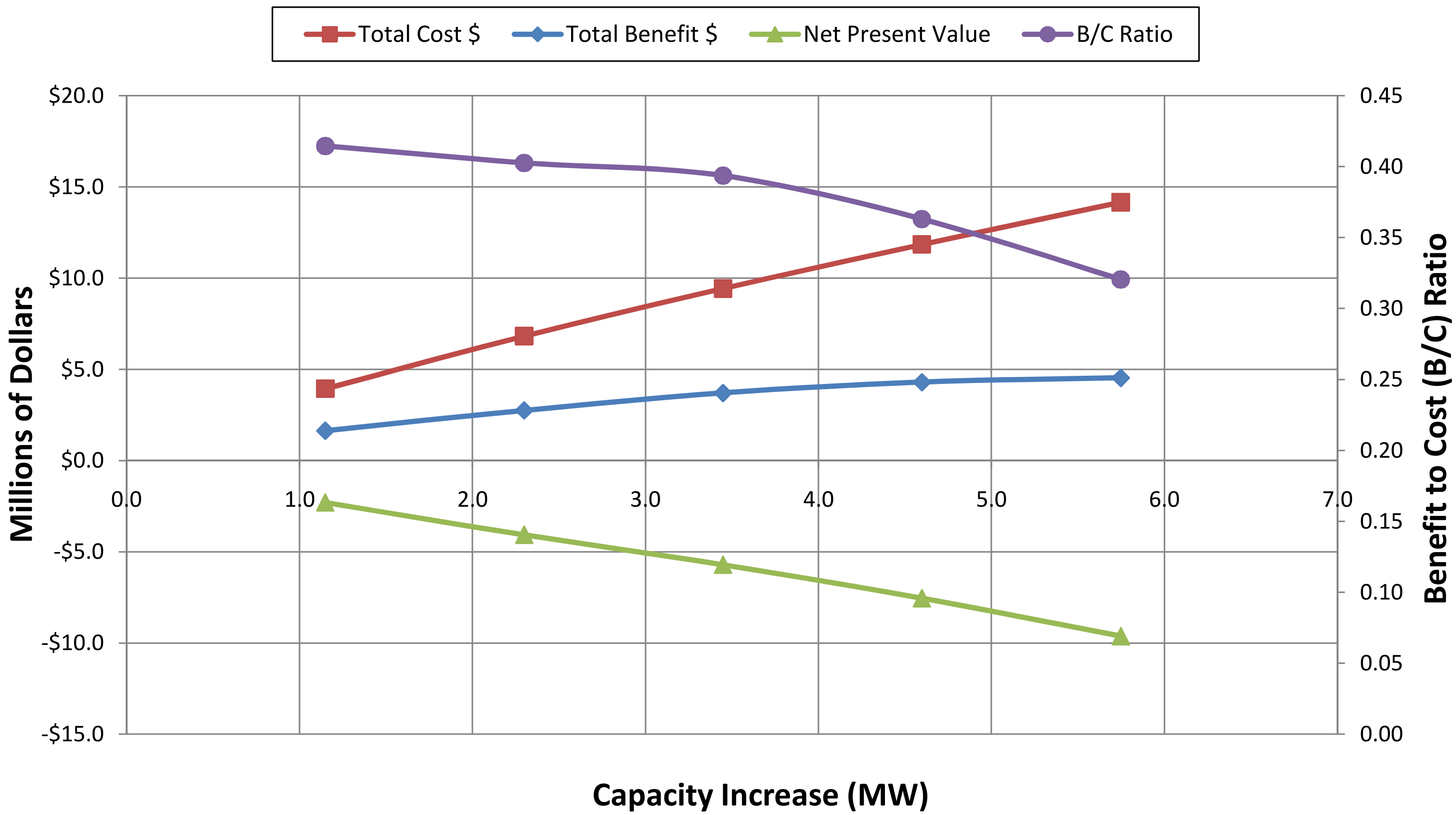
Summary of Capacity Increase Benefits and Costs
Stampede

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	0.4	568	18%	$1.1	$2,918	$1.6	$0.8	$0.5	$1.3	-$0.3	0.79
20%	0.7	1,050	16%	$1.9	$2,540	$2.7	$1.5	$0.9	$2.3	-$0.4	0.85
30%	1.1	1,449	15%	$2.6	$2,347	$3.8	$2.0	$1.2	$3.2	-$0.6	0.85
40%	1.5	1,801	14%	$3.2	$2,220	$4.8	$2.5	$1.5	$4.0	-$0.7	0.85
50%	1.8	2,138	13%	$3.9	$2,127	$5.7	$3.0	$1.8	$4.8	-$0.9	0.85



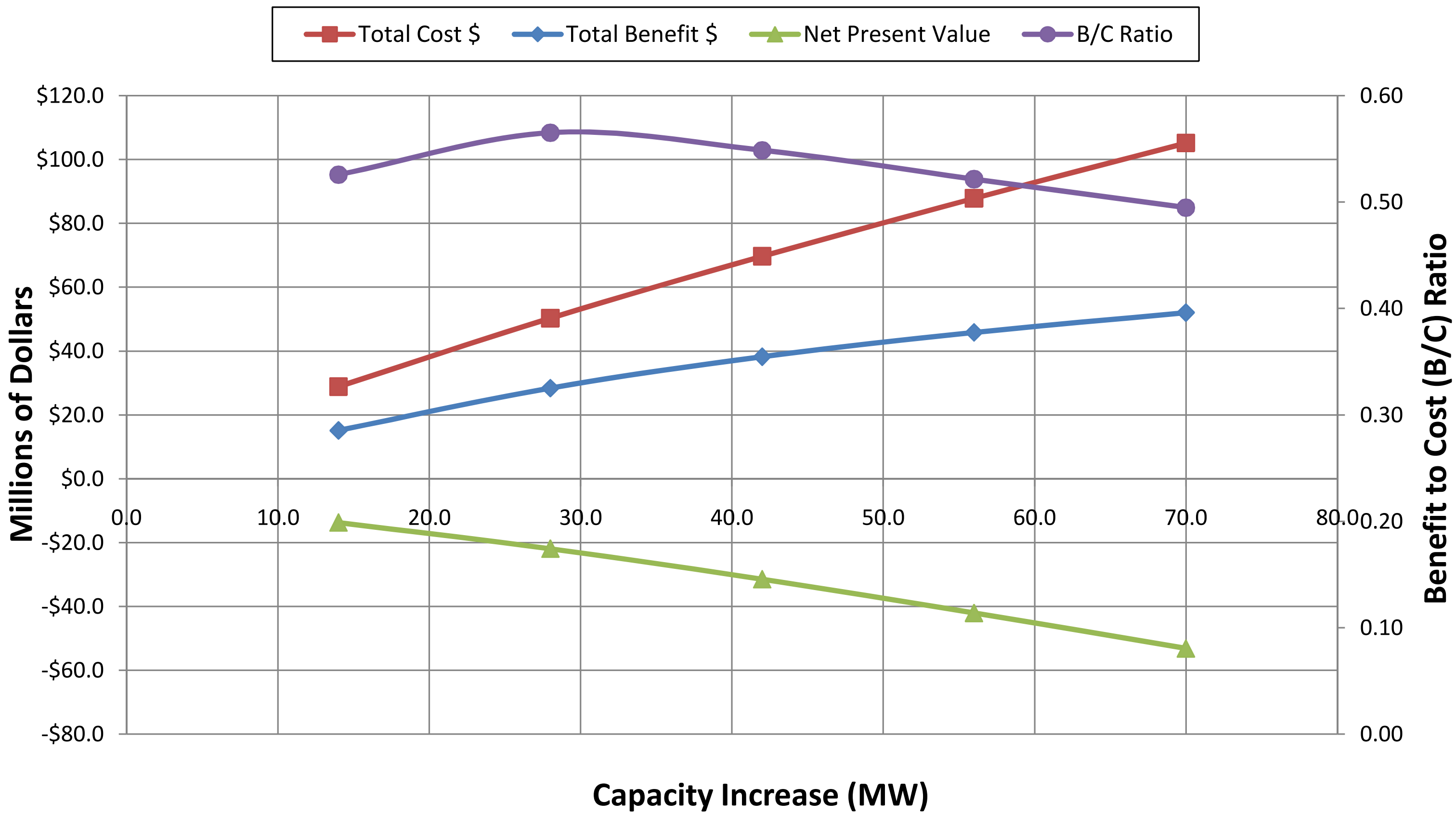
Summary of Capacity Increase Benefits and Costs
Towaoc

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	1.1	797	8%	$2.7	$2,325	$3.9	$0.9	$0.8	$1.6	-$2.3	0.41
20%	2.3	1,300	6%	$4.7	$2,036	$6.8	$1.4	$1.3	$2.7	-$4.1	0.40
30%	3.4	1,715	6%	$6.5	$1,886	$9.4	$1.8	$1.9	$3.7	-$5.7	0.39
40%	4.6	1,922	5%	$8.2	$1,788	$11.8	$2.1	$2.2	$4.3	-$7.5	0.36
50%	5.7	1,925	4%	$9.9	$1,716	$14.2	$2.1	$2.5	$4.5	-$9.6	0.32



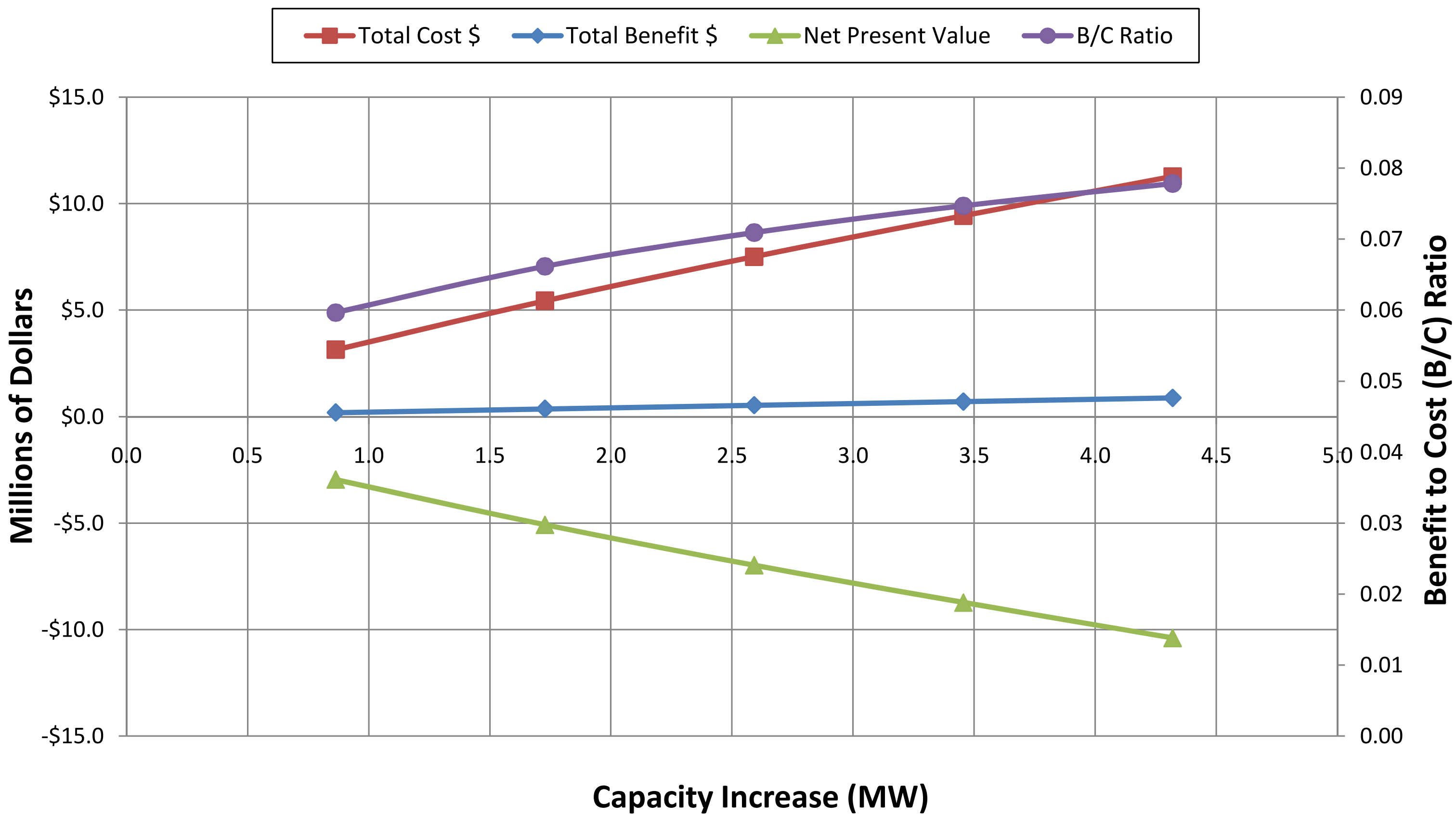
Summary of Capacity Increase Benefits and Costs
Trinity

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	14.0	4,999	4%	$20.4	$1,459	$28.8	$8.9	$6.2	$15.2	-$13.7	0.53
20%	28.0	9,229	4%	$36.1	$1,290	$50.3	$16.5	$11.9	$28.4	-$21.9	0.57
30%	42.0	12,066	3%	$50.4	$1,201	$69.7	$21.6	$16.6	$38.2	-$31.5	0.55
40%	56.0	14,002	3%	$64.0	$1,142	$87.8	$25.1	$20.8	$45.8	-$42.0	0.52
50%	70.0	15,384	3%	$76.9	$1,099	$105.2	$27.5	$24.5	$52.0	-$53.1	0.49



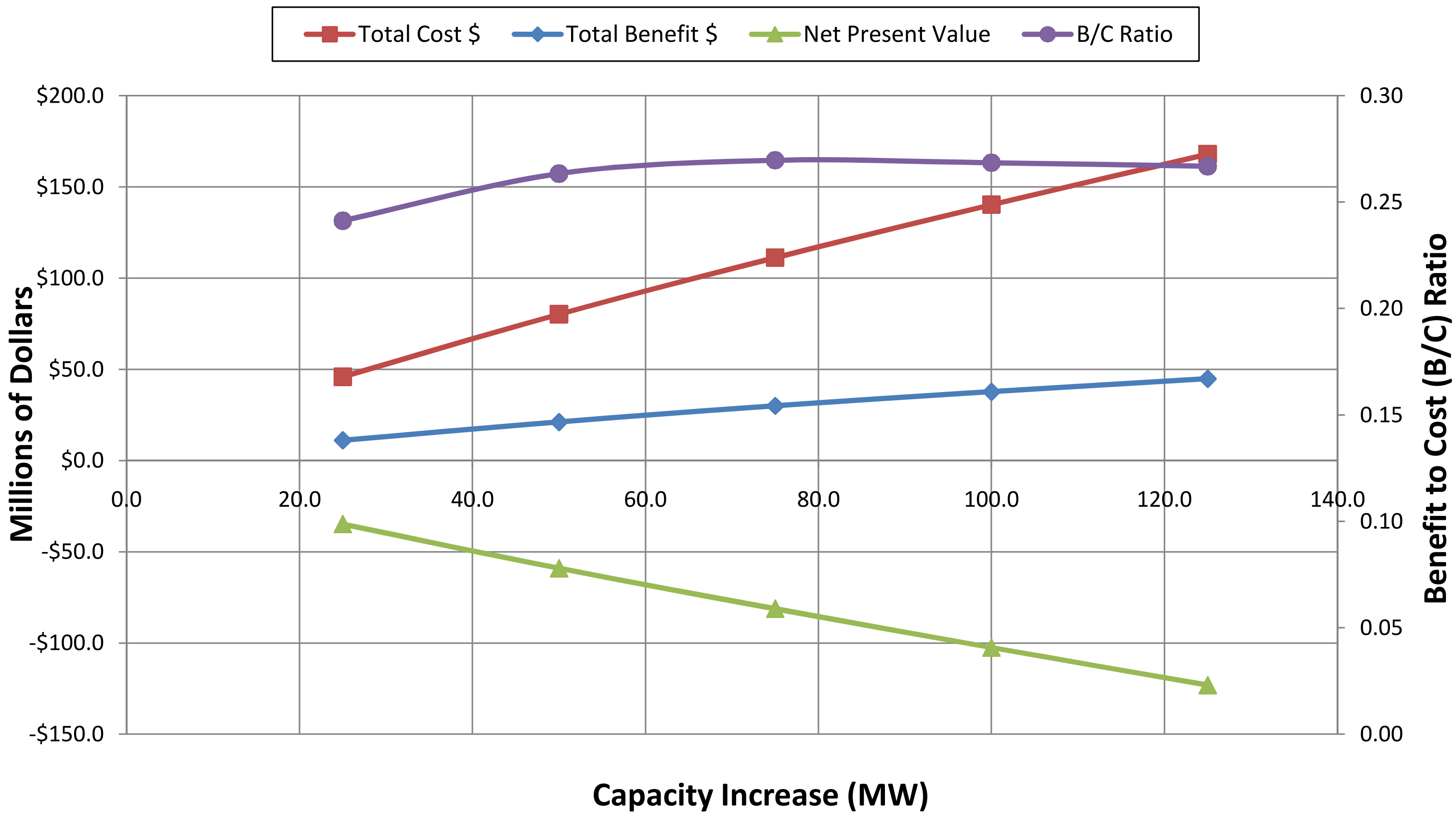
Summary of Capacity Increase Benefits and Costs
Upper Molina

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	0.9	8	0%	$2.1	$2,458	$3.1	$0.0	$0.2	$0.2	-$3.0	0.06
20%	1.7	8	0%	$3.7	$2,149	$5.4	$0.0	$0.4	$0.4	-$5.1	0.07
30%	2.6	8	0%	$5.2	$1,990	$7.5	$0.0	$0.5	$0.5	-$7.0	0.07
40%	3.5	8	0%	$6.5	$1,885	$9.4	$0.0	$0.7	$0.7	-$8.7	0.07
50%	4.3	8	0%	$7.8	$1,809	$11.3	$0.0	$0.9	$0.9	-$10.4	0.08



Summary of Capacity Increase Benefits and Costs
Yellowtail

Percent Capacity Increase	Capacity Increase (MW)	Average Incremental Energy (MWh/yr)	Total Incremental Capacity Factor	Construction & Mitigation Total Cost ($M)	Construction & Mitigation Total Cost ($/kW)	PV of Total Costs ($M)	PV of Energy Benefits ($M)	PV of Capacity Benefits ($M)	PV of Total Benefits ($M)	NPV of Total Benefits ($M)	B/C Ratio
10%	25.0	3,458	2%	$32.9	$1,316	$45.9	$3.7	$7.4	$11.1	-$34.8	0.24
20%	50.0	6,327	1%	$58.3	$1,165	$80.2	$6.8	$14.3	$21.1	-$59.1	0.26
30%	75.0	8,526	1%	$81.5	$1,086	$111.2	$9.2	$20.8	$30.0	-$81.2	0.27
40%	100.0	10,049	1%	$103.4	$1,034	$140.2	$10.8	$26.8	$37.6	-$102.6	0.27
50%	125.0	11,286	1%	$124.4	$995	$167.9	$12.1	$32.7	$44.8	-$123.1	0.27



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