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Missouri River Recovery Management Plan and Environmental Impact Statement

MISSOURI RIVER RECOVERY PROGRAM

HYDROPOWER ENVIRONMENTAL CONSEQUENCES ANALYSIS TECHNICAL REPORT

December 2016

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Missouri River Recovery Management Plan and Environmental Impact Statement

Hydropower
Environmental Consequences Analysis

Technical Report

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Acronyms and Abbreviations

BiOp	2003 Amended Biological Opinion
Corps	U.S. Army Corps of Engineers
DSS	Data Storage System
EIS	Environmental Impact Statement
EQ	Environmental Quality
ER	Environmental Regulation
ESH	Emergent Sandbar Habitat
H&H	Hydrologic and Hydraulic (Model)
HEC	USACE Hydrologic Engineering Center
M&I	municipal and industrial
MRRIC	Missouri River Recovery Implementation Committee
MRRP	Missouri River Recovery Program
NED	National Economic Development
OSE	Other Social Effects
P&G	1983 Economic and Environmental Principles and Guidelines For Water And Related Land Resources Implementation Studies
RAS	River Analysis System
RED	Regional Economic Development
ResSim	Reservoir System Simulation
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service

1.0 Introduction

The USACE in cooperation with the USFWS are developing a Missouri River Recovery Management Plan and Draft Environmental Impact Statement (MRRMP Draft EIS). The purpose of the MRRMP Draft EIS is to develop a management plan that includes a suite of actions that removes or precludes jeopardy status for the piping plover, the interior least tern, and the pallid sturgeon using USACE authorities.

The purpose of the Hydropower Environmental Consequences Analysis Technical Report is to provide supplemental information on the hydropower analysis and results in addition to the information presented in the MRRMP-EIS. Additional details on the National Economic Development (NED), Regional Economic Development (RED), and Other Social Effects (OSE) methodology and results are provided in this technical report. No Environmental Quality (EQ) analysis was undertaken for hydropower.

1.1 Summary of Alternatives

The MRRMP Draft EIS evaluates the following Management Plan alternatives. Detailed description of the alternatives is provided in the Draft EIS, Chapter 2.

- **Alternative 1 – No Action.** This is the no-action alternative, in which the Missouri River Recovery Program (MRRP) would continue to be implemented as it is currently, including a number of management actions associated with the MRRP and BiOp compliance. Management actions under No Action include creation of early life stage habitat for the pallid sturgeon and emergent sandbar habitat (ESH), as well as a spring plenary pulse. The construction of habitat will be focused in the Garrison and Gavins reaches for ESH (an average rate of 107 acres per year) and between Ponca to the mouth near St. Louis for early life stage habitat (3,999 additional acres constructed).
- **Alternative 2 – USFWS 2003 Biological Opinion Projected Actions.** This alternative represents the USFWS interpretation of the management actions that would be implemented as part of the 2003 Amended BiOp Reasonable and Prudent Alternative (USFWS, 2003). Whereas No Action only includes the continuation of management actions USACE has implemented to date for BiOp compliance, Alternative 2 includes additional iterative actions and expected actions that the USFWS anticipates would ultimately be implemented through adaptive management and as impediments to implementation were removed. Considerably more early life stage habitat (10,758 additional acres constructed) and ESH (an average rate of 3,546 acres per year) would be constructed under Alternative 2 than under Alternative 1. In addition, a spring pallid sturgeon flow release would be implemented every year if specific conditions were met. Alternative 2 would also modify System operations to allow for summer flows that are sufficiently low to provide for early life stage habitat as rearing, refugia, and foraging areas for larval, juvenile, and adult pallid sturgeon.
- **Alternative 3 – Mechanical Construction.** The USACE would only create ESH through mechanical means at an average rate of 391 acres per year across the entire system. This amount represents the acreage necessary to meet the bird habitat targets after accounting for available ESH resulting from system operations. The average annual construction amount includes replacing ESH lost to erosion and vegetative growth, as well as constructing new ESH. An additional 3,380 acres of early life stage habitat for the

pallid sturgeon would be constructed under Alternative 3. There would not be any reoccurring flow releases or pulses implemented under this alternative.

- **Alternative 4 – Spring ESH Creating Release.** The USACE would mechanically construct ESH annually at an average rate of 240 acres per year across the entire system. This amount represents the acreage necessary to meet the bird habitat targets after accounting for available ESH resulting from implementation of an ESH-creating reservoir release in the spring. Alternative 4 would be similar to Alternative 1 (current operations), with the addition of a spring release designed to create ESH for the least tern and piping plover. An additional 3,380 acres of early life stage habitat for the pallid sturgeon would be constructed under Alternative 4.
- **Alternative 5 – Fall ESH Creating Release.** The USACE would mechanically construct ESH annually at an average rate of 309 acres per year across the entire system. This alternative is based on Alternative 1 (current operations), with the addition of a release in the fall designed to create sandbar habitat for the least tern and piping plover. An additional 3,380 acres of early life stage habitat for the pallid sturgeon would be constructed under Alternative 5.
- **Alternative 6 – Pallid Sturgeon Spawning Cue.** The USACE would mechanically construct ESH annually at an average rate of 303 acres per year across the entire system. In addition, the USACE would attempt a spawning cue pulse every three years in March and May. These spawning cue pulses would not be started or would be terminated whenever flood targets are exceeded. An additional 3,380 acres of early life stage habitat for the pallid sturgeon would be constructed under Alternative 6.

1.2 USACE Planning Accounts

Alternative means of achieving species objectives were evaluated including consideration for the effects of each action or alternative on a wide range of human considerations (HC). Human considerations to be evaluated in the MRRMP-EIS alternatives are rooted in the economic, social, and cultural values associated with the natural resources of the Missouri River. The HC effects evaluated in the MRRMP Draft EIS are required under the National Environmental Policy Act and its implementing regulations (40 CFR Parts 1500-1508). The 1983 Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies (P&G) also served as the central guiding regulation for the economic and environmental analysis included within the MP-EIS. Further guidance that is specific to USACE is described in Engineering Regulation (ER) 1105-2-100, Planning Guidance Notebook, which provides the overall direction by which USACE Civil Works projects are formulated, evaluated, and selected for implementation. These guidance documents describe four accounts that were established to facilitate evaluation and display the effects of alternative plans:

- The national economic development (NED) account displays changes in the economic value of the national output of goods and services expressed in monetary units. Contributions to NED are the direct net benefits that accrue in the planning area and the rest of the Nation.
- The regional economic development (RED) account registers changes in the distribution of regional economic activity (i.e. jobs and income).
- The environmental quality (EQ) displays non-monetary effect of significant natural and cultural resources.

- The other social effects (OSE) account registers plan effects from perspective that are relevant to the planning process, but are not reflected in the other three accounts. In a general sense, OSE refers to how the constituents of life that influence personal and group definitions of satisfaction, well-being, and happiness are affected by some condition or proposed intervention.

The accounts framework enables consideration of a range of both monetary and non-monetary values and interests that are expressed as important to stakeholders, while ensuring impacts are not double counted. The USACE planning accounts evaluated for thermal power include NED, RED, and OSE.

1.3 Approach for Evaluating Environmental Consequences of Missouri River Recovery Management Plan

The conceptual flow chart shown in Figure 1 demonstrates, in a stepwise manner, how changes to the physical conditions of the Missouri River and its floodplain can lead to changes to the objectives associated with Hydropower. This figure also shows the intermediate factors and criteria that were applied in assessing consequences to hydropower.

Hydropower has two important connections with the physical components of the Missouri River watershed: river flows/dam releases and reservoir elevations. The type and amount of dam release directly affects the amount of hydropower generated and can be a function of total water stored in the system. In addition, reservoir elevations can influence the efficiency of turbines and hydropower plants, also impacting the levels of hydropower produced at each facility. Reservoir elevations for all the reservoirs describe the water in system storage, which may affect dam releases. Changes in physical conditions could affect the hydropower system performance, including system hydropower generation, load following capability, plant efficiency, reliability to meet peak demands during critical months, and flexibility to perform ancillary services. (Ancillary services are services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such activities may include load regulation, spinning reserve, non-spinning reserve, replacement reserve, dark start, and voltage support.)

All of these potential changes in hydropower performance could affect the amount of surplus power generated, the need to purchase additional power to meet contract obligations, and changes in reliance on thermal power energy sources. These changes could affect energy and capacity values, which are described in EM 1110-2-1701 Hydropower Manual. These values are based on the most likely thermal alternative, utilizing updated thermal cost projections. The energy/capacity price is based on the cost of energy from a combination of thermal generation plant types that would replace the lost energy/capacity from the hydropower plant due to operational and/or structural changes. The value of this energy is associated with its ability to meet demand. For example, higher price generating resources may only be utilized to meet peak demand. Energy and capacity have both regional and seasonal values. It is possible during the peak summer months that low flows may reduce both hydropower and replacement thermal generation.

CHANGES IN: Physical components of the Missouri River watershed

- Water storage in system (reservoir elevations)
- River flows

Lead To

CHANGES IN: Hydropower System Performance

- Load following capability (hourly, seasonally)
- Total System generation/total plant generation
- Plant efficiency
- Reliability to meet peak demands during critical months
- Flexibility to provide ancillary services

Lead To

CHANGES IN: Hydropower Activity

- Surplus Energy
- Purchased power
- Changes in reliance on alternative (thermal) resources for firm power
- Rate impacts
- Changes to transmission system operation costs and utilization

Lead To

CHANGES IN: Beneficial Effects and/or Costs

- National Economic Development (NED) – Energy and Capacity Values

Lead To

CHANGES IN: Benefits

- Regional Economic Development (RED) – changes to preference customers' rates, household spending, business activity, and other government programs

Lead To

CHANGES IN: Benefits

- Other Social Effects (OSE) – Air emissions from reliance on alternative sources and system reliability

Figure 1. Flow Chart of Inputs Considered in Hydropower Evaluation

The one-time spawning cue test (Level 2) release that may be implemented under Alternatives 3, 4, and 5 was not included in the hydrologic modeling for these alternatives because of the uncertainty of the hydrologic conditions that would be present if implemented. Hydrologic modeling for Alternative 6 simulates reoccurring implementation (Level 3) of this spawning cue over the wide range of hydrologic conditions in the POR. Therefore, the impacts from the potential implementation of a one-time spawning cue test release would be bound by the range of impacts described for individual releases under Alternative 6.

2.0 Methodology and Assumptions

2.1 Methodology

Evaluation of the environmental consequences of the Management Plan requires an understanding of how the physical conditions of the river would change under each of the Management Plan alternatives. This initial first step is critical for evaluating Human Consideration (HC) impacts and those specified in the four accounts. Figure 2 shows the overall approach used to evaluate the consequences to Hydropower from Management Plan alternatives.

The following sections provide further details on the methodology.

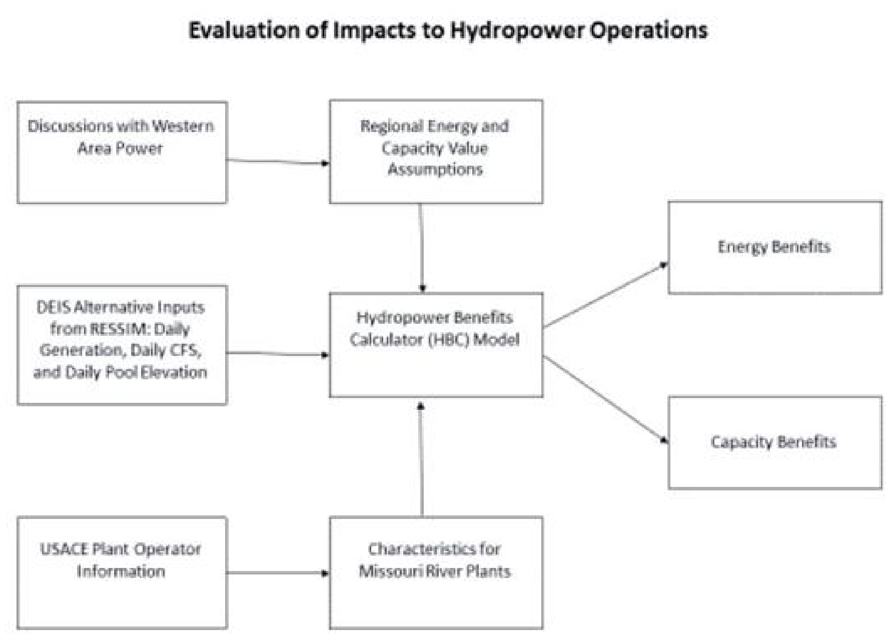


Figure 2. Approach for Evaluating Consequences to Hydropower

The flow chart shows the data necessary to run the Hydropower Benefits Calculator (HBC). This includes discussions with plant operators to get information on plant characteristics and operations and conversations with Western Area Power Administration (WAPA) to determine the appropriate regional energy and capacity value assumptions. This information, along with ResSim elevation and flow inputs for each of the alternatives, is fed into the HBC model. From there, the model calculates energy benefits and capacity benefits, which can then be compared across alternatives.

2.2 Assumptions

In modeling the environmental consequences to hydropower from the MRRMP for the draft EIS, the project team established a set of assumptions. The important assumptions used in the modeling effort are as follows.

- The economic analyses use data from the hydrologic and hydraulic (H&H) modeling of the river and reservoir system. The analysis assumes that the H&H models reasonably estimate river flows and reservoir levels over the 82-period of record under each of the MRRMP-EIS alternatives as well as Alternative 1 (No Action).
- A 2016 estimated EIA energy price was used in conjunction with the historic pattern of energy prices to determine specific blocks of hourly, daily, and monthly prices. Capacity unit values were determined using a screening curve analysis that plots annual total plant costs for different types of thermal generating plants (fixed capacity cost plus variable operating costs) versus an annual plant factor. The final capacity value is a mix of the least cost alternative sources for each plant factor range. Please see the Energy and Capacity Values section below for more detailed information on the values used in this analysis.
- Some tables presented below were created using spreadsheet software. Arithmetic operations and totals were taken to full decimal accuracy within the spreadsheet. Some tables within this report have been rounded after the mathematical computations were performed; as a consequence, rounded totals may not equal the summation of rounded values.

3.0 National Economic Development Analysis

National Economic Development (NED) effects are defined as changes in the net value of the national output of goods and services. In the case of Hydropower, the conceptual basis for the NED impacts analysis is society's willingness to pay for the increase or decrease in the value of goods attributable to Hydropower.

The measurement of national economic effects can be based on estimated changes in energy and capacity values of existing hydropower facilities that would result from Management Plan alternatives. Replacement energy is computed as the product of energy loss in megawatt-hours and the energy unit value price ($/MWh). Replacement capacity is computed as the product of dependable capacity lost in MW and a capacity unit value (dollars/MW) representing the value of the most likely thermal alternative. The National Economic Development benefits for hydropower are based on the accrued cost of the most likely alternative energy source that would replace reduced hydropower generation (energy and capacity).

3.1 Approach

The Hydropower Benefits Calculator (HBC) model was used for calculating NED benefits for this study. This model was developed by the USACE's Hydropower Analysis Center (HAC) in early 2014 for use in Missouri River studies.

The Missouri River HBC model is a post-processor of a flow routing model, daily time step, used to calculate NED hydropower benefits. This model is a series of functions written in the Matlab programming language. The functions themselves are not written specifically for the Missouri River System. Instead the functions read a series of input files that define specific Missouri River characteristics. This provides the user transparency to model parameters, easy adjustment, and adaptability to other systems including the addition of new plants.

Version 1.0 of the Missouri River HBC calculates NED Hydropower benefits as defined by the ER 1105-2-100 Planning Guidance Notebook (22 April 2000) for planning-level studies. The model area focuses on the six USACE dams and their associated reservoirs located on the Missouri River mainstem, including Fort Peck, Garrison, Oahe, Big Bend, Fort Randall, and Gavins Point.

The model is categorized as a Regional/Local Model as it was conceived to address unique situations and calibrated to specific characteristics for studies related to Missouri River hydropower plants. More details describing a Regional/Local Model can be found in the EC 1105-2-412 entitled, Assuring Quality of Planning Models.

This HBC model acts as a post-processor to the daily time step routing model, HEC Reservoir System Simulation (HEC-ResSim). Outputs required from ResSim model include daily flow and reservoir elevations. As the ResSim model simulates management alternatives, the HBC model uses this output to compute two NED benefits:

1. Energy Benefits: is the product of the energy loss in megawatt-hours and an energy unit value price ($/MWh). The megawatt-hours loss is estimated based upon the change in water elevation and flow, while the cost of energy is estimated based on the cost of energy from a combination of plants that could provide replacement energy.

2. Dependable Capacity Benefits: The dependable capacity of a hydropower project is a measure of the amount of capacity that the project can reliably contribute towards meeting system peak power demands. Dependable capacity benefit is computed as the product of the systems dependable capacity (MW) and a composite unit capacity value ($/MW) that reflects the most likely thermal power generation alternative.

3.1.1 Inputs/Outputs for the HBC Model

The HBC model consists of a number of input files. A brief categorization of these files is given below:

1. Hydrological Inputs - Daily flow and reservoir elevations modeled by the HEC-ResSim routing model.

2. Plant System Files-Plant characteristics for each of the six mainstem dams such as Turbine efficiency tables, tailwater rating curves, maximum and minimum plant hydraulic capacity (source: USACE)

3. Calibrated Parameters – Parameters such as optimization weights and generator efficiency calibrated to minimize error between observed and simulated results (source:calculated)

4. Economic Inputs-Regional energy, capacity, and revenue values. Currently these inputs are created outside of the HBC using Excel spreadsheets from sources such as Southwest Power Pool (SPP) and the Energy Information Administration (EIA).

The HBC model consists of a number of output files. A brief categorization of these files is given below:

1. Modeled Hydrologic Output: Hourly modeled flow, tailwater elevation, and hydraulic head.

2. Modeled Energy Output: Hourly modeled generation, turbine efficiency, critical year dependable capacity values, generation roll up tables

3. Benefits Data: Modeled plant level dependable capacity tables, energy value roll up tables, revenue foregone rollup tables

4. Calibration Files: Performance metrics results for comparing simulated versus observed flow and energy values

5. Model Verification Files: Several result files that look at key modeled values to ensure reliability in the calculations.

The HBC model includes the following Matlab functions:

1. Hourly Energy Simulation. Takes hydrological inputs from routing model and shapes average daily flows into hourly values. Hourly generation values are then computed using the power equation. The output from this function is hourly flow and generation values for the modeled period of record.

2. Critical _Year_hours. This function calculates the number of hours a plant can run at full capability averaged over critical months for a critical year.

3. Dependable Capacity Calculator. This function takes as input the number of hours a plant can run at full capability calculated in the critical_year_hours.m file and computes the plants average capability operating for defined hours during the critical months over the entire modeled period of record. Output of this function is each plants dependable capacity.

4. Energy Benefits Calculator. This function takes as input hourly generation data calculated by the Hourly_Energy_Simulation.m file. The function then distinguishes the generation data into six blocks of decreasing generation values, assigning the respective Energy Replacement Values. Output of this function is monthly roll ups of energy replacement value for each plant.

5. Revenue Foregone Calculator. This function rolls up the hourly data calculated in the Hourly_Energy_Simulation.m file into an annual total generation value. These values are then assigned a constant rate based on the current Power Marketing Administration (PMA) contracts. The output from this function is the current revenue expected for each modeled year.

3.1.2 Data Collection

The main input to the HBC model consists of daily reservoir elevations and average flows for the six mainstem dams on the Missouri River, which is provided by the HEC-ResSim routing model. The use of this model requires both historic hydrologic and generation data. The hydrologic data required consists of hourly flow distributions and daily reservoir elevations. The required generation data is hourly generation data. The current version of the HBC model uses six representative years of generation and hydrologic data collected from the USACE NWO district. Six representative years are considered to reflect current hourly operating patterns.

Additional data is needed for the HBC model. Specific plant level hydropower data requirements include turbine efficiency and tailwater rating curves, which have been collected from the USACE Hydropower Center of Expertise, the Hydropower Design Center (HDC). Plant level constraints such as minimum and maximum monthly hydraulic capacity values (upper and lower plant level flow limits) are obtained from Missouri River Water Control Manual.

Economic inputs to the HBC model are readily available from the EIA's and SPP's websites.

3.1.3 Energy Values

The energy benefits calculator function of the HBC computes annual energy benefits for alternatives. In general, energy benefits are calculated as the product of energy generation and an appropriate energy price in terms of $/MWh. The energy prices used are based on the cost of energy from a combination of generation plants that would replace the lost energy from the hydropower plant due to operational and/or structural changes.

Energy prices vary from hour to hour, between weekdays and weekends, and between different months. One difficulty of computing energy benefits associated with replacing hydropower is associating the lost hourly energy generation with the appropriate replacement energy price. One simplifying assumption is that high hourly energy prices are associated with high hourly generation periods. This assumption is reasonable because economical dispatch during periods of peak demand require adding higher cost generating resources required to meet system load. However, PMAs generate to meet customers loads that may not completely relate to the overall block load. The HBC does make this simplifying assumption and associates high energy price blocks with high generation blocks. Energy blocks in the HBC model are periods of 4 hours sorted from high generation periods to low generation periods.

Since energy prices change hourly, daily, and seasonally, quantifying lost hydropower energy benefits requires forecasting when hydropower energy benefits will be lost and the associated replacement energy pricing variability. The energy values for the Missouri River are best estimated using the Locational Marginal Pricing (LMP) from the WAUE hub of the SPP. LMP is a computation technique that determines a shadow price for an additional MWh of demand. Historical LMP values for WAUE were downloaded from the SPP website.

Since LMP provides historical pricing it was utilized in combination with information from the Energy Information Administration (EIA) to develop an energy price forecast. Each year the EIA publishes an Annual Energy Outlook (AEO) that lists thirty years of forecasted energy costs of different electric market modules. The AEO also lists actual energy prices for three historical years. The energy price forecast is split into three categories; generation, transmission, and distribution. For this study, the EIA generation forecast for the Midwest Reliability Council West was used to forecast future LMP values for this study.

To shape the values the following ratio is assumed:

$$\frac{LMP_{Future}}{LMP_{Past}} = \frac{EIA\_Generation_{Future}}{EIA\_Generation_{Past}}$$

Which can be rewritten as:

$$LMP_{Future} = EIA\_Generation_{Future} * \frac{LMP_{Past}}{EIA\_Generation_{Past}}$$

The future LMP values can then be computed by the product of the EIA generation forecast and a shaping ratio defined as:

$$ShapingRatio = \frac{LMP_{Past}}{EIA\_Generation_{Past}}$$

As explained above, the unique shaping ratio is defined to reflect hourly, weekly, and seasonal variability. Daily LMP values can be sorted from high to low, similar to the sorting of hourly generation. This produces the hourly ranked shaping ratios. Weekly variability is considered by computing shaping ratios for weekends and weekdays. Finally seasonal variability is taken into account by computing shaping ratios for each month. These shaping ratios are computed as averages with like hourly rankings, month and weekday classification using the equation:

$$ShapingRatio(weekday, month, hourly\_ranking) = Average\left(\frac{LMP_{Past}(weekday, month, hourly\_ranking, year)}{EIA\_Generation_{Past}(year)}\right)$$

The shaping rations are then averaged for each four hour block:

$$ShapingRatio_{block=i}(weekday, month) = Average(ShapingRatio(weekday, month, hourly\_ranking))$$

This produces the following equation to compute LMP forecasts for block 1 through 6, weekends, and for each month.

$$LMP_{Future}(block = i, weekday, month) = EIA\_Generation_{Future} * ShapingRatio_{block=i}(weekday, month)$$

It should also be noted that to calculate the average annual energy benefits, the EIA generation thirty year price forecast is annualized to a single number and then applied to the shaping ratios. The tables below shows the energy prices ($/MWh) used for this analysis.

Table 1. Estimated 2016 Monthly, Weekend and Weekday, and Block Energy Values

Weekday Energy Values												
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Block 1	50.24344	62.18667	58.54202	45.76401	48.39157	41.08303	41.3345	45.81533	31.20308	35.12515	37.23776	33.1646
Block 2	35.31784	46.98111	42.614	36.3262	41.61093	34.40736	35.3412	36.66199	27.16139	31.16443	29.11232	28.55086
Block 3	31.03127	40.37559	34.17997	32.17981	35.81298	28.35345	30.2129	29.6003	23.60319	28.29419	24.80372	25.89494
Block 4	27.46231	33.70687	29.13073	28.86298	30.11389	21.87124	23.20875	22.53905	20.11306	24.36586	21.68259	23.32139
Block 5	23.47263	28.81493	23.94921	21.37374	20.34774	15.8784	17.02064	17.32071	14.88301	16.95248	17.88491	19.77366
Block 6	19.52044	23.14328	19.69126	15.9329	16.23034	13.91257	15.05835	15.20692	12.51328	13.6404	13.71333	16.85761
Weekend Energy Values												
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Block 1	34.17206	47.28003	47.7413	38.93668	43.96208	37.7393	43.71824	40.53865	30.22948	32.61383	29.82731	29.26376
Block 2	26.02145	36.55437	35.09748	30.27328	37.6892	30.62098	34.77158	31.09655	26.83473	26.48109	22.60597	22.92456
Block 3	23.67184	30.48354	29.17248	26.7515	31.8428	24.91397	28.28257	25.46217	23.15263	22.85506	19.88386	21.11111
Block 4	21.14352	26.50942	25.50866	22.64422	24.82935	18.17931	19.8122	19.66145	18.72588	19.59756	17.53717	19.57887
Block 5	19.72342	24.53506	19.92848	17.29848	17.27988	14.48323	14.84257	16.02801	15.30163	15.39158	14.43334	17.24533
Block 6	17.79871	22.02075	17.0078	12.76776	15.88181	12.89515	13.42101	14.9821	13.42656	13.38188	12.33102	15.31156

3.1.4 Capacity Values

The dependable capacity of a hydropower project is a measure of the amount of capacity that the project can reliably contribute towards meeting system peak power demands. If a hydropower project always maintains approximately the same head, and there is always an adequate supply of stream flow so that there is enough generation for the full capacity to be usable in the system load, the full installed generator capacity can be considered dependable. In some cases even the overload capacity is dependable.

At storage projects, normal reservoir drawdown can result in a reduction of capacity due to a loss in head. At other times, diminished stream flows during low flow periods may result in insufficient generation to support the marketable capacity of the load. Dependable capacity accounts for these factors by giving a measure of the amount of capacity that can be provided on average during peak demand periods.

In order to develop a value for capacity, a screening curve analysis was used. A screening curve is a plot of annual total plant costs for a thermal generating plant (fixed (capacity) cost plus variable (operating) cost) versus an annual plant factor (plant utilization factor). When this is applied to multiple types of thermal generation resources, the screening curve provides an algebraic way to show which type of thermal generation is the least cost alternative for each plant factor range. In combination with the Missouri River system generation-duration curve, the screening curve produces a composite unit capacity value. The following is an explanation of the steps required to compute the capacity composite unit values.

The screening curve assumes a linear function defined by the following equation:

$$AC = CV + (EV * 0.0876 * PF)$$

where:

AC = annual thermal generating plant total cost ($/kW-year)
CV = thermal generating plant capacity cost ($/kW-year)
EV = thermal generating plant operating cost ($/MWh)

Capacity unit values for coal-fired steam, gas-fired combined cycle and combustion turbine plants were computed using procedures developed by FERC. Table 2 shows the average capacity and energy costs for states that lie in the Midwest Reliability Organization – West (MROW) of EIA's Electricity Market Module (EMM) Region.

Table 2. Average Capacity and Energy Costs for MROW EMM

	Coal-fired Steam (CO)	Combined Cycle (CC)	Combustion Turbine (CT)
Adjusted Capacity Value ($/kW-yr)	$328.78	$174.71	$92.64
Operation Costs ($/MWh)	$30.95	$38.62	$60.92

The plot for each thermal generation type was developed by computing the annual plant cost for various plant factors ranging from zero to 100 percent. As shown in the lower section of Figure 3, combustion turbine had the lowest over all capacity cost up to the breakpoint of 42%. After that combined cycle had the lowest cost from the plant factor up from 42%. Combustion turbine accounts for 1,579 MW of estimated replacement capacity and combined cycle accounts for 921 MW of estimated replacement capacity. In this comparison, coal does not become the least cost alternative for any amount of capacity.

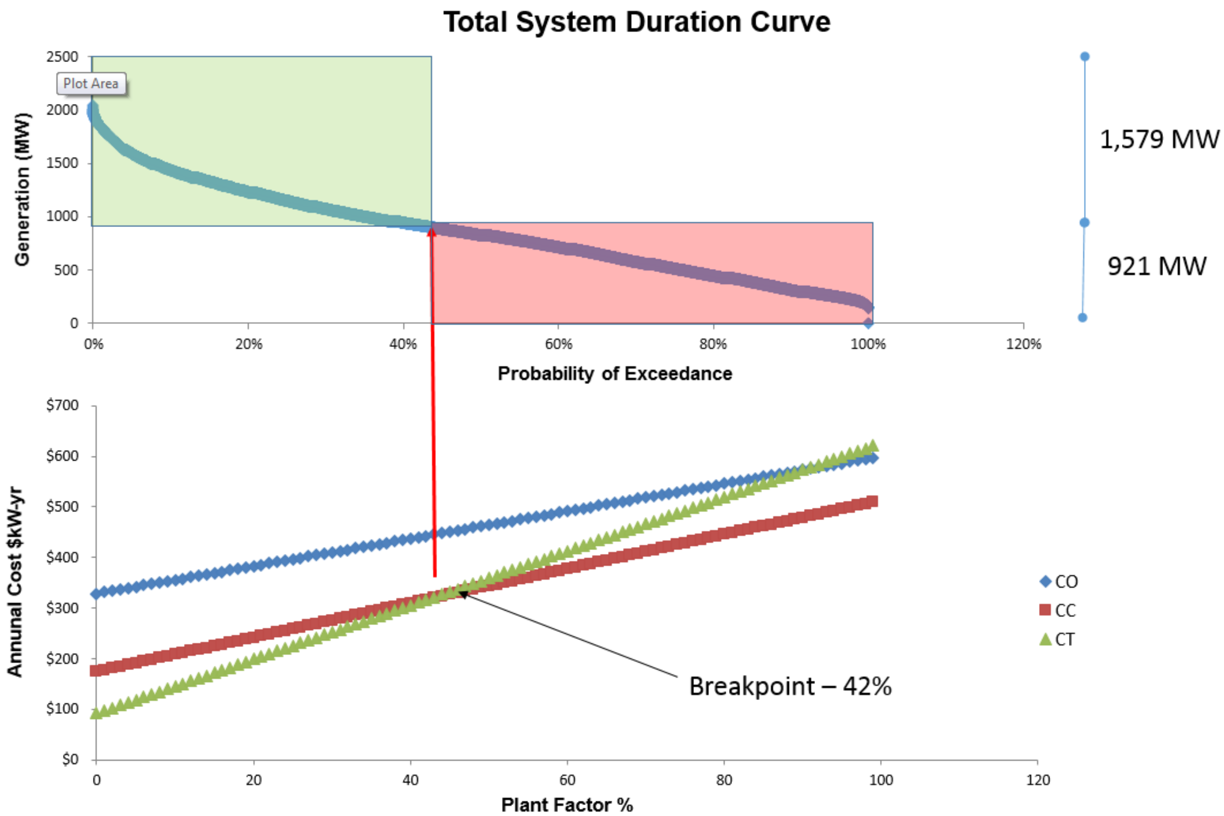


Figure 3. Total System Duration Curve and Regional Screening Curve

The following algorithm is used to compute the composite unit capacity shown in the Table 3.

1. From the cost screening curve, determine the “breakpoints” (the plant factors at which the least cost plant type changes”
2. Find the points on the generation-duration curve where the percent of time generation is numerically identical to the plant factor breakpoints defined in the preceding step; these intersection points define the portion of the generation capacity (MW) that would be carried by each thermal generation plant type.
3. Calculate percent of total generating capacity for each thermal alternative using the proportions defined in Step 2.
4. Calculated the composite unit capacity value of the system as an average of each thermal alternative’s capacity cost weighted by their percent of total generating capacity defined in Step 3.

Table 3. Composite Capacity Value of Thermal Generating Plants

	Estimated Replacement Capacity (MW)	Percentage of Total Generating Capacity	Capacity Cost ($/KW-yr)	Weighted Value ($)	
Combustion Turbine	1579	63.16	$92.64	$58.51	
Combined Cycle	921	36.84	$174.71	$64.36	
Coal-fired Steam	0	0.00	$328.78	$0.00	
				$122.87	weighted average ($/kW-yr)

3.2 Regional Economic Development Methodology

The RED evaluation will use the output of the NED evaluation to determine what changes in electricity supplied and/or wholesale electricity rates to preference customers result from changes in hydropower production. If there are significant changes in the hydropower energy produced or capacity due to Management Plan alternatives, it could lead to changes in electricity supplied or electricity rates, which could affect customer's household spending or business activity.

The Regional Economic Development benefits for hydropower are based on the results of the NED analysis. Western Area Power Administration (WAPA) markets its firm power from the hydropower plant to various preferred customers who meet federally mandated criteria. In general, power is marketed to meet the customer's hourly needs. Changes to overall system operations may affect the ability for WAPA to meet these firm demands. Sales of electric power must repay all costs associated with power generation. Under the Reclamation Project Act of 1939, WAPA must establish power rates sufficient to recover operating, maintenance and purchase power expenses and repay the federal government's investment within 50 years for building these generation and transmission facilities. Rates must also be set to cover certain non-power costs Congress has assigned to power users to repay, such as irrigation costs in excess of water users' ability to repay, interest expenses on the unpaid balance of power-related principal and replacement of power facilities within the expected service life of the replacement (Western 2011). WAPA conducts annual power repayment studies to ensure power rates for each project are adequate. Data in the study include historic expenses and investments already repaid from power revenues as well as projections for future years. Also listed is estimated annual repayment of generation and transmission investment costs throughout the repayment period of the project. More specifically, the studies detail year-by-year revenues and expenses, estimated amounts of investment and interest to be paid each year and the total amount of investment remaining to be repaid. Historical data is gathered primarily from accounting records through the last fiscal year. In addition to WAPA marketing and billing records, generation, hydrology and project data, historical and projected figures are provided by the Bureau of Reclamation, the USACE and the International Boundary and Water Commission. Since the amount of energy generated is based on the current hydrology of the system, accurate annual water supply forecasting is important in establishing the proper rate value.

As cooperatives, municipalities, and other preference customers receive their allocation from WAPA, the cooperative and other customers benefit from the relatively low cost source of hydropower energy, providing rates lower than other for profit electric utilities. If the rates for repayment that WAPA charges its preferred customers need to be increased to cover an increase in costs, these low cost benefits for preferred customers would decrease and would account for the RED impact. The USACE worked with WAPA to obtain reasonable estimates of the financial impact of each alternative, which would in turn affect rates.

The pricing used in this estimate was based on actual October 2015-June 2016 average SPP LMP pricing at Corps generators in the SPP footprint for on and off peak periods.

3.3 Other Social Effects Methodology

An environmental benefit associated with hydropower generation is avoided air emissions. In general, electricity generated from a hydropower resource is considered a low emission-producing resource when compared to thermal alternatives because no fuels are actually burned. Without the generation of electricity from hydropower sources, power would likely come from a fossil fuel source, such as a coal-fired or natural gas power plant. Therefore, a reduction in hydropower generation could result in an increase in air emissions due to a greater reliance on fossil fuel power generation in meeting system demand. Since different regions have different electricity-generating resource mixes, the avoided emissions factor is dependent on the region and available alternative sources of electric generation. This factor may also be seasonally or even hourly dependent as different mixes of electricity-generating resources are required to meet demand.

The primary inputs for this analysis would be those from the HBC model, described in detail in the NED Hydropower evaluation. This model will produce monthly and annual average energy generation for each alternative. Electricity generation under the NED Hydropower evaluation will be multiplied by a regional emission rate to compute the change in air emissions.

The change in benefits of a particular alternative is based on the difference in electricity generation when compared to existing conditions. For example, a positive difference from existing conditions implies a gain in annual generation, while a negative difference implies a loss in average annual electricity generation. The decreases in hydropower generation are assumed to be met with alternative sources of energy within the region and are multiplied by the avoided emission rates discussed above to quantify the change in emissions.

Emissions (e.g., SOx, NOx, CO_2, etc.) from hydropower generation are generally considered negligible since no fuels are actually burned. Therefore a reduction in hydropower generation may result in an increase in air emissions due to a greater reliance on fossil fuel power generation in meeting the system demand. The value of this benefit is a function of the emissions for the fossil fuel that would be used to replace the lost hydropower. In general, natural gas plants would be used to replace peaking energy while coal fired plants would be used to replace baseload plants.

The factors used to calculate the increased or decreased emissions depend on what mix of resources would replace the hydropower production. Since different regions have different generating resource mixes, this factor is regionally dependent. The Environmental Protection Agency's eGRID is a comprehensive database of environmental attributes of electric power systems, incorporating data from several federal agencies. One field of data stored in the eGRID database is emission rates for 26 eGRID subregions. These regions are contained within a single North American Electric Reliability Corporation (NERC) region with similar emissions and generating resource mixes. Emission rates from the eGRID database are defined as pounds per MWh for three greenhouse gases: carbon dioxide, methane, and nitrous oxide. These can be further divided into baseload and non-baseload generating resources. Since hydropower is used to replace the generating resources on the margin in this region, this study uses the non-baseload emission rates. The appropriate subregion for this study is the MRO West (Midwest Reliability Organization West), where the most recent database (2012) emissions factors are 1,965.21 lbs/MWh for carbon dioxide, 0.0526 lbs/MWh or methane, and 0.03272 lbs/MWh for nitrous oxide.

One way to value these increases and decreases in emissions is using the EPA's social cost of carbon value. In order to try to estimate a monetary cost to emissions, the EPA developed an estimated cost index for the social cost of carbon. "The purpose of the social cost of carbon (SCC) estimates…is to allow agencies to incorporate the social benefits of reducing carbon emission into cost-benefit analyses of regulatory actions that impact cumulative global emissions. The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emission in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increase flood risk, and the value of ecosystem services due to climate change" (https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf)

3.4 Environmental Quality Methodology

This account was not evaluated for hydropower.

3.5 Geographic Areas

There are six dams on the upper Missouri River which are operated for hydropower and provide power generation for the Western plains region. These dams are Fort Peck, Garrison, Oahe, Big Bend, Fort Randall, and Gavins Point.

4.0 National Economic Development Evaluation Results

The NED analysis for hydropower focused on the changes in generation (replacement energy) and dependable capacity as a result of the changing physical conditions along the Missouri River. The impacts to hydropower are the average annual change in the generation and dependable capacity value over the period of record. Table 4 shows the overall NED impact of each alternative on hydropower in the Missouri River system. Alternative 2 has the largest change from the no action alternative, resulting in an average annual loss of $5.4 million to hydropower, including impacts on both generation and dependable capacity. Total average annual impacts range from -$256,000 (0.05%) under Alternative 3 to $5,426,000 (1.03%) under Alternative 2.

4.1 Alternative 1 – No Action

Under the no-action alternative, the Missouri River Recovery Program would continue to be implemented as it is currently. This includes management actions that are in compliance with the BiOp. Management actions should not have an impact on hydropower as they are focused on areas below Gavins Point Dam. System operations under Alternative 1 would be the same as the current operations.

Table 4. Estimated National Economic Development Costs of MRRMP-EIS Alternatives to Hydropower

NED Measure	Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6
Average Annual Generation (MWH)	8,815,900	8,754,220	8,819,979	8,757,684	8,796,163	8,793,062
Average Annual Generation Value	$264,285,000	$261,986,000	$264,291,000	$262,424,000	$263,096,000	$263,572,000
Difference in Avg Annual Generation Value		-$2,299,000	$6,000	-$1,862,000	-$1,189,000	-$714,000
Average Annual Dependable Capacity Value - Summer	$261,422,000	$258,967,000	$261,400,000	$259,601,000	$261,041,000	$260,121,000
Difference in Avg Annual Dependable Capacity Value - Summer		-$2,455,000	-$22,000	-$1,821,000	-$381,000	-$1,301,000
Average Annual Dependable Capacity Value - Winter	$238,536,000	$235,514,000	$239,872,000	$237,159,000	$238,003,000	$237,569,000
Difference in Avg Annual Dependable Capacity Value - Winter		-$3,023,000	$1,336,000	-$1,377,000	-$533,000	-$967,000
Maximum Average Annual Capacity Loss		-$3,127,000	-$262,000	-$2,182,000	-$595,000	-$1,379,000
Total Average Annual Value	$525,707,000	$520,953,000	$525,691,000	$522,024,000	$524,137,000	$523,692,000
Change from Alternative 1		-$5,426,000	-$256,000	-$4,044,000	-$1,784,000	-$2,092,000
Percent Change from Alternative 1		-1.03%	-0.05%	-0.77%	-0.34%	-0.40%

*Either winter or summer dependable capacity is used to calculate the impacts depends on which season incurs the greater impact for that particular alternative at each individual dam.

The NED analysis for Alternative 1 is summarized and broken down by dam in the Table 5. Average annual generation under alternative 1 for the system is 8,815,900 MWh. The average annual value of this generation is $264,285,000. The average dependable capacity in summer is 2,127.6 MW, with a value of $261,422,000. The average dependable capacity in winter is 1,941.4, with a value of $238,536,000. The overall value of the system, including generation and dependable capacity – summer, is $525,707,000.

4.2 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

The NED Analysis for Alternative 2 is separated by plant and summarized below (Table 6). The average annual generation under this alternative is 8,754,220 MWh, a decrease of 61,680 MWh, when compared with the no action alternative. This equates to a loss in generation value of $2,299,000.

The average annual summer dependable capacity is 2,107.7 MW, a decrease of 20 MW compared to alternative 1. The average annual winter dependable capacity is 1,916.8 MW. The maximum average annual impact to dependable capacity is $3,127,000. This was determined by looking at each individual plant and determining which season had the greatest impact on that individual plant under that alternative. Each plant's maximum impact was then summed to show the maximum average annual impact on capacity. This value is also used to determine the total impact assigned to a given alternative.

The overall impact of alternative 2 as compared to alternative 1 is a loss of $5,426,000 in hydropower generation and dependable capacity. This is a loss of 1.03% of the overall system value calculated under alternative 1. 61% of the overall loss is attributable to losses in generation and dependable capacity at Oahe and Fort Randall so the majority of the impacts are being felt at those plants.

When evaluating the impacts of each of the MRRMP-EIS alternatives, it is helpful to examine the annual impacts. Figure 4 shows the annual NED impacts to hydropower generation and summer dependable capacity of Alternative 2 as compared to Alternative 1. The differences are plotted and color coded based on the type of release occurring each year. The graphic is showing that all years with full release plus low summer flows under this alternative result in years with reduced generation and capacity values. This is also true of most of the eliminated release years. The partial release years are showing a mix between years with lower value and years with higher value. However, the greatest overall negative impact is occurring in partial release years, 1965 and 2010.

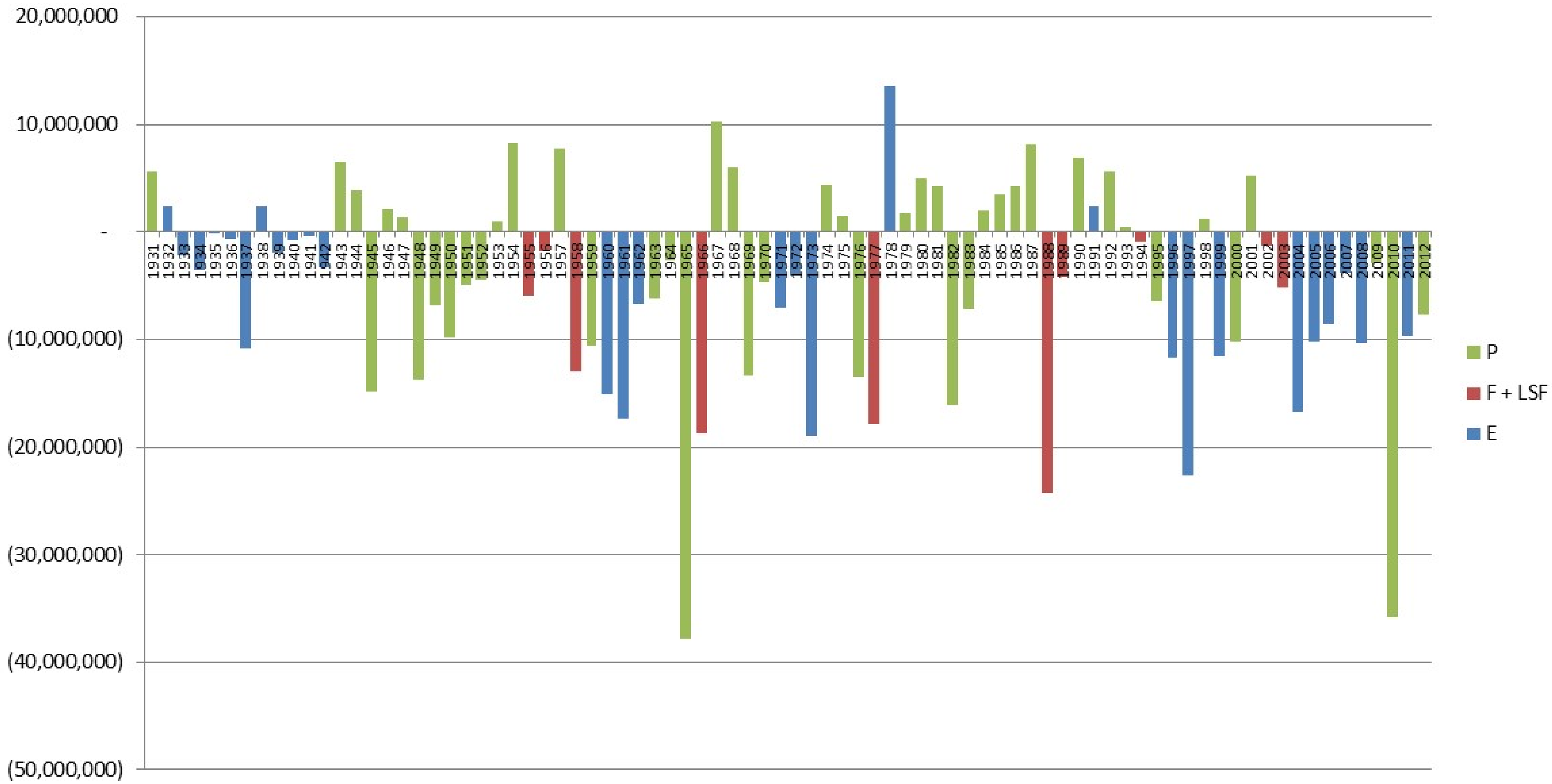
In 28 of the 82 years in the period of record, Alternative 2 would result in a higher hydropower value than Alternative 1. The average increase in these years is $4,553,000. In 54 of the years, Alternative 2 results in a lower hydropower value than Alternative 1. The average decrease in these years would be $9,464,000. The entire period of record differences between Alternative 2 and Alternative 1 range from a gain of $13,544,000 in 1978 to a loss of $37,781,000 in 1965.

Table 5. Summary of National Economic Development Analysis for Alternative 1

	Big Bend	Fort Peck	Fort Randall	Garrison	Gavins Point	Oahe	Total
Average Annual Generation (MWh)	962,581	953,836	1,687,923	2,115,030	736,308	2,360,222	**8,815,900**
Average Annual Generation Value	$33,156,000	$27,046,000	$48,484,000	$62,802,000	$19,834,000	$72,963,000	**$264,285,000**
Average Annual Dependable Capacity - Summer (MW)	459.6	190.3	338.6	442.6	114.2	582.4	**2,127.6**
Average Annual Dependable Capacity Value - Summer	$56,476,000	$23,380,000	$41,607,000	$54,377,000	$14,026,000	$71,556,000	**$261,422,000**
Average Annual Dependable Capacity - Winter (MW)	410.8	193.2	275.8	442.0	109.5	510.2	**1,941.4**
Average Annual Dependable Capacity Value - Winter	$50,471,000	$23,738,000	$33,889,000	$54,304,000	$13,451,000	$62,683,000	**$238,536,000**
Total Average Annual Value - Generation plus Capacity (Summer)	**$89,632,000**	**$50,426,000**	**$90,091,000**	**$117,179,000**	**$33,860,000**	**$144,519,000**	**$525,707,000**

Table 6. Summary of National Economic Development Analysis for Alternative 2

NED Measure	Big Bend	Fort Peck	Fort Randall	Garrison	Gavins Point	Oahe	Total
Average Annual Generation (MWh)	962,655	951,365	1,673,982	2,104,389	721,172	2,340,656	8,754,220
Generation Difference from Alt 1 (MWh)	75	-2,471	-13,941	-10,641	-15,135	-19,566	-61,680
Average Annual Generation Value	$33,123,000	$26,973,000	$48,004,000	$62,392,000	$19,375,000	$72,119,000	$261,986,000
Difference in Avg Annual Generation Value from Alt 1	-$33,000	-$73,000	-$480,000	-$410,000	-$459,000	-$844,000	-$2,299,000
Average Annual Dependable Capacity - Summer (MW)	456.2	189.7	335.6	440.5	113.1	572.6	2,107.7
Difference in Avg Annual Dependable Capacity - Summer from Alt 1 (MW)	-3.5	-0.6	-3.0	-2.1	-1.1	-9.7	-20.0
Average Annual Dependable Capacity Value - Summer	$56,048,000	$23,308,000	$41,239,000	$54,119,000	$13,892,000	$70,360,000	$258,967,000
Difference in Avg Annual Dependable Capacity Value - Summer from Alt 1	-$428,000	-$72,000	-$368,000	-$258,000	-$134,000	-$1,196,000	-$2,455,000
Average Annual Dependable Capacity - Winter (MW)	405.4	192.5	272.2	439.9	109.2	497.6	1916.8
Difference in Avg Annual Dependable Capacity - Winter from Alt 1 (MW)	-5.4	-0.7	-3.6	-2.0	-0.3	-12.6	-24.6
Average Annual Dependable Capacity Value - Winter	$49,811,000	$23,649,000	$33,448,000	$54,053,000	$13,414,000	$61,139,000	$235,514,000
Difference in Avg Annual Dependable Capacity Value - Winter from Alt 1	-$660,000	-$89,000	-$441,000	-$251,000	-$37,000	-$1,544,000	-$3,023,000
Maximum Average Annual Capacity Loss	-$660,000	-$89,000	-$441,000	-$258,000	-$134,000	-$1,544,000	-$3,127,000
Total Average Annual Change in Hydropower NED Value from Alternative 1	-$693,000	-$162,000	-$921,000	-$668,000	-$593,000	-$2,388,000	-$5,426,000
Percent Change from Alternative 1 (Generation plus Summer Capacity)	-0.77%	-0.32%	-1.02%	-0.57%	-1.75%	-1.65%	-1.03%



P – Partial Release
F + LSF – Full Release plus Low Summer Flow
E – Eliminated Release

Figure 4. Annual Difference in Value of Alternative 2 Relative to Alternative 1 for Hydropower System Value

4.3 Alternative 3 – Mechanical Construction Only

Management actions included under Alternative 3 would include those that focus on the creation of ESH through mechanical means. This alternative would have a small, negative impact on hydropower.

The NED Analysis for Alternative 3 is separated by plant and summarized below (Table 7). The average annual generation under this alternative is 8,819,979 MWh, an increase of 4,079 MWh, when compared with the no action alternative. This equates to an increase in generation value of $6,000. Under this alternative, the loses are occurring during high value times of the year, and the gains are occurring during low value times of the year, which is why the overall value of this generation is relatively low.

The average annual summer dependable capacity is 2,127.5, a decrease of 0.2 MW compared to Alternative 1. The average annual winter dependable capacity is 1952.2, an increase of 10.9. The maximum average annual impact to dependable capacity is a loss of $262,000. This was determined by looking at each individual plant and determining which season had the greatest impact on that individual plant under that alternative. Each plant's maximum impact was then summed to show the maximum average annual impact on capacity. This value is also used to determine the total impact assigned to a given alternative.

The overall impact of Alternative 3 as compared to Alternative 1 is a loss of $256,000 which includes a small gain to generation and a loss to dependable capacity in critical periods. This is a loss of 0.05% of the overall system value calculated under Alternative 1. Losses are occurring at Big Bend, Fort Randall, and Gavins Point, while small overall gains are occurring at Fort Peck, Garrision, and Oahe. Impacts to hydropower under this alternative as compared to the no action alternative are the lowest of any of the alternatives analyzed.

When evaluating the impacts of each of the MRRMP-EIS alternatives, it is helpful to examine the annual impacts. Figure 5 shows the annual NED impacts to hydropower generation and summer dependable capacity of Alternative 3 as compared to Alternative 1. The differences are not plotted and color coded based on the type of release year, since Alternative 3 does not have different types of new releases. So the graphic is simply showing the annual differences between Alternative 3 and Alternative 1.

In 38 of the 82 years in the period of record, Alternative 3 would result in a higher hydropower value than Alternative 1. The average increase in these years would be $2,361,800. In 44 of the years, Alternative 3 would result in a lower hydropower value than Alternative 1. The average decrease in these years would be $2,082,600. The entire period of record differences range from a loss of $13,188,000 in 1958 to a gain of $14,246,000 in 1987.

Table 7. Summary of National Economic Development Analysis for Alternative 3

NED Measure	Big Bend	Fort Peck	Fort Randall	Garrison	Gavins Point	Oahe	Total
Average Annual Generation (MWh)	962,319	954,310	1,687,827	2,116,808	735,805	2,362,911	8,819,979
Generation Difference from Alt 1 (MWh)	-262	473	-96	1,778	-502	2,688	4,079
Average Annual Generation Value	$33,128,000	$27,060,000	$48,449,000	$62,832,000	$19,799,000	$73,024,000	264,291,000
Difference in Avg Annual Generation Value from Alt 1	-$28,000	$14,000	-$35,000	$30,000	-$35,000	$61,000	6,000
Average Annual Dependable Capacity - Summer (MW)	459.1	190.5	338.7	443.0	114.2	582.0	2,127.5
Difference in Avg Annual Dependable Capacity - Summer from Alt 1 (MW)	-0.5	0.2	0.1	0.5	0.0	-0.4	-0.2
Average Annual Dependable Capacity Value - Summer	$56,411,000	$23,406,000	$41,615,000	$54,434,000	$14,026,000	$71,509,000	261,400,000
Difference in Avg Annual Dependable Capacity Value - Summer from Alt 1	-$65,000	$26,000	$8,000	$57,000	$0	-$47,000	-$22,000
Average Annual Dependable Capacity - Winter (MW)	416.3	193.2	274.7	442.0	109.3	516.8	1,952.2
Difference in Avg Annual Dependable Capacity - Winter from Alt 1 (MW)	5.5	0.0	-1.1	0.1	-0.2	6.6	10.9
Average Annual Dependable Capacity Value - Winter	$51,145,000	$23,736,000	$33,750,000	$54,313,000	$13,432,000	$63,496,000	239,872,000
Difference in Avg Annual Dependable Capacity Value - Winter from Alt 1	$674,000	-$2,000	-$139,000	$9,000	-$19,000	$813,000	$1,336,000
Maximum Average Annual Capacity Loss	-$65,000	-$2,000	-$139,000	$9,000	-$19,000	-$47,000	-$262,000
Total Average Annual Change in Hydropower NED Value from Alternative 1	-$93,000	$12,000	-$174,000	$39,000	-$54,000	$14,000	-$256,000
Percent Change from Alternative 1 (Generation plus Summer Capacity)	-0.10%	0.02%	-0.19%	0.03%	-0.16%	0.01%	-0.05%

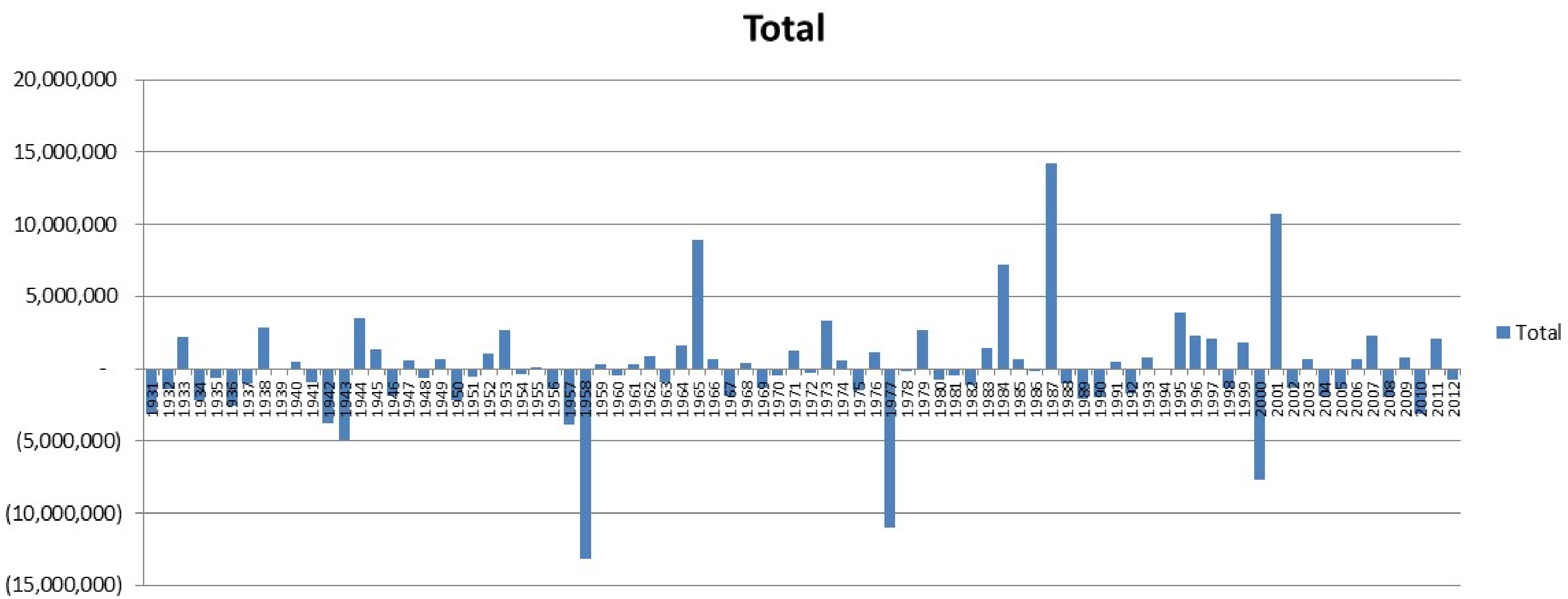


Figure 5. Annual Difference in Value Relative to Alternative 1 for Hydropower System Value

4.4 Alternative 4 – Spring ESH Creating Release

Alternative 4 focuses on developing ESH habitat through both mechanical and reservoir releases that would occur during the spring months.

The NED Analysis for Alternative 4 is separated by plant and summarized below (Table 8). The average annual generation under this alternative is 8,757,684 MWh, a decrease of 58,216 MWh, when compared with the no action alternative. This equates to a decrease in generation value of $1,862,000.

The average annual summer dependable capacity is 2,112.8, a decrease of -14.8 MW compared to Alternative 1. The average annual winter dependable capacity is 1,930.2, a decrease of 11.2 MW. The maximum average annual impact to dependable capacity is a loss of $2,182,000. This was determined by looking at each individual plant and determining which season had the greatest impact on that individual plant under that alternative. Each plant's maximum impact was then summed to show the maximum average annual impact on capacity. This value is also used to determine the total impact assigned to a given alternative.

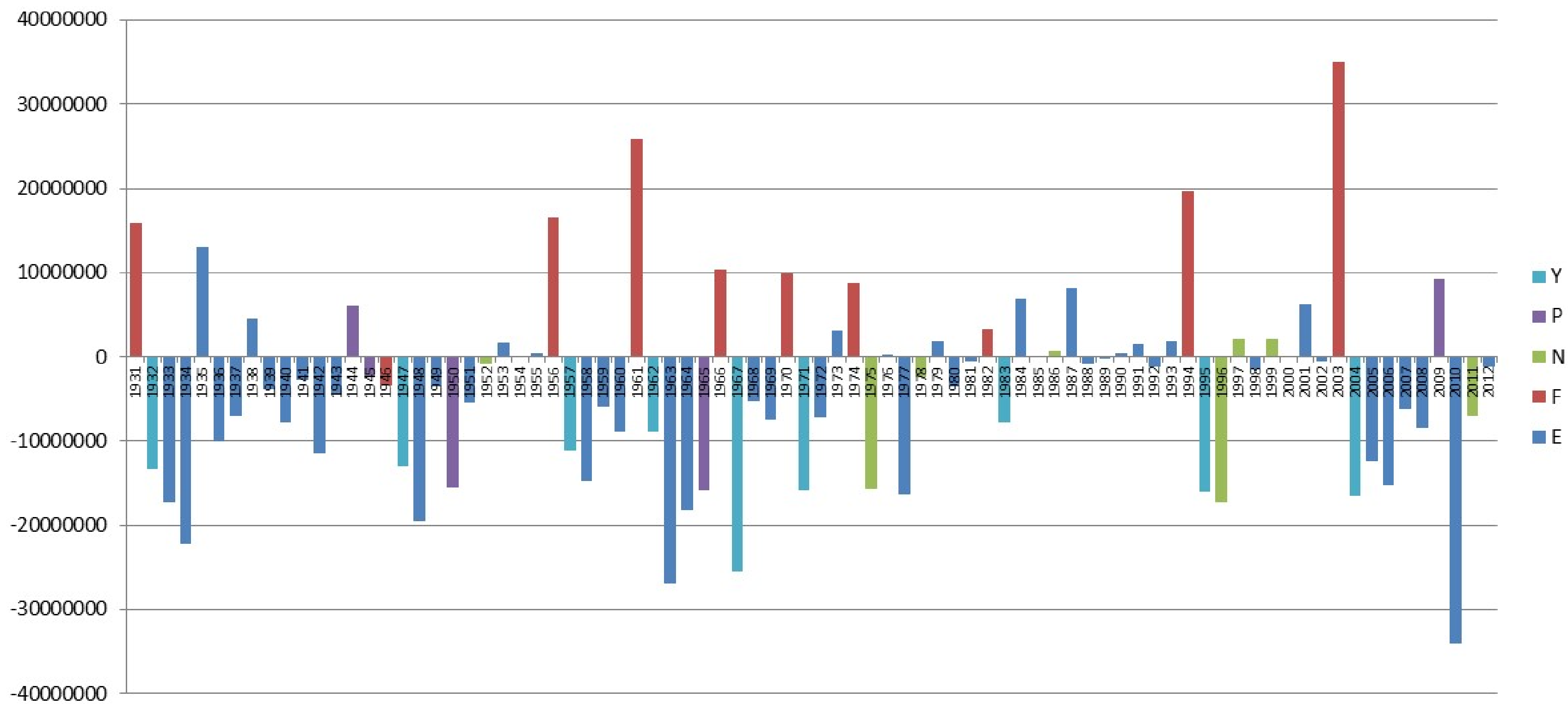
The overall impact of Alternative 4 as compared to Alternative 1 is a loss of $4,044,000 which includes losses to generation and to dependable capacity in critical periods. This is a loss of 0.77% of the overall system value calculated under Alternative 1. The majority of the loss, 76%, is occurring at Garrison and Oahe. Alternative 4 is the second most impactful alternative analyzed.

When evaluating the impacts of each of the MRRMP-EIS alternatives, it is helpful to examine the annual impacts. Figure 6 shows the annual NED impacts to hydropower generation and summer dependable capacity of Alternative 4 as compared to Alternative 1. The differences are plotted and color coded based on the type of release occurring each year. The graphic is showing that all years, except for one, are showing gains during full release years. In fact, almost all other years and all other types of releases are showing losses. The greatest overall negative impacts are occurring in eliminated release years, 1963 and 2010. The trend in Alternative 4 seems to be that while some large increases to hydropower system value occur during full release years, the years following full release year experience large losses, ultimately making generation and capacity loss under Alternative 4 the second largest, on an average annual basis.

In 30 of the 82 years in the period of record, Alternative 4 results in a higher hydropower value than Alternative 1. The average increase in these years would be $7,205,000. In 52 of the years, Alternative 4 would result in a lower hydropower value than Alternative 1. The average decrease in these types of years would be $9,998,000. The entire period of record differences between Alternative 4 and Alternative 1 range from a gain of $35,014,000 in 2003 to a loss of $34,024,000 in 2010.

Table 8. Summary of National Economic Development Analysis for Alternative 4

NED Measure	Big Bend	Fort Peck	Fort Randall	Garrison	Gavins Point	Oahe	Total
Average Annual Generation (MWh)	963,223	949,894	1,681,979	2,094,323	729,397	2,338,867	8,757,684
Generation Difference from Alt 1 (MWh)	642	(3,942)	(5,944)	(20,707)	(6,910)	(21,355)	(58,216)
Average Annual Generation Value	$33,217,000	$26,898,000	$48,320,000	$62,145,000	$19,641,000	$72,204,000	$262,424,000
Difference in Avg Annual Generation Value from Alt 1	$61,000	-$148,000	-$164,000	-$657,000	-$193,000	-$759,000	-$1,862,000
Average Annual Dependable Capacity - Summer (MW)	458.1	190.9	338.2	438.3	114.1	573.2	2,112.8
Difference in Avg Annual Dependable Capacity - Summer from Alt 1 (MW)	-1.5	0.6	-0.4	-4.3	-0.1	-9.1	-14.8
Average Annual Dependable Capacity Value - Summer	$56,292,000	$23,453,000	$41,560,000	$53,848,000	$14,015,000	$70,434,000	$259,601,000
Difference in Avg Annual Dependable Capacity Value - Summer from Alt 1	-$184,000	$73,000	-$47,000	-$529,000	-$11,000	-$1,122,000	-$1,821,000
Average Annual Dependable Capacity - Winter (MW)	411.0	191.4	274.9	438.5	109.4	505.0	1,930.2
Difference in Avg Annual Dependable Capacity - Winter from Alt 1 (MW)	0.3	-1.8	-0.9	-3.5	-0.1	-5.2	-11.2
Average Annual Dependable Capacity Value - Winter	$50,503,000	$23,520,000	$33,772,000	$53,878,000	$13,442,000	$62,043,000	$237,159,000
Difference in Avg Annual Dependable Capacity Value - Winter from Alt 1	$32,000	-$218,000	-$117,000	-$426,000	-$9,000	-$640,000	-$1,377,000
Maximum Average Annual Capacity Loss	-$184,000	-$218,000	-$117,000	-$529,000	-$11,000	-$1,122,000	-$2,182,000
Total Average Annual Change in Hydropower NED Value from Alternative 1	-$123,000	-$366,000	-$281,000	-$1,186,000	-$204,000	-$1,881,000	-$4,044,000
Percent Change from Alternative 1 (Generation plus Summer Capacity)	-0.14%	-0.73%	-0.31%	-1.01%	-0.60%	-1.30%	-0.77%



Y – Year after a full release
P – Partial Release
N – Natural Release
F – Full Release
E – Eliminated Release

Figure 6. Annual Difference in Value Relative to Alternative 1 for Hydropower

4.5 Alternative 5 – Fall ESH Creating Release

Alternative 5 would focus on developing ESH habitat through both mechanical and reservoir releases that would occur during the fall months. Alternative 5 is expected to have the second smallest impact of the alternatives analyzed on hydropower.

The NED Analysis for Alternative 5 is separated by plant and summarized below (Table 9). The average annual generation under this alternative is 8,796,163 MWh, a decrease of 19,737 MWh, when compared with the no action alternative. This equates to a decrease in generation value of $1,189,000.

The average annual summer dependable capacity is 2,124.5, a decrease of 3.1 MW compared to Alternative 1. The average annual winter dependable capacity is 1,937, a decrease of 4.3 MW. The maximum average annual impact to dependable capacity is a loss of $595,000. This was determined by looking at each individual plant and determining which season had the greatest impact on that individual plant under that alternative. Each plant's maximum impact was then summed to show the maximum average annual impact on capacity. This value is also used to determine the total impact assigned to a given alternative.

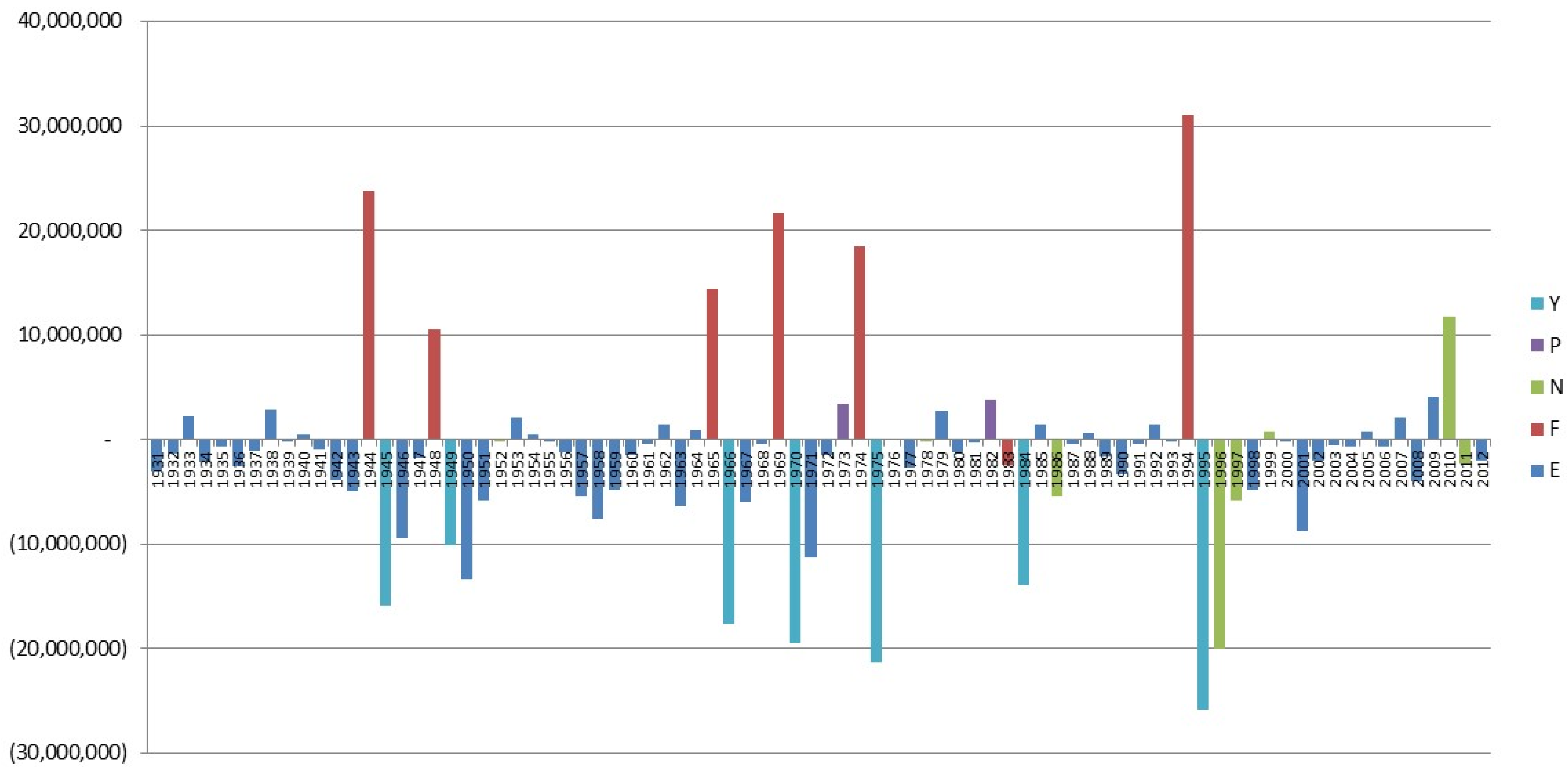
The overall impact of Alternative 5 as compared to Alternative 1 is a loss of $1,784,000 which includes losses to generation and to dependable capacity in critical periods. This is a loss of 0.34% of the overall system value calculated under Alternative 1. The majority of the loss, almost 60%, is occurring at Garrison and Oahe. Alternative 5 has the second smallest impact of the alternatives analyzed.

When evaluating the impacts of each of the MRRMP-EIS alternatives, it is helpful to examine the annual impacts. Figure 7 shows the annual NED impacts to hydropower generation and summer dependable capacity of Alternative 5 as compared to Alternative 1. The differences are plotted and color coded based on the type of release occurring each year. The graph is showing that again, years with full release are showing large gains in the overall system value. However, the year immediately following these full release years, are showing large losses. Overall, under Alternative 5 most years are showing a lower hydropower value as compared to Alternative 1, except in full release years. The trend in Alternative 5 seems to be that while some large increases to hydropower system value occur during full release years, most other years are experiencing losses.

In 25 of the 82 years in the period of record, Alternative 5 results in a higher hydropower value than Alternative 1. The average increase in these types of years would be $6,532,000. In 57 of the years, Alternative 5 results in a lower hydropower value than Alternative 1. The average decrease in these years would be $5,131,000. The entire period of record differences between Alternative 5 and Alternative 1 range from a gain of $31,104,000 in 2003 to a loss of $25,850,000 in 1995.

Table 9. Summary of National Economic Development Analysis for Alternative 5

NED Measure	Big Bend	Fort Peck	Fort Randall	Garrison	Gavins Point	Oahe	Total
Average Annual Generation (MWh)	963,317	952,357	1,680,978	2,109,128	731,887	2,358,496	8,796,163
Generation Difference from Alt 1 (MWh)	736	(1,479)	(6,945)	(5,903)	(4,420)	(1,726)	(19,737)
Average Annual Generation Value	$33,094,000	$26,992,000	$48,209,000	$62,459,000	$19,681,000	$72,662,000	$263,096,000
Difference in Avg Annual Generation Value from Alt 1	-$62,000	-$54,000	-$275,000	-$343,000	-$153,000	-$301,000	-$1,189,000
Average Annual Dependable Capacity - Summer (MW)	458.9	190.4	338.4	442.0	114.1	580.8	2,124.5
Difference in Avg Annual Dependable Capacity - Summer from Alt 1 (MW)	-0.7	0.1	-0.3	-0.6	-0.1	-1.6	-3.1
Average Annual Dependable Capacity Value - Summer	$56,390,000	$23,393,000	$41,573,000	$54,309,000	$14,018,000	$71,358,000	$261,041,000
Difference in Avg Annual Dependable Capacity Value - Summer from Alt 1	-$86,000	$13,000	-$34,000	-$68,000	-$8,000	-$198,000	-$381,000
Average Annual Dependable Capacity - Winter (MW)	410.5	192.8	275.3	440.5	109.5	508.6	1,937.0
Difference in Avg Annual Dependable Capacity - Winter from Alt 1 (MW)	-0.3	-0.4	-0.6	-1.5	0.0	-1.6	-4.3
Average Annual Dependable Capacity Value - Winter	$50,437,000	$23,687,000	$33,820,000	$54,121,000	$13,452,000	$62,487,000	$238,003,000
Difference in Avg Annual Dependable Capacity Value - Winter from Alt 1	-$34,000	-$51,000	-$69,000	-$183,000	$1,000	-$196,000	-$533,000
Maximum Average Annual Capacity Loss	-$86,000	-$51,000	-$69,000	-$183,000	-$8,000	-$198,000	-$595,000
Total Average Annual Change in Hydropower NED Value from Alternative 1	-$148,000	-$105,000	-$344,000	-$526,000	-$161,000	-$499,000	-$1,784,000
Percent Change from Alternative 1 (Generation plus Summer Capacity)	-0.17%	-0.21%	-0.38%	-0.45%	-0.48%	-0.35%	-0.34%



Y – Year after a full release
P – Partial Release
N – Natural Release
F – Full Release
E – Eliminated Release

Figure 7. Alternative 5 Difference in Value from Alternative 1 for Hydropower

4.6 Alternative 6 – Pallid Sturgeon Spawning Cue

Alternative 6 includes actions that would develop ESH habitat through mechanical means and a spawning cue flow that would be mimicked through bi-modal pulses that would occur in March and May. Alternative 6 is expected to have the third most negative impact on hydropower of the alternatives analyzed.

The NED Analysis for Alternative 6 is separated by plant and summarized below (Table 10). The average annual generation under this alternative is 8,793,062 MWh, a decrease of 22,838 MWh, when compared with the no action alternative. This equates to a decrease in generation value of $714,000.

The average annual summer dependable capacity is 2,117.0, a decrease of 10.6 MW compared to Alternative 1. The average annual winter dependable capacity is 1,933.5, a decrease of 7.9 MW. The maximum average annual impact to dependable capacity is a loss of $1,379,000. This was determined by looking at each individual plant and determining which season had the greatest impact on that individual plant under that alternative. Each plant's maximum impact was then summed to show the maximum average annual impact on capacity. This value is also used to determine the total impact assigned to a given alternative.

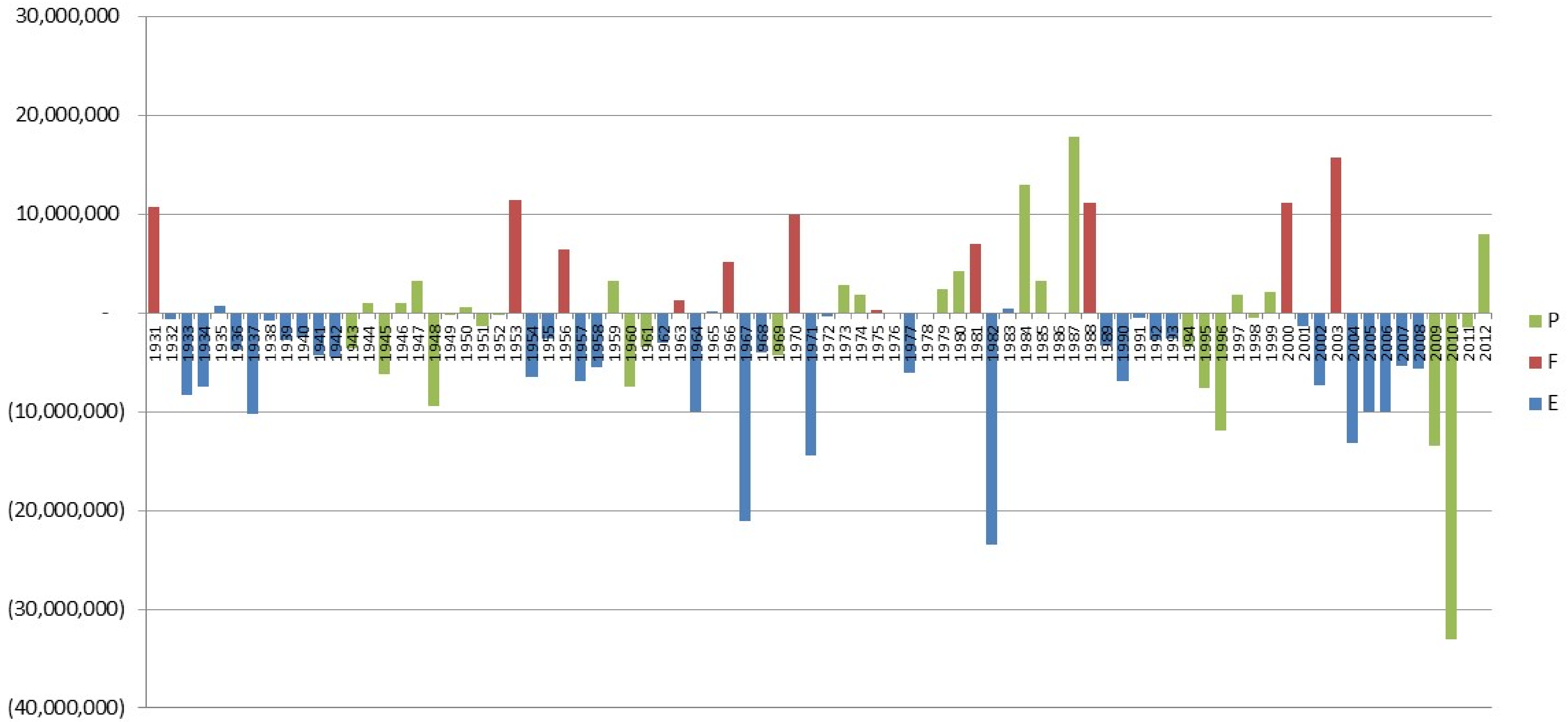
The overall impact of Alternative 6 as compared to Alternative 1 is a loss of $2,092,000 which includes losses to generation and to dependable capacity in critical periods. This is a loss of 0.4% of the overall system value calculated under Alternative 1. Over half of this loss, 56%, is occurring at Oahe. Garrison and Oahe together are accounting for over 85% of the loss. Alternative 6 has the third largest impact of the alternatives analyzed.

When evaluating the impacts of each of the MRRMP-EIS alternatives, it is helpful to examine the annual impacts. Figure 8 shows the annual NED impacts to hydropower generation and summer dependable capacity of Alternative 6 as compared to Alternative 1. The differences are plotted and color coded based on the type of release occurring each year. The graph is showing that some gains to system value are occurring in full and partial release years, but eliminated release and some partial release years are showing losses.

In 25 of the 82 years in the period of record, Alternative 5 results in a higher hydropower value than Alternative 1. The average increase in these types of years would be $6,532,000. In 57 of the years, Alternative 5 would results in a lower hydropower value than Alternative 1. The average decrease in these years would be $5,131,000. The entire period of record differences between Alternative 5 and Alternative 1 range from a gain of $17,885 in 1987 to a loss of $33,041,000 in 2010.

Table 10. Summary of National Economic Development Analysis for Alternative 6

NED Measure	Big Bend	Fort Peck	Fort Randall	Garrison	Gavins Point	Oahe	Total
Average Annual Generation (MWh)	964,060	952,249	1,688,014	2,107,858	733,065	2,347,817	8,793,062
Generation Difference from Alt 1 (MWh)	1,479	(1,588)	91	(7,172)	(3,242)	(12,406)	(22,838)
Average Annual Generation Value	$33,263,000	$26,975,000	$48,539,000	$62,510,000	$19,751,000	$72,534,000	$263,572,000
Difference in Avg Annual Generation Value from Alt 1	$107,000	-$71,000	$55,000	-$292,000	-$83,000	-$429,000	-$714,000
Average Annual Dependable Capacity - Summer (MW)	458.8	189.7	338.3	440.0	114.0	576.2	2,117.0
Difference in Avg Annual Dependable Capacity - Summer from Alt 1 (MW)	-0.8	-0.6	-0.3	-2.6	-0.1	-6.1	-10.6
Average Annual Dependable Capacity Value - Summer	$56,376,000	$23,302,000	$41,567,000	$54,064,000	$14,011,000	$70,800,000	$260,121,000
Difference in Avg Annual Dependable Capacity Value - Summer from Alt 1	-$100,000	-$78,000	-$40,000	-$313,000	-$15,000	-$756,000	-$1,301,000
Average Annual Dependable Capacity - Winter (MW)	410.9	192.1	275.6	439.9	109.2	505.8	1,933.5
Difference in Avg Annual Dependable Capacity - Winter from Alt 1 (MW)	0.2	-1.1	-0.2	-2.1	-0.3	-4.3	-7.9
Average Annual Dependable Capacity Value - Winter	$50,491,000	$23,601,000	$33,864,000	$54,044,000	$13,419,000	$62,150,000	$237,569,000
Difference in Avg Annual Dependable Capacity Value - Winter from Alt 1	$20,000	-$137,000	-$25,000	-$260,000	-$32,000	-$533,000	-$967,000
Maximum Average Annual Capacity Loss	-$100,000	-$137,000	-$40,000	-$313,000	-$32,000	-$756,000	-$1,379,000
Total Average Annual Change in Hydropower NED Value from Alternative 1	$7,000	-$208,000	$15,000	-$605,000	-$115,000	-$1,185,000	-$2,092,000
Percent Change from Alternative 1 (Generation plus Summer Capacity)	0.01%	-0.41%	0.02%	-0.52%	-0.34%	-0.82%	-0.40%



P – Partial Release
F + LSF – Full Release plus Low Summer Flow
E – Eliminated Release

Figure 8. Alternative 6 Difference from Alternative 1 for Hydropower

5.0 Regional Economic Development Evaluation Results

Regional Economic Development impacts are based on the results of the NED analysis. WAPA markets its firm power from hydropower to various preferred customers that meet federally mandated criteria. Changes to the operations of the system will impact WAPA's ability to meet the demand for electricity, possibly leading to the need to purchase power.

Sales of electric power must repay all costs associated with power generation. WAPA provided their hourly preference customer and pumping load in the SPP footprint and their deliveries external to SPP in FY2016 and compared the generation data from the HBC model for 2012, which was identified as a typical generation year in the existing condition. Then net hourly generation for every day of the year was obtained by subtracting the load or demand from the generation. The prices used in these comparisons are different than those used for the NED analysis and were based on actual Oct/2015-June/2016 average SPP LMP pricing at Corps of Engineers generators in the SPP footprint for on/off peak periods.

5.1 Summary of Regional Economic Development Results

A summary of the RED impacts for each alternative are summarized in Table 11.

Table 11. Environmental Consequences Relative to Hydropower: Regional Economic Development

Alternative	Financial Impact to WAPA in 2012
Alternative 2	($3,783,700)
Alternative 3	($690,500)
Alternative 4	($837,100)
Alternative 5	($3,354,200)
Alternative 6	$5,461,000

5.2 Alternative 1 – No Action

Under Alternative 1, the generation for 2012 would provide a surplus of 1,386,600 MWh valued at $27,832,200 beyond the typical load requirements.

In order to add some additional perspective to the no action alternative, the generation for 2008 was also analyzed, since it was a drought year in the basin. In 2008, under the no action condition, generation for the system was shown to be a deficit of 3,039,900 MWh, meaning that power purchases would need to be made in order to meet the demand on the system. The value of the power that would have to be purchased to meet the system demand is estimated at $53,534,600 for 2008.

5.3 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

Under Alternative 2, in 2012, WAPA would incur a financial loss of $3,783,700. 2012 was used because it is defined as a normal generation year and thus could be representative of the typical annual impact expected due to the implementation of these alternatives. WAPA provided their hourly preference customer and pumping load in the SPP footprint and their deliveries external to SPP in FY2016 and compared the generation data from the hydropower benefits model for 2012, identified as a normal generation year. Then they obtained net hourly generation for every day of that year by subtracting the load or demand from the generation to see where the generation fell short and they would have to purchase energy to meet the demand and where there was extra generation that could be sold onto the market. So these values and numbers discussed represent the difference between the net generation under Alternative 1 and Alternative 2. Then an on-peak and off-peak energy price was applied to indicate the financial impact to WAPA of each alternative.

Therefore, Alternative 2 would increase power purchases or reduce surplus sales by almost $3.8 million in a typical generation year. Of the 8,784 hours examined, 52% of the hours resulted in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $6,500. The largest single hour purchase over the year was $22,800. 48% of the hours provided surplus power and with that the ability to sell the power on the market at an average of $5,200.

Another year examined was 2008, considered a lower than typical generation year/a drought year. When comparing the impact of Alternative 2 to Alternative 1, the financial loss was $2,569,600, meaning Alternative 2 would increase power purchases or reduce surplus sales by about $2.4 million in this drought year. Of the 8,784 hours examined, 54% of the hours resulted in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $4,100. The largest single hour purchase over the year was $15,600. 46% of the hours provided surplus power and with that the ability to sell the power on the market at an average of $3,700. These results suggest that in a year already impacting generation due to drought, the financial impact to WAPA may actually be less than in a typical year under Alternative 2, most likely because overall generation is already reduced.

5.4 Alternative 3– Mechanical Construction Only

Under Alternative 3, in 2012, WAPA would incur a financial loss of $690,500. 2012 was used because it is defined as a normal generation year and thus could be representative of the typical annual impact expected due to the implementation of these alternatives.

Therefore, Alternative 3 would increase power purchases or reducing surplus sales by almost $700,000 in this typical generation year. Of the 8,784 hours examined, 49% of the hours resulted in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $3,000. The largest single hour purchase over the year was $17,400. 51% of the hours provided surplus power and with that the ability to sell the power on the market at an average of $2,700.

Another year examined was 2008, considered a lower than typical generation year/a drought year. When comparing the impact of Alternative 3 to Alternative 1, the financial loss was $327,400, meaning Alternative 3 would increase power purchases or reduce surplus sales in this drought year. Of the 8,784 hours examined, 51% of the hours resulted in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $3,400. The largest single hour purchase over the year was $16,700. 49% of the hours provided surplus power and with that the ability to sell the power on the market at an average of $3,400. These results suggest that in a year already impacting generation due to drought, the financial impact to WAPA may actually be less than in a typical year under Alternative 3, most likely because overall generation is already reduced.

5.5 Alternative 4 – Spring ESH Creating Release

Under Alternative 4, in 2012, WAPA would incur a financial loss of $837,100. 2012 was used because it is defined as a normal generation year and thus could be representative of the typical annual impact expected due to the implementation of these alternatives.

Therefore, Alternative 4 would increase power purchases or reduce surplus sales by about $837,100 in this typical generation year. Of the 8,784 hours examined, 51% of the hours would results in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $2,800. The largest single hour purchase over the year was $17,900. 49% of the hours provided surplus power and with that the ability to sell the power on the market at an average of $2,700.

Another year examined was 2008, considered a lower than typical generation year/a drought year. When comparing the impact of Alternative 4 to Alternative 1, the financial loss was $3,448,400, meaning Alternative 4 would increase power purchases or reduce surplus sales in this drought year. Of the 8,784 hours examined, 56% of the hours resulted in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $2,500. The largest single hour purchase over the year was $17,400. 44% of the hours provided surplus power and with that the ability to sell the power on the market at an average of $2,200. These results suggest that in a year already impacting generation due to drought, the financial impact to WAPA may be larger than in a typical year under Alternative 4.

5.6 Alternative 5 – Fall ESH Creating Release

Under Alternative 5, in 2012, WAPA would incur a financial loss of $3,354,200. 2012 was used because it is defined as a normal generation year and thus could be representative of the typical annual impact expected due to the implementation of these alternatives. This result is somewhat unexpected given that the NED impact of Alternative 5 is the second least impactful, whereas in the RED analysis, it is the second largest loss. However, the NED is averaged over the entire period of record. For the purposes of this analysis, 2012 in the existing condition was intended to be representative of a normal year. When looking at the individual year NED results for 2012, the RED results are following the same pattern.

Therefore, Alternative 5 would increase power purchases or reduce surplus sales by about $3,354,200 in this typical generation year. Of the 8,784 hours examined, 51% of the hours would result in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $4,800. The largest single hour purchase over the year was $17,600. 49% of the hours provided surplus power and with that the ability to sell the power on the market at an average of $3,600.

Another year examined was 2008, considered a lower than typical generation year/a drought year. When comparing the impact of Alternative 5 to Alternative 1, the financial loss was $1,183,400, meaning Alternative 5 would increase power purchases or reduce surplus sales in this drought year. Of the 8,784 hours examined, 48% of the hours resulted in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $4,500. The largest single hour purchase over the year was $18,500. 52% of the hours provided surplus power and with that the ability to sell the power on the market at an average of $3,700. These results suggest that in a year already impacting generation due to drought, the financial impact to WAPA may actually be less than in a typical year under Alternative 5, most likely because overall generation is already reduced.

5.7 Alternative 6 – Pallid Sturgeon Spawning Cue

Under Alternative 6, in 2012, WAPA would incur a financial gain of $5,461,000. 2012 was used because it is defined as a normal generation year, at least in the existing condition, and thus could be representative of the typical annual impact expected due to the implementation of these alternatives. This result for Alternative 6 is somewhat unexpected given that the NED impact of Alternative 5 is a loss, whereas in the RED analysis, there is a financial gain. However, the NED result is averaged over the entire period of record. For the purposes of this analysis, 2012 in the existing condition was intended to be representative of a normal year. When looking at the individual year NED results for 2012, the RED results are following the same pattern.

Therefore, Alternative 6 would reduce power purchases or increase surplus sales by about $5,461,000 in this typical generation year. Of the 8,784 hours examined, 45% of the hours would result in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $4,600. The largest single hour purchase over the year was $19,100. 55% of the hours provided surplus power and with that the ability to sell the power on the market at an average of $6,000.

Another year examined was 2008, considered a lower than typical generation year/a drought year. When comparing the impact of Alternative 6 to Alternative 1, the financial loss was $2,297,400, meaning Alternative 6 would increase power purchases or reduce surplus sales in this drought year. Of the 8,784 hours examined, 57% of the hours resulted in an inability to meet the load, meaning power would need to be purchased. The average cost of the purchase would be $3,400. The largest single hour purchase over the year was $14,100. 43% of the hours provided surplus power and with that the ability to sell the power on the market at an average of $3,400. These results suggest that in a year already impacting generation due to drought, the financial impact to WAPA may be larger than in a typical year under Alternative 6.

6.0 Other Social Effects Results

The OSE analysis for hydropower relied on the results of the NED analysis to show how changes to hydropower generation could impact air emissions. Reductions in hydropower generation would need to be made up by increasing other sources of power generation, likely to be a reliable fossil fuel source that produces greenhouse gases. As discussed in the methodology section, the EPA eGrid database was used to determine the appropriate region and emissions factors for this study. The emissions factors are 1,965.21 lbs/MWh for carbon dioxide, 0.0526 lbs/MWh for methane, and 0.03272 lbs/MWh for nitrous oxide.

6.1 Summary of Other Social Effects Impacts

A summary of OSE Impacts for the MRRMP-EIS alternatives is summarized in Table 12.

Table 12. Environmental Consequences Relative to Hydropower: Other Social Effects

Change in Emissions	Carbon Dioxide (lbs)	Methane (lbs)	Nitrous Oxide (lbs)	Carbon Dioxide Equivalent (kt)
Average Annual Increase in Emissions under Alternative 2	121,214,153	3,244	2,018	55,292
Average Annual Decrease in Emissions under Alternative 3	8,016,092	215	133	3,656
Average Annual Increase in Emissions under Alternative 4	114,406,665	3,062	1,905	52,186
Average Annual Increase in Emissions under Alternative 5	38,787,350	1,038	646	17,693
Average Annual Increase in Emissions under Alternative 6	44,881,466	1,201	747	20,473

6.2 Alternative 1 – No Action

Changes in hydropower operations have the potential to cause other types of effects than simply impacting generation and capacity values. An environmental benefit associated with hydropower is a reduction in greenhouse gases as compared to thermal power generation. If the Missouri River hydropower system generation was actually being produced by thermal power sources, it would increase annual emissions by 17,325,094,839 lbs of carbon dioxide, 463,716 lbs of methane, and 288,456 lbs of nitrous oxide. The social cost of carbon discussed in the methodology section is intended to estimate the social costs of increased and decreased emissions. The social cost of carbon for 2016 is $38 per metric tons of CO2 (using a 3% discount rate). The social cost of the carbon emissions if the power currently generated by the hydropower system had to be generated by a thermal power source would be $298,624,140. That the system does not produce these emissions could be considered the baseline level of benefit and impact for the Other Social Effects accounts.

6.3 Alternative 2 – USFWS 2003 Biological Opinion Projected Actions

Under alternative 2, average annual emissions relative to Alternative 1 would likely go up, as the lost power generation would likely be made up by thermal power sources to meet the demand for power. Table 13 shows the OSE and emissions impact of replacing this lost generation.

Table 13. Environmental Consequences Relative to Hydropower: Average Annual Change in Emissions

Alternative 2	
Average Annual Increase in Carbon Dioxide (lbs)	121,214,153
Average Annual I Increase in Methane (lbs)	3,244
Average Annual Increase in Nitrous Oxide (lbs)	2,018
Average Annual Increase in Carbon Dioxide Equivalent (metric tons)	55,292
Social Cost of Carbon	$2,089,000

Under Alternative 2, emissions would increase by 121,214,153 lbs of carbon dioxide, 3,244 lbs of methane, and 2,018 lbs of nitrous oxide annually. The social cost of carbon discussed in the OSE methodology section is intended to estimate the social costs of increased and decreased emissions. The social cost of carbon for 2016 is $38 per metric ton of CO2 (using a 3% discount rate). The social cost of increased carbon emissions under Alternative 2 would be $2,089,000.

6.4 Alternative 3 – Mechanical Construction Only

Under Alternative 3, average annual emissions relative to Alternative 1 would likely go down, as there is a small increase in average annual generation. Table 14 shows the OSE and emissions impact of replacing this lost generation.

Table 14. Environmental Consequences Relative to Hydropower: Average Annual Change in Emissions

Alternative 3	
Average Annual Increase in Carbon Dioxide (lbs)	8,016,092
Average Annual I Increase in Methane (lbs)	215
Average Annual Increase in Nitrous Oxide (lbs)	133
Average Annual Increase in Carbon Dioxide Equivalent (metric tons)	3,656
Social Cost of Carbon	$138,170

Under Alternative 3, emissions would decrease by 8,016,092 lbs of carbon dioxide, 215 lbs of methane, and 133 lbs of nitrous oxide annually. The social cost of carbon discussed in the OSE methodology section is intended to estimate the social costs of increased and decreased emissions. The social cost of carbon for 2016 is $38 per metric ton of CO2 (using a 3% discount rate). The social gain of decreased carbon emissions under Alternative 3 would be $138,170.

6.5 Alternative 4 – Spring ESH Creating Release

Under Alternative 4, average annual emissions relative to Alternative 1 would likely go up, as the lost power generation would likely be made up by thermal power sources. Table 15 shows the OSE and emissions impact of replacing this lost generation.

Table 15. Environmental Consequences Relative to Hydropower: Average Annual Increase in Emissions

Alternative 4	
Average Annual Increase in Carbon Dioxide (lbs)	114,406,665
Average Annual I Increase in Methane (lbs)	3,062
Average Annual Increase in Nitrous Oxide (lbs)	1,905
Average Annual Increase in Carbon Dioxide Equivalent (metric tons)	52,186
Social Cost of Carbon	$1,971,974

Under Alternative 4, emissions would increase by 114,406,665 lbs of carbon dioxide, 3,062 lbs of methane, and 1,905 lbs of nitrous oxide annually. The social cost of carbon discussed in the OSE methodology section is intended to estimate the social costs of increased and decreased emissions. The social cost of carbon for 2016 is $38 per metric ton of CO2 (using a 3% discount rate). The social cost of increased carbon emissions under Alternative 4 would be $1,971,974.

6.6 Alternative 5 – Fall ESH Creating Release

Under Alternative 5, average annual emissions relative to Alternative 1 would likely go up, as the lost power generation would likely be made up by thermal power sources. Table 16 shows the OSE and emissions impact of replacing this lost generation.

Table 16. Environmental Consequences Relative to Hydropower: Average Annual Change in Emissions

Alternative 5	
Average Annual Increase in Carbon Dioxide (lbs)	38,787,350
Average Annual I Increase in Methane (lbs)	1,038
Average Annual Increase in Nitrous Oxide (lbs)	646
Average Annual Increase in Carbon Dioxide Equivalent (metric tons)	17,693
Social Cost of Carbon	$668,559

Under Alternative 5, emissions would increase by 38,787,350 lbs of carbon dioxide, 1,038 lbs of methane, and 646 lbs of nitrous oxide annually. The social cost of carbon discussed in the OSE methodology section is intended to estimate the social costs of increased and decreased emissions. The social cost of carbon for 2016 is $38 per metric ton of CO2 (using a 3% discount rate). The social cost of increased carbon emissions under Alternative 5 would be $668,559.

6.7 Alternative 6 – Pallid Sturgeon Spawning Cue

Under Alternative 6, average annual emissions relative to Alternative 1 would likely go up, as the lost power generation would likely be made up by thermal power sources. Table 17 shows the OSE and emissions impact of replacing this lost generation.

Table 17. Environmental Consequences Relative to Hydropower: Average Annual Change in Emissions

Alternative 6	
Average Annual Increase in Carbon Dioxide (lbs)	44,881,466
Average Annual I Increase in Methane (lbs)	1,201
Average Annual Increase in Nitrous Oxide (lbs)	747
Average Annual Increase in Carbon Dioxide Equivalent (metric tons)	20,473
Social Cost of Carbon	$773,601

Under Alternative 6, emissions would increase by 44,881,466 lbs of carbon dioxide, 1,201 lbs of methane, and 747 lbs of nitrous oxide annually. The social cost of carbon discussed in the OSE methodology section is intended to estimate the social costs of increased and decreased emissions. The social cost of carbon for 2016 is $38 per metric ton of CO_2 (using a 3% discount rate). The social cost of increased carbon emissions under Alternative 6 would be $773,601.

7.0 Environmental Quality Results

This account was not evaluated for hydropower.

8.0 References

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