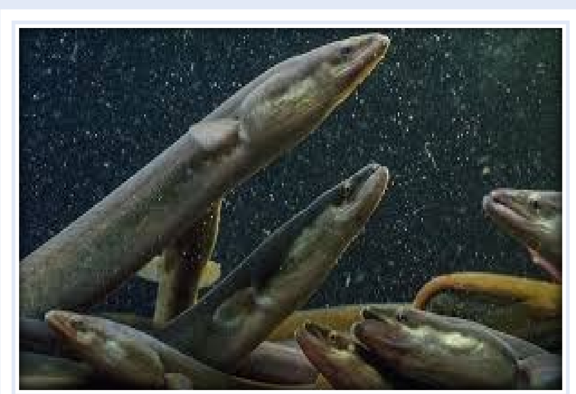
Claiborne and Millers Ferry Locks and Dams Fish Passage Study

Appendix F: Impacts to Hydropower

May 2023



US Army Corps of Engineers

The Nature Conservancy

Claiborne Lock and Dam and Millers Ferry Lock and Dam

HYDROELECTRIC DESIGN CENTER

Claiborne Lock and Dam and Millers Ferry Lock and Dam

Fish Passage Ecosystem Restoration Study

Impacts to Hydropower

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U.S. Army Corps of Engineers

October 2022

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1 Introduction

This report, prepared by the Hydropower Analysis Center (HAC) for the USACE Mobile District, presents an economic analysis of hydropower impacts resulting from potential changes in water flows at Alabama-Coosa-Tallapoosa (ACT) river system dams made to accommodate fish passage. Energy and capacity values ("benefits") associated with hydropower are estimated for a baseline condition representing current water control operations, and for alternative flow scenarios associated with the alternatives proposed in the overall fish passage study. Simulations provided by USACE Mobile District indicate that the impacts to hydropower of the proposed changes at Millers Ferry and Claiborne dams will be limited to the Millers Ferry project; Claiborne is a non-hydropower dam, and the potential changes to flows are not expected to impact hydropower output at other dams on the river system.

Millers Ferry Lock and Dam project is located on the Alabama River in the greater Alabama-Coosa-Tallapoosa river system, and includes a powerhouse consisting of three generator units with a combined rating of 90 MW. Claiborne Lock and Dam is located below the Millers Ferry project and is a non-hydropower producing dam. Multiple other federal and non-federal dams are located in the ACT basin (Figure 1); power from the federal projects in the ACT basin is marketed to customers under contract with Southeastern Power Administration (SEPA), a division of the US Department of Energy.

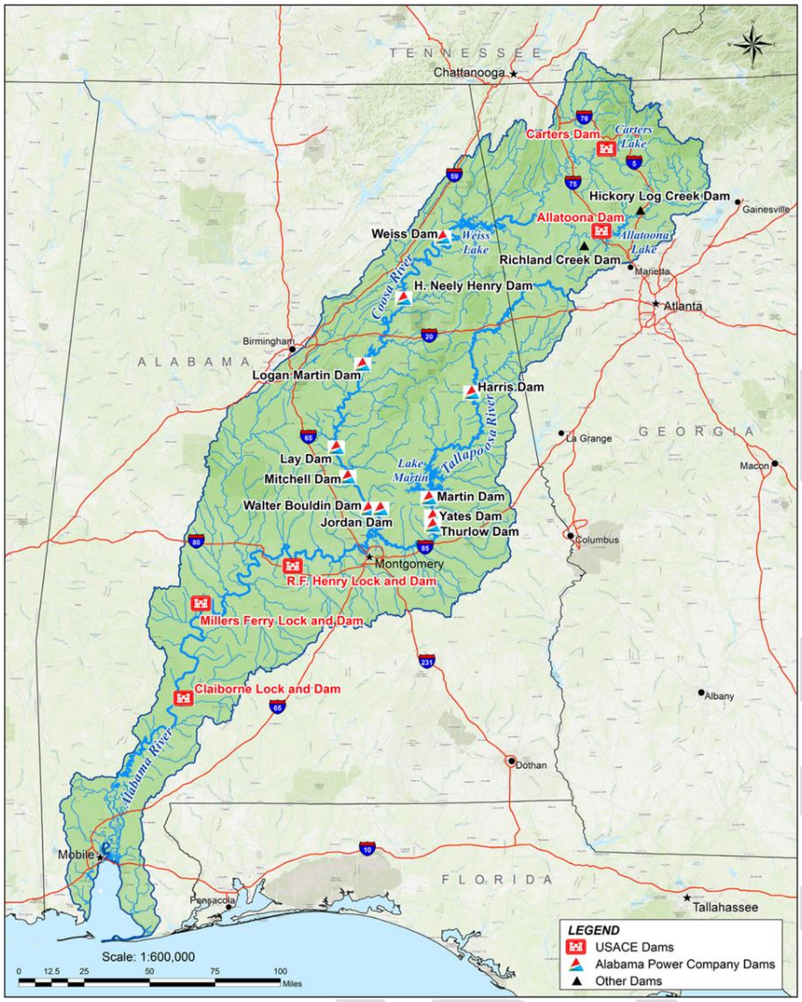

Figure 1 - ACT Basin Hydropower System

Water flows through the power plant for the period of record (1939-2011) were simulated using HEC-ResSim (ResSim), a sequential streamflow model used to estimate daily operating conditions and output under varying assumptions regarding water supply. HAC utilized the ResSim output provided by Mobile District as well as historical and forecasted market data to analyze the potential impacts to energy generation, dependable capacity, and revenues that accrue to the federal power marketing agency SEPA resulting from several alternative proposals to accommodate fish passage.

2 Study Alternatives

The results of the following alternative actions are analyzed in this report:

- **Baseline or "no action" alternative (NAA):** Operations remain unchanged from current conditions
- **Alternative 3:** Rock weirs at both Millers Ferry and Claiborne
- **Alternative 5d:** Bypass channels at both Millers Ferry and Claiborne
- **Alternative 12b:** Rock weir at Claiborne, bypass channel at Millers Ferry
- **Alternative 13b:** Bypass channel at Claiborne, rock weir at Millers Ferry

Full descriptions of the alternatives can be found in the main study report. As noted above, ResSim simulation output reflecting operations at all ACT system dams indicates that the proposed alternatives will only impact hydropower at Millers Ferry dam.

3 Study Assumptions

The following assumptions underlie HAC's analysis. Other explicit assumptions and inputs are described as they enter the analysis in the sections below.

- The hydrological period of record for ResSim output was 1939-2011. The output for the first January in the period were incomplete. Therefore, for month-level estimates, this first incomplete year was omitted from the analysis.
- Hydropower benefits were calculated over a 50-year future period.
- The analysis employs the federal discount rate of 2.5% throughout.
- All dollar figures are stated in constant FY 2023 dollars.
- Because the hydropower impacts of the proposed alternatives will be limited to Millers Ferry, most estimates and results are presented only for Millers Ferry. These estimates likewise reflect the overall hydropower impacts to the ACT system dams (by definition).

4 Hydropower Impacts

HAC's analysis covers two major values stemming from hydropower operations: those of energy generation and dependable capacity.

4.1 Energy Generation Impacts

An estimate of the impacts to hydropower generation of the proposed actions was based on simulations of operations of ACT river system dams under baseline (current conditions with no action taken) and each of the proposed alternatives. Mobile District provided simulations of daily output from the ResSim model for each of the dams in the system for a 72-year period under each of the alternatives. In these simulations, only Millers Ferry hydropower production is impacted, with generation at all other dams unchanged across all alternatives and the no-action current conditions. Table 1 below summarizes annual energy produced by the entire system and Millers Ferry under baseline conditions and each alternative. Note that the change from baseline indicated for both the system matches that for Millers Ferry. On an annual basis, generation at Millers Ferry falls roughly 8 percent from the baseline under Alternatives 5d and 12b, and roughly 13% under Alternatives 3 and 13b.

Table 1 - Simulated Annual Average Generation – System and Millers Ferry Dam

	Annual Average MWh – ACT System				
	NAA	Alt 3	Alt 5d	Alt 12b	Alt 13b
Energy	5,541,800	5,500,124	5,516,110	5,516,086	5,500,033
Change from NAA	-	(41,676)	(25,689)	(25,714)	(41,766)

Annual Average MWh – Millers Ferry

	NAA	Alt 3	Alt 5d	Alt 12b	Alt 13b
Energy	326,225	284,549	300,535	300,511	284,459
Change from NAA	-	(41,676)	(25,689)	(25,714)	(41,766)

Hydropower operations and the value of energy both vary according to hydrology, market conditions, and other factors which change materially throughout a given day, month, or year. It was thus necessary to estimate generation on an appropriately detailed level. Figure 2 summarizes average monthly generation at Millers Ferry for each alternative.

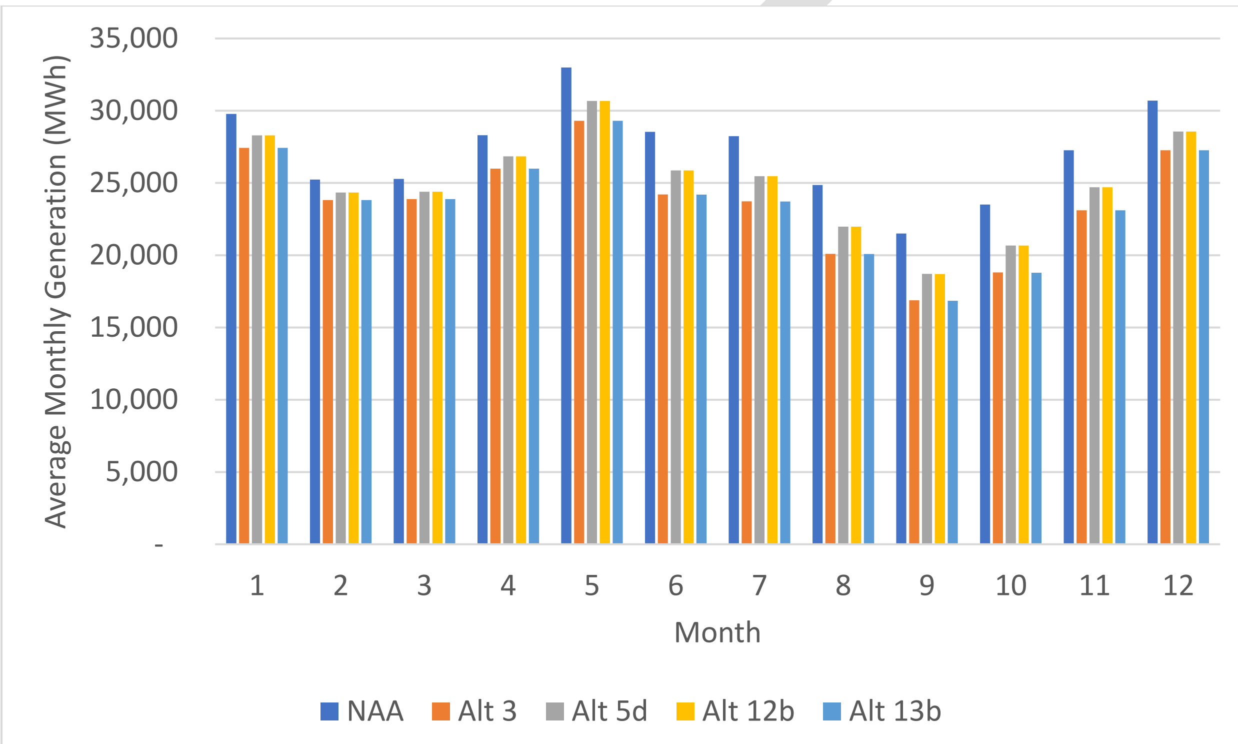

Figure 2 - Simulated Monthly Generation at Millers Ferry

Figure 2 illustrates that changes in generation would generally be more pronounced during the summer months of June to October, with shallower impacts accruing during non-summer months.

Generation is also non-uniformly distributed across the hours of the day, reflecting patterns in regional power demand and other market factors. For this study, daily simulated generation from ResSim was thus allocated to blocks of hours within each day. These generation blocks are defined primarily by energy demand peaks, with the peak period spanning 6:00am to 10:00pm on weekdays. However, because generation by USACE hydropower plants in the region is further concentrated in a subset of the highest-value weekday peak hours to fulfill power contracts, these hours were evaluated separately as "contract" on-peak hours in order not to understate their value. Table 2 presents the distribution of hours into generation blocks for contract-peak hours, non-contract peak hours, and off-peak hours for each month of the year, and for weekends. The schedule of generation blocks was provided by the Southeastern Power Administration (SEPA), an agency of the U.S. Department of Energy.

Table 2 - Daily Energy Generation Blocks

	On-Peak Hours (contract)	On-Peak Hours (non-contract)	Off-Peak Hours
Weekdays			
January	11	5	8
February	11	5	8
March	11	5	8
April	6	10	8
May	6	10	8
June	6	10	8
July	6	10	8
August	6	10	8
September	6	10	8
October	11	5	8
November	11	5	8
December	11	5	8
Weekends (All Year)			
All Months	0	0	24

As an example of how daily simulated energy production was allocated to generation blocks, Table 3 below shows the process for the Millers Ferry simulation corresponding to the hydrology of the week of March 14, 2005 under baseline conditions. Daily capability varies with hydrologic conditions; the average capability on Monday of this week was 81.1 MW and generation was 1663.7 MWh. On-peak generation for 16 hours would be 1296.8 MWh, of which 11 hours would be SEPA contract peak generation (891.6 MWh) and the remaining 5 hours of on-peak generation would be non-contract (405.3 MWh). Generation in excess of 16 hours on weekdays would be off-peak energy (366.9 MWh). All power generated on the weekend is off-peak energy.

Table 3 - Peak and Off-Peak Generation Block Allocation for Example Week

Date	Total Energy Generation (MWh)	Peak (contract) (MWh)	Peak (non-contract) (MWh)	Off-Peak (MWh)	Weekend (MWh)
Monday, March 14, 2005	1663.7	891.6	405.3	366.9	0.0
Tuesday, March 15, 2005	1597.6	916.9	416.8	263.9	0.0
Wednesday, March 16, 2005	1652.7	896.6	407.5	348.7	0.0
Thursday, March 17, 2005	1653.5	896.3	407.4	349.8	0.0
Friday, March 18, 2005	1623.3	907.5	412.5	303.3	0.0
Saturday, March 19, 2005	1643.8	0.0	0.0	0.0	1643.8
Sunday, March 20, 2005	1703.1	0.0	0.0	0.0	1703.1

This allocation process was applied to all 72 hydrologic years of ResSim simulations to transform daily output to hourly (generation block) level figures. Table 4 summarizes these sub-daily allocations by month for the baseline no-action alternative. Matching summaries for the other study alternatives can be found in the appendix to this analysis.

Table 4 - Annual Average Generation at Millers Ferry by Month and Block, No-Action Alternative

	System Annual Average MWh			
	Contract	Peak	Off Peak	Weekend
1	13,410	4,174	3,624	8,576
2	10,410	3,817	4,074	6,933
3	10,102	3,831	4,079	7,267
4	7,390	9,434	3,402	8,083
5	10,329	10,570	2,604	9,487
6	11,331	8,003	1,081	8,127
7	11,690	7,304	1,226	8,021
8	11,908	5,371	480	7,106
9	11,342	3,711	460	5,987
10	15,343	982	555	6,634
11	16,022	2,088	1,521	7,638
12	16,105	3,515	2,339	8,741

Annual average generation totals 326,225 MWh at Millers Ferry under this baseline. Table 5 summarizes the changes to annual generation under each of the alternatives considered in this study. At the annual level, impacts range from roughly -8% (Alternatives 5d and 12b) to -13% (Alternatives 3 and 13b).

Table 5 - Average Annual Generation at Millers Ferry by Alternative

	Annual Average MWh				
	NAA	Alt 3	Alt 5d	Alt 12b	Alt 13b
Energy	326,225	284,549	300,535	300,511	284,459
Change from Baseline	-	(41,676)	(25,689)	(25,714)	(41,766)

4.1.1 Energy Value

The economic value of the energy generation summarized above is based on detailed energy price forecasts for the market(s) relevant to Millers Ferry. These forecasts take annual, monthly, daily, and hourly variation in energy prices, as well as geography-specific factors that impact market supply, demand, and transmission, into account.

For this study, a forecast of hourly energy prices applicable to Millers Ferry is produced from an annual-level forecast from the US Energy Information Administration (EIA) and locational marginal pricing (LMP) data obtained for the appropriate pricing node. LMP is a computational technique that determines the hourly “shadow price” for a marginal unit (MWh) of demand. Hourly LMP data was obtained from the Midcontinent Independent System Operator (MISO) website.

The EIA publishes an Annual Energy Outlook (AEO) that includes thirty years of annual average forecasted electricity prices for market regions and sub-regions of the US organized by the three service categories of generation, transmission, and distribution. The EIA’s 2022 AEO forecast for the generation service category formed the basis of the hourly, location-specific forecast used to value Millers Ferry output. Because the AEO forecast only spans 30 years (though 2050), prices were held constant in real terms for the remaining 20 years of this study’s analytical horizon.

The EIA’s annual price forecast is used to project LMP energy prices through a relatively simple process:

- First, the historical relationship between the annual and region-wide values reported by the EIA and the hourly and location-specific LMP values is established for each generation block (e.g., peak and off-peak) of the day.
- Then these estimated relationships are applied to future forecasted values from the EIA to produce generation block and location specific forecasted LMP values.

The historical relationships between the EIA values and the LMP values are estimated by calculating the ratio of LMP value (for the hour of the year) to the annual EIA-forecasted value for the preceding three-year (2018-2021) period, then averaging these hourly ratios within each of the generation blocks described above for each month of the year. To match the hourly LMP data with the generation blocks, the data (prices) were sorted from high to low within each day, assuming that the highest LMP values are associated with the highest value block. Table 6 summarizes the resulting average ratios for each generation block and month of the year.

Table 6 - LMP/Annual Price Ratios by Generation Block and Month

Month	Contract	Peak	Off Peak	Weekend
1	0.56	0.41	0.35	0.41
2	0.68	0.46	0.37	0.38
3	0.44	0.35	0.30	0.34
4	0.56	0.38	0.31	0.37
5	0.58	0.39	0.29	0.35
6	0.55	0.38	0.28	0.38
7	0.63	0.41	0.31	0.40
8	0.65	0.42	0.32	0.41
9	0.75	0.44	0.33	0.46
10	0.64	0.46	0.37	0.47
11	0.66	0.49	0.42	0.48
12	0.56	0.42	0.37	0.42

The EIA's Annual Energy Outlook 2022 includes several scenarios - a Reference Case that serves as a baseline forecast (and which is used for the valuations in this study), and several alternate scenarios that take into account the uncertainty associated with different possible market conditions. These side cases are defined by assumptions regarding macroeconomic conditions, global oil and gas prices and supply, and renewable energy resource costs[1]. Figure 3 illustrates the AEO 2022 forecasts, and Table 7 summarizes the variability across cases, which reflects how sensitive the estimates presented next would be to uncertainty in future energy prices.

[1] Full descriptions of forecast cases are available on the EIA website, www.eia.gov/outlooks/aeo/assumptions/case_descriptions.php

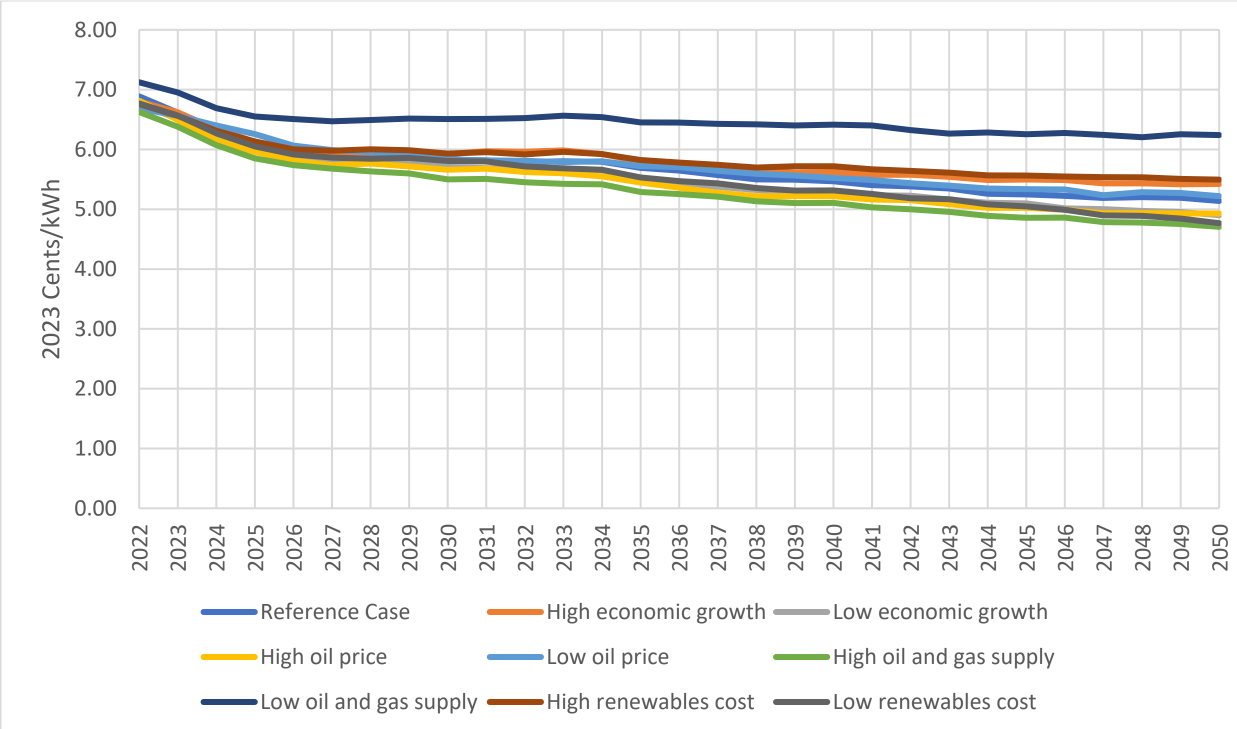

Figure 3 - US EIA Annual Energy Outlook 2022 Electricity Price Forecasts

Table 7 - EIA Forecast Variation by Case and Year (2023 cents per kWh)

	Ref. Case	High econ. growth	Low econ. growth	High oil price	Low oil price	High oil/gas supply	Low oil/gas supply	High renew. Cost	Low renew. cost	Side Case Difference from Ref. Case
2022	6.89	6.80	6.77	6.81	6.68	6.63	7.12	6.76	6.77	-3.8% to 3.4%
2035	5.69	5.80	5.52	5.45	5.72	5.29	6.45	5.82	5.53	-7.1% to +13.3%
2050	5.47	5.62	5.28	5.22	5.52	5.11	6.41	5.72	5.31	-6.6% to +17.3%

4.1.2 Energy Benefits Foregone

Combining the block-specific ratios presented in Table 6 with the long-term annual price forecast illustrated in Figure 3 produces an hourly price forecast for the megawatt-hours generated at Millers Ferry. Further combining this resulting price forecast with the generation estimates presented above (presented in part in Tables 4 and 5) produces estimates of the value of energy generated at Millers Ferry for each of this study's proposed alternatives. Table 8 summarizes these average annual impacts – "energy benefits" foregone - that the alternatives would have on generation at the dam during a 50-year period in monetary terms.

Table 8 - Average Annual Value of Generation at Millers Ferry and Energy Benefits Foregone

	Average Annual Value (2023$)				
	NAA	Alt 3	Alt 5d	Alt 12b	Alt 13b
Average annual value	10,672,742	9,269,071	9,808,604	9,807,715	9,265,738
Change from baseline	n/a	(782,963)	(243,431)	(244,320)	(786,297)
Percent change from baseline	n/a	-7.8%	-2.4%	-2.4%	-7.8%

4.2 Capacity Impacts

In the context of this study capacity value is defined as the product of the change in dependable capacity and its per-unit market value (price) reflecting the fixed costs of constructing replacement thermal generating plant capacity for the lost hydropower.

4.2.1 Dependable Capacity

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 available capacity in the load. *Dependable* capacity accounts for these factors by giving a measure of the amount of capacity that can be provided with some degree of reliability during peak demand periods.

Dependable capacity can be computed in several ways. The method that is most appropriate for evaluating the dependable capacity of a hydropower plant in a predominantly thermal generating plant-based power system is the Average Availability Method[2].

The occasional unavailability of a portion of a hydropower project's generating capacity due to hydrologic variations are treated in the same manner as the occasional unavailability of all or part of a thermal generating plant's generating capacity due to forced outages.

The dependable capacity calculation procedure for Millers Ferry begins with approximating the project's contribution in meeting the system capacity requirements demand for the regional critical year. Average weekly energy is used in this study because of characteristic hourly/daily/weekly cyclical peak energy demand during the annual low water (hydropower)/high energy demand 4-month period. Southeastern Power Administration determined the marketable capacity of 80 MW for Millers Ferry based on the regional drought in 1981.

[2] This method is described in Section 6-7g of EM 1110-2-1701, *Hydropower*, dated 31 December 1985.

The project's capacity contribution was determined by first calculating its weekly average generation (MWh) for the simulated peak demand months of June through September of 1981 (the project's critical water year as determined by SEPA) in the ResSim model baseline run. Average weekly energy is characteristic the hourly-daily-weekly cyclical peak energy demand during the annual low water/high energy demand 4-month period.

This number was then divided by SEPA's defined marketable capacity[3] (80 MW) for the project, yielding an estimate of the required/expected weekly hours of generation during the peak demand period for the project.

Next, the project's weekly average generation (MWh) during the peak demand months was calculated for each simulated year. Dividing the weekly average generation during peak months by the project's required/expected weekly average hours during peak months yields an array of potentially supportable capacity values. However, actual power produced is limited by the machine capability of the project. The actual supportable capacity for a given year is consequently the lesser of the potential supportable capacity and the project's the machine capability. With the average availability method, dependable capacity is the average actual supportable capacity over the period of record.

As an example of how dependable capacity is calculated, Table 9 shows the values described above for the no-action alternative baseline for simulation years 1980-2011 (not all simulation years or alternatives are displayed).

Table 9 - Supportable Capacity Calculations for Millers Ferry, 1980-2011

	Avg. Weekly Generation (MWh)	**Potential Supportable Capacity (MW)**	**Machine Capability (MW)**	**Actual Supportable Capacity (MW)**
1980	5,265	80	99	80
1981	5,283	80	99	80
1982	6,080	92	98	92
1983	5,247	79	97	79
1984	6,224	94	87	87
1985	6,394	97	96	96
1986	4,831	73	100	73
1987	4,862	74	99	74
1988	5,981	91	98	91
1989	6,693	101	79	79
1990	4,818	73	100	73

[3] Coordination with SEPA confirmed marketable capacity values for the Corps hydropower plants and the critical water year of 1981. SEPA's Marketable Capacity for Millers Ferry is 80 MW (email from Douglas Spencer, SEPA Hydraulic Engineer, dated Thursday 9/29/2022)

1991	6,933	105	95	95
1992	6,777	103	95	95
1993	5,168	78	100	78
1994	6,704	102	83	83
1995	5,689	86	100	86
1996	6,966	105	98	98
1997	6,881	104	97	97
1998	4,809	73	96	73
1999	6,060	92	92	92
2000	4,819	73	94	73
2001	6,064	92	96	92
2002	6,326	96	99	96
2003	6,583	100	78	78
2004	6,715	102	87	87
2005	7,590	115	79	79
2006	5,694	86	95	86
2007	3,721	56	96	56
2008	5,447	82	94	82
2009	5,765	87	90	87
2010	5,638	85	97	85
2011	5,658	86	96	86

The average availability (dependable capacity) of Millers Ferry across this study's proposed alternatives is summarized in Table 10 below.

Table 10 - Millers Ferry Dependable Capacity by Alternative

	MW	**Change from Baseline (MW)**
NAA	87	-
Alt 3	79	-9
Alt 5d	82	-5
Alt 12b	82	-5
Alt 13b	87	-1

4.2.2 Value of Dependable Capacity

Capacity value is an estimate of the fixed costs of the replacement capacity that would be needed to replace the capacity lost to operational, hydrological, or structural changes to hydropower resources. This value is calculated as the product of the change in dependable hydropower capacity (in MW) and its per-MW replacement cost (price), which is in turn based on the costs associated with the most likely combination of replacement resources.

To determine the most likely replacement resources for foregone hydropower capacity, three thermal resource types were considered: gas-fired combustion turbine, gas-fired combined cycle turbine, and coal steam plant, which reflect the primary thermal electric generation mix (Figure 4) and projected capacity additions in the region. The EIA AEO 2022 projects that through 2022, combined cycle turbine capacity will comprise a majority of combined planned and unplanned additions in the region.

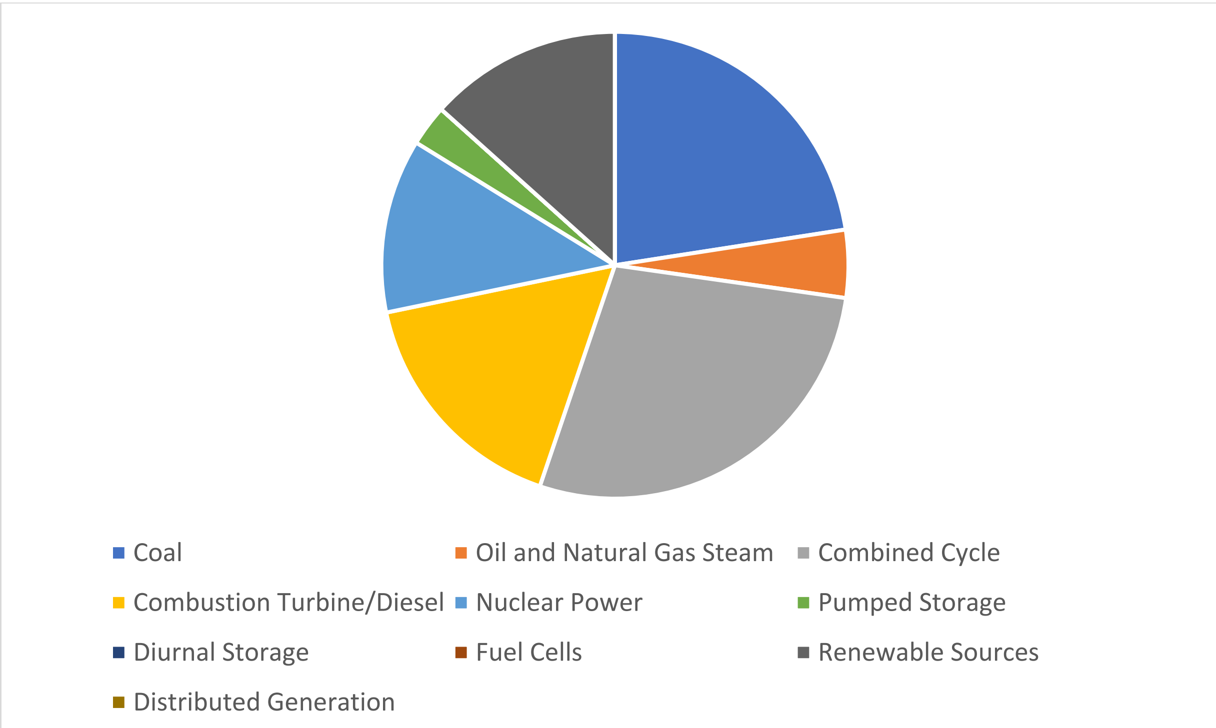

Figure 4 - Net Summer Electric Generating Capacity, SERC/SE Region, 2022

Per-MW capacity replacement values for the three resource types were estimated using information published primarily by the US EIA in conjunction with the 2020 and subsequent Annual Energy Outlook[4], with other sources as needed. The information includes overnight capital costs, fuel costs, heat rates, and operations and maintenance (O&M) costs. Table 11 summarizes the plant capacity and energy costs estimated for this analysis. Inputs to these estimates are included in the appendix.

[4] US EIA, Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies, 2020.

Table 11 - Plant Capacity and Energy Costs

	Capacity (2023$/kW-year)	Energy (2023$/MWh)
Coal	$371.80	$29.63
Combined Cycle Turbine	$91.03	$29.61
Combustion Turbine	$85.98	$45.47

A screening curve analysis is sometimes employed to establish a mix of replacement resources for foregone capacity. However, the latest published cost estimates establish that of the three resources considered, the two gas-fired plant types would be the only probable candidates. Further, the capacity and energy costs for the two gas-fired plants in Table 11 imply that combustion turbine generation would comprise a very small amount (likely less than 4%) of the replacement mix. It was thus assumed that the replacement resource would be combined cycle turbine capacity. Its corresponding capacity value was used to estimate the value of lost hydropower capacity - the "capacity benefits" foregone at Millers Ferry – under each of the study alternatives summarized in Table 12.

Table 12 - Capacity Benefits Foregone

	Dependable Capacity (MW)	Value of Dep. Capacity (2023$)	Change from Baseline
NAA	87	$7,949,252	$0
Alt 3	79	$7,174,499	-$774,753
Alt 5d	82	$7,506,616	-$442,636
Alt 12b	82	$7,505,949	-$443,303
Alt 13b	87	$7,877,219	-$72,033

4.3 Summary of Hydropower Benefits Foregone

Table 13 summarizes the total hydropower benefits foregone under each of the study's alternatives. The results in Table 13 are presented individually in the preceding sections (energy benefits foregone in Table 8, and capacity benefits foregone in Table 12). Because these estimates are based on the equivalent costs of the region's energy generation and capacity, they represent the replacement costs of hydropower.

Table 13 - Hydropower Benefits Foregone

	Annual Generation (MWh)	Energy Value (2023$)	Dependable Capacity (MW)	Value of Dep. Capacity (2023$)	Total Hydropower Value (2023$)	Hydropower Total Change from Baseline (2023$)
NAA	326,225	$10,672,742	87	$7,949,252	$18,621,994	$0
Alt 3	284,549	$9,269,071	79	$7,174,499	$16,443,570	-$2,178,424
Alt 5d	300,535	$9,808,604	82	$7,506,616	$17,315,220	-$1,306,774
Alt 12b	300,511	$9,807,715	82	$7,505,949	$17,313,664	-$1,308,330
Alt 13b	284,459	$9,265,738	87	$7,877,219	$17,142,956	-$1,479,038

4.4 Revenue Foregone

“Revenues foregone to hydropower are the reduction in revenues accruing to the U.S. Treasury as a result of the reduction in hydropower outputs based on the existing rates charged by the power marketing agency.”[5]

“The Corps does not market the power it produces; marketing is done by the Federal power marketing agencies (Southeastern Power Administration, Southwestern Power Administration, Western Area Power Administration, Bonneville Power Administration, Alaska Power Administration) through the Secretary of Energy. The rates are set by the marketing agency to: (a) recover costs (producing and transmitting) over a reasonable period of years (50 years usually); and (b) encourage widespread use at the lowest possible rates to consumers, consistent with sound business principles. …”[6]

Revenue foregone under this study’s alternatives is based on the current SEPA contract rates applicable to power generation by the Millers Ferry hydropower plants. The current rates are:

Energy Rate Total: $12.80/MWh

Monthly Capacity Charge: $4.04/kW-month

To compute energy revenues foregone, the contract energy rate is applied to the average contract energy foregone, and the capacity charge is applied to the foregone dependable capacity. Table 14 below summarize the revenues foregone for each of the alternatives.

[5] Engineer Manual ER 1105-2-100, 22 April 2000, “Planning Guidance Notebook”, Appendix E – Civil Works, Section VIII – Water Supply, E-57 Other Authorities, (d) Reallocation of Storage, (2) Cost of Storage, (b) Revenue Foregone, page E-217

[6] Engineer Manual ER 1105-2-100, 22 April 2000, “Planning Guidance Notebook”, Appendix E – Civil Works, Section VI – Hydroelectric Power, e-46 Special Considerations, b. Coordination Initiatives, (2) Marketing Agencies, page E-175.

Table 14 - Revenue by Alternative

	Energy (MWh)	Energy Revenue (2023$)	Dependable Capacity (MW)	Capacity Revenue (2023$)	Total Revenue (2023$)	Change from Baseline (2023$)
NAA	326,225	$4,175,679	87.32	$4,233,342	$8,409,021	$0
Alt 3	284,549	$3,642,226	78.81	$3,820,750	$7,462,977	-$946,044
Alt 5	300,535	$3,846,853	82.46	$3,997,618	$7,844,472	-$564,549
Alt 12	300,511	$3,846,545	82.45	$3,997,263	$7,843,808	-$565,213
Alt 13	284,459	$3,641,070	86.53	$4,194,981	$7,836,051	-$572,970

4.5 PMA Credits

4.5.1 Guidance

Project costs originally allocated to hydropower are being repaid through power revenues which are based on rates designed by the Federal power marketing agency (PMA) to recover allocated costs plus interest within 50 years of the date of commercial power operation. If a portion of available water is reallocated for fish passage purposes, the PMA's repayment obligation must be reduced in proportion to the lost energy and marketable capacity.

Planning Guidance Notebook, Appendix E-57d(3) of ER 1105-2-100 (22 April 2002) states that;

"If hydropower revenues are being reduced as a result of the reallocation, the power marketing agency will be credited for the amount of revenues to the Treasury foregone as a result of the reallocation assuming uniform annual repayment."

Paragraph d(2)(b) states;

"Revenues foregone to hydropower are the reduction in revenues accruing to the Treasury because of the reduction in hydropower outputs based on the Baseline rates charged by the power marketing agency. Revenues foregone from other project purposes are the reduction in revenues accruing to the Treasury based on any Baseline repayment agreements."

ER 1105-2-100 also allows the marketing agency credit for any additional costs above the lost revenue to recover costs of purchased power to meet the obligations of the current power sales contract(s) relating to the marketing of power from the hydro project(s) where storage is being reallocated. The continuation of Appendix E-57d(3), provides the following guidance:

"In instances where Baseline contracts between the power marketing agency and their customer would result in a cost to the Federal Government to acquire replacement power to fulfill the obligations of contracts, an additional credit to the power marketing agency can be made for such costs incurred during the remaining period of the contracts."

In both cases the credit in each year will be based on the revenue actually lost or the replacement costs actually incurred (and documented) by the power marketing agency.

4.5.2 Estimate of Credits

The estimate of credit to the PMA will in this context be the same as the estimated revenue foregone, which is based on the change in energy and capacity between an alternative and a base Case (no-action alternative) multiplied by the SEPA contract rates discussed above. Additional credit will be based on revenue actually lost or replacement costs actually incurred.

5 Appendix

5.1 Annual Average Generation at Millers Ferry by Month and Generation Block

No Action Alternative (NAA)

	Average MWh			
	Contract	**Peak**	**Off Peak**	**Weekend**
1	13,410	4,174	3,624	8,576
2	10,410	3,817	4,074	6,933
3	10,102	3,831	4,079	7,267
4	7,390	9,434	3,402	8,083
5	10,329	10,570	2,604	9,487
6	11,331	8,003	1,081	8,127
7	11,690	7,304	1,226	8,021
8	11,908	5,371	480	7,106
9	11,342	3,711	460	5,987
10	15,343	982	555	6,634
11	16,022	2,088	1,521	7,638
12	16,105	3,515	2,339	8,741
Block Total	**145,382**	**62,800**	**25,444**	**92,599**
Grand Total	**326,225**			

Alt 3

	Average MWh			
	Contract	**Peak**	**Off Peak**	**Weekend**
1	12,853	3,598	3,079	7,899
2	10,216	3,445	3,633	6,522
3	9,949	3,512	3,561	6,863
4	7,314	8,398	2,865	7,419
5	10,142	8,613	2,121	8,427
6	10,866	5,607	834	6,896
7	10,853	5,170	974	6,735

8	10,784	3,206	383	5,729
9	9,736	2,124	355	4,670
10	12,377	718	436	5,284
11	13,743	1,667	1,253	6,452
12	14,777	2,809	1,917	7,762
Block Total	**133,610**	**48,868**	**21,414**	**80,657**
Grand Total	**284,549**			

Alt 5d

	Average MWh			
	Contract	**Peak**	**Off Peak**	**Weekend**
1	13,083	3,803	3,259	8,148
2	10,300	3,576	3,790	6,674
3	10,018	3,624	3,745	7,012
4	7,344	8,787	3,049	7,664
5	10,231	9,339	2,285	8,821
6	11,123	6,465	912	7,366
7	11,299	5,886	1,056	7,231
8	11,396	3,900	415	6,271
9	10,553	2,579	389	5,193
10	13,582	799	476	5,817
11	14,657	1,801	1,347	6,906
12	15,327	3,048	2,056	8,133
Block Total	**138,913**	**53,607**	**22,779**	**85,237**
Grand Total	**300,535**			

Alt 12b

	Average MWh			
	Contract	**Peak**	**Off Peak**	**Weekend**
1	13,083	3,803	3,259	8,148
2	10,300	3,576	3,790	6,674
3	10,018	3,624	3,745	7,012
4	7,344	8,787	3,049	7,664
5	10,231	9,339	2,285	8,821
6	11,123	6,465	912	7,366
7	11,298	5,886	1,056	7,230
8	11,391	3,900	415	6,271
9	10,546	2,579	389	5,190
10	13,578	799	476	5,815
11	14,657	1,801	1,347	6,906
12	15,326	3,048	2,056	8,133
Block Total	**138,896**	**53,607**	**22,779**	**85,229**

Grand Total 300,511

Alt 13b

	Average MWh			
	Contract	**Peak**	**Off Peak**	**Weekend**
1	12,853	3,598	3,079	7,899
2	10,216	3,445	3,633	6,522
3	9,949	3,512	3,561	6,863
4	7,314	8,398	2,865	7,419
5	10,142	8,613	2,121	8,427
6	10,865	5,607	834	6,893
7	10,849	5,170	974	6,730
8	10,769	3,206	383	5,727
9	9,712	2,124	355	4,660
10	12,362	718	436	5,276
11	13,741	1,667	1,253	6,452
12	14,775	2,809	1,917	7,762
Block Total	**133,547**	**48,868**	**21,414**	**80,630**
Grand Total	**284,459**			

5.2 Dependable Capacity Calculation for Millers Ferry by Alternative

No Action Alternative (NAA)

Year	Avg. weekly energy (MWh)	Potential supportable capacity (MW)	Machine capability (MW)	Actual supportable capacity (MW)
1940	6,390	97	80	80
1941	6,938	105	91	91
1942	7,233	110	95	95
1943	6,149	93	97	93
1944	5,335	81	98	81
1945	6,960	105	99	99
1946	6,132	93	92	92
1947	6,612	100	98	98
1948	5,494	83	93	83
1949	7,017	106	91	91
1950	8,354	126	87	87
1951	6,217	94	98	94
1952	5,709	86	99	86

1953	6,416	97	97	97
1954	5,693	86	97	86
1955	6,266	95	98	95
1956	5,003	76	97	76
1957	6,892	104	98	98
1958	7,463	113	93	93
1959	7,707	117	99	99
1960	5,951	90	99	90
1961	5,632	85	94	85
1962	5,122	78	99	78
1963	6,393	97	97	97
1964	5,654	86	97	86
1965	5,545	84	98	84
1966	6,875	104	99	99
1967	8,148	123	84	84
1968	6,284	95	98	95
1969	6,583	100	98	98
1970	7,334	111	99	99
1971	6,558	99	92	92
1972	5,898	89	99	89
1973	5,078	77	96	77
1974	6,068	92	94	92
1975	6,633	100	77	77
1976	6,585	100	95	95
1977	6,012	91	99	91
1978	5,863	89	99	89
1979	7,023	106	92	92
1980	5,265	80	99	80
1981	5,283	80	99	80
1982	6,080	92	98	92
1983	5,247	79	97	79
1984	6,224	94	87	87
1985	6,394	97	96	96
1986	4,831	73	100	73
1987	4,862	74	99	74
1988	5,981	91	98	91
1989	6,693	101	79	79
1990	4,818	73	100	73
1991	6,933	105	95	95
1992	6,777	103	95	95
1993	5,168	78	100	78
1994	6,704	102	83	83
1995	5,689	86	100	86

1996	6,966	105	98	98
1997	6,881	104	97	97
1998	4,809	73	96	73
1999	6,060	92	92	92
2000	4,819	73	94	73
2001	6,064	92	96	92
2002	6,326	96	99	96
2003	6,583	100	78	78
2004	6,715	102	87	87
2005	7,590	115	79	79
2006	5,694	86	95	86
2007	3,721	56	96	56
2008	5,447	82	94	82
2009	5,765	87	90	87
2010	5,638	85	97	85
2011	5,658	86	96	86
Average				**87**

Alt 3

Year	Avg. weekly energy (MWh)	Potential supportable capacity (MW)	Machine capability (MW)	Actual supportable capacity (MW)
1940	5,503	83	80	80
1941	5,888	89	91	89
1942	6,354	96	95	95
1943	5,311	80	97	80
1944	4,500	68	98	68
1945	6,084	92	99	92
1946	5,446	82	92	82
1947	5,894	89	98	89
1948	4,775	72	93	72
1949	6,340	96	91	91
1950	7,446	113	87	87
1951	5,342	81	98	81
1952	4,807	73	99	73
1953	5,692	86	97	86
1954	4,871	74	97	74

1955	5,289	80	98	80
1956	4,163	63	97	63
1957	6,152	93	98	93
1958	6,625	100	93	93
1959	6,862	104	99	99
1960	5,093	77	99	77
1961	4,865	74	94	74
1962	4,322	65	99	65
1963	5,530	84	97	84
1964	4,964	75	97	75
1965	4,669	71	98	71
1966	6,019	91	99	91
1967	7,411	112	84	84
1968	5,386	82	98	82
1969	5,679	86	98	86
1970	6,415	97	99	97
1971	5,876	89	92	89
1972	5,106	77	99	77
1973	4,477	68	96	68
1974	5,238	79	94	79
1975	6,112	93	77	77
1976	5,827	88	95	88
1977	5,183	78	99	78
1978	4,937	75	99	75
1979	6,393	97	92	92
1980	4,517	68	99	68
1981	4,275	65	99	65
1982	5,369	81	98	81
1983	4,637	70	97	70
1984	5,563	84	87	84
1985	5,378	81	96	81
1986	3,801	58	100	58
1987	3,970	60	99	60
1988	4,901	74	98	74
1989	6,105	92	79	79
1990	4,035	61	100	61
1991	6,149	93	95	93
1992	6,069	92	95	92
1993	4,349	66	100	66
1994	5,966	90	83	83
1995	4,917	74	100	74
1996	6,201	94	98	94
1997	6,236	94	97	94

1998	4,083	62	96	62
1999	5,146	78	92	78
2000	3,991	60	94	60
2001	5,172	78	96	78
2002	5,503	83	99	83
2003	5,974	90	78	78
2004	5,925	90	87	87
2005	6,739	102	79	79
2006	4,934	75	95	75
2007	2,854	43	96	43
2008	4,521	68	94	68
2009	5,185	79	90	79
2010	4,900	74	97	74
2011	4,894	74	96	74
Average				**79**

Alt 5d

Year	Avg. weekly energy (MWh)	Potential supportable capacity (MW)	Machine capability (MW)	Actual supportable capacity (MW)
1940	5,822	88	80	80
1941	6,271	95	91	91
1942	6,671	101	95	95
1943	5,613	85	97	85
1944	4,803	73	98	73
1945	6,401	97	99	97
1946	5,693	86	92	86
1947	6,155	93	98	93
1948	5,033	76	93	76
1949	6,583	100	91	91
1950	7,777	118	87	87
1951	5,676	86	98	86
1952	5,147	78	99	78
1953	5,964	90	97	90
1954	5,265	80	97	80
1955	5,661	86	98	86
1956	4,499	68	97	68
1957	6,420	97	98	97
1958	6,930	105	93	93
1959	7,167	109	99	99

1960	5,406	82	99	82
1961	5,141	78	94	78
1962	4,618	70	99	70
1963	5,847	89	97	89
1964	5,214	79	97	79
1965	4,987	76	98	76
1966	6,330	96	99	96
1967	7,676	116	84	84
1968	5,733	87	98	87
1969	6,008	91	98	91
1970	6,753	102	99	99
1971	6,122	93	92	92
1972	5,392	82	99	82
1973	4,694	71	96	71
1974	5,537	84	94	84
1975	6,300	95	77	77
1976	6,104	92	95	92
1977	5,482	83	99	83
1978	5,274	80	99	80
1979	6,623	100	92	92
1980	4,790	73	99	73
1981	4,679	71	99	71
1982	5,633	85	98	85
1983	4,862	74	97	74
1984	5,801	88	87	87
1985	5,744	87	96	87
1986	4,214	64	100	64
1987	4,322	65	99	65
1988	5,302	80	98	80
1989	6,317	96	79	79
1990	4,326	66	100	66
1991	6,439	97	95	95
1992	6,325	96	95	95
1993	4,651	70	100	70
1994	6,235	94	83	83
1995	5,208	79	100	79
1996	6,482	98	98	98
1997	6,475	98	97	97
1998	4,382	66	96	66
1999	5,519	84	92	84
2000	4,403	67	94	67
2001	5,508	83	96	83
2002	5,834	88	99	88

2003	6,199	94	78	78
2004	6,272	95	87	87
2005	7,051	107	79	79
2006	5,299	80	95	80
2007	3,331	50	96	50
2008	4,950	75	94	75
2009	5,404	82	90	82
2010	5,242	79	97	79
2011	5,268	80	96	80
Average				**82**

Alt 12b

Year	Avg. weekly energy (MWh)	Potential supportable capacity (MW)	Machine capability (MW)	Actual supportable capacity (MW)
1940	5,822	88	80	80
1941	6,271	95	91	91
1942	6,671	101	95	95
1943	5,613	85	97	85
1944	4,803	73	98	73
1945	6,401	97	99	97
1946	5,693	86	92	86
1947	6,155	93	98	93
1948	5,033	76	93	76
1949	6,583	100	91	91
1950	7,777	118	87	87
1951	5,676	86	98	86
1952	5,147	78	99	78
1953	5,964	90	97	90
1954	5,259	80	97	80
1955	5,661	86	98	86
1956	4,499	68	97	68
1957	6,420	97	98	97
1958	6,930	105	93	93
1959	7,167	109	99	99
1960	5,406	82	99	82
1961	5,141	78	94	78
1962	4,618	70	99	70
1963	5,847	89	97	89
1964	5,214	79	97	79

1965	4,987	76	98	76
1966	6,330	96	99	96
1967	7,676	116	84	84
1968	5,733	87	98	87
1969	6,008	91	98	91
1970	6,753	102	99	99
1971	6,122	93	92	92
1972	5,392	82	99	82
1973	4,694	71	96	71
1974	5,537	84	94	84
1975	6,300	95	77	77
1976	6,104	92	95	92
1977	5,482	83	99	83
1978	5,274	80	99	80
1979	6,623	100	92	92
1980	4,790	73	99	73
1981	4,679	71	99	71
1982	5,633	85	98	85
1983	4,862	74	97	74
1984	5,801	88	87	87
1985	5,744	87	96	87
1986	4,214	64	100	64
1987	4,322	65	99	65
1988	5,302	80	98	80
1989	6,317	96	79	79
1990	4,326	66	100	66
1991	6,439	97	95	95
1992	6,325	96	95	95
1993	4,651	70	100	70
1994	6,235	94	83	83
1995	5,208	79	100	79
1996	6,482	98	98	98
1997	6,475	98	97	97
1998	4,382	66	96	66
1999	5,519	84	92	84
2000	4,392	67	94	67
2001	5,508	83	96	83
2002	5,834	88	99	88
2003	6,199	94	78	78
2004	6,271	95	87	87
2005	7,051	107	79	79
2006	5,293	80	95	80
2007	3,331	50	96	50

2008	4,950	75	94	75
2009	5,404	82	90	82
2010	5,238	79	97	79
2011	5,259	80	96	80
Average				**82**

Alt 13b

Year	Avg. weekly energy (MWh)	Potential supportable capacity (MW)	Machine capability (MW)	Actual supportable capacity (MW)
1940	5,503	83	80	80
1941	4,769	72	91	72
1942	6,949	105	95	95
1943	7,953	120	97	97
1944	8,781	133	98	98
1945	7,814	118	99	99
1946	9,846	149	92	92
1947	8,847	134	98	98
1948	12,027	182	93	93
1949	8,864	134	91	91
1950	4,859	74	87	74
1951	5,692	86	98	86
1952	7,351	111	99	99
1953	10,030	152	97	97
1954	3,933	60	97	60
1955	4,880	74	98	74
1956	7,210	109	97	97
1957	8,180	124	98	98
1958	7,166	109	93	93
1959	6,180	94	99	94
1960	7,276	110	99	99
1961	9,422	143	94	94
1962	8,384	127	99	99
1963	7,415	112	97	97
1964	11,914	180	97	97
1965	8,358	127	98	98
1966	8,309	126	99	99
1967	7,586	115	84	84
1968	7,165	108	98	98
1969	6,476	98	98	98

1970	6,749	102	99	99
1971	9,644	146	92	92
1972	8,752	133	99	99
1973	11,091	168	96	96
1974	7,662	116	94	94
1975	15,002	227	77	77
1976	10,106	153	95	95
1977	7,298	111	99	99
1978	6,030	91	99	91
1979	10,600	161	92	92
1980	9,852	149	99	99
1981	3,579	54	99	54
1982	8,983	136	98	98
1983	11,827	179	97	97
1984	7,954	120	87	87
1985	5,062	77	96	77
1986	2,860	43	100	43
1987	6,130	93	99	93
1988	3,660	55	98	55
1989	7,853	119	79	79
1990	8,516	129	100	100
1991	6,030	91	95	91
1992	8,235	125	95	95
1993	7,498	114	100	100
1994	7,087	107	83	83
1995	7,155	108	100	100
1996	7,311	111	98	98
1997	8,931	135	97	97
1998	9,635	146	96	96
1999	3,250	49	92	49
2000	2,561	39	94	39
2001	6,391	97	96	96
2002	5,005	76	99	76
2003	11,113	168	78	78
2004	6,354	96	87	87
2005	9,061	137	79	79
2006	5,167	78	95	78
2007	2,874	44	96	44
2008	2,945	45	94	45
2009	10,816	164	90	90
2010	9,466	143	97	97
2011	3,328	50	96	50
Average				**87**

5.3 Capacity Value Estimate Inputs

Natural Gas Combined Cycle Turbine

Input	Value
Year of interest[7]	2021
EIA Region	SRSE
Handy-Whitman Region	2
OCC Estimate Year	2019
Overnight Capital Cost ($/kW)	$984.94
Discount rate/Borrowing rate	2.50%
Plant life	40
Depreciation rate	2.5%
Fixed O&M ($/kW/yr)	$13.73
Variable O&M ($/MWh)	$2.31
Fuel cost ($/MWh)	$25.58
Plant Factor	87%
Total Capacity Payment	**$77.60**
Other variables and adjustments:	
Hydro flex value	2.5%
Hydro flex value adjustment	$1.94
Plant mechanical availability	90%
Hydro mechanical availability	98%
Mechanical availability adjustment	$6.21
Total adjustments	**$8.15**
Total Capacity Value ($/kW/yr)	**$85.74**
Total Energy Value ($/MWh)	**$27.89**

Combustion Turbine

Input	Value
Year of interest[7]	2021
EIA Region	SRSE
Handy-Whitman Region	2
OCC Estimate Year	2019
Overnight Capital Cost ($/kW)	$942.59
Discount rate/Borrowing rate	2.50%

[7] Note that the results of this estimate were subsequently indexed to FY 2023 dollars

Plant life	40
Depreciation rate	2.5%
Fixed O&M ($/kW/yr)	$12.17
Variable O&M ($/MWh)	$4.80
Fuel cost ($/MWh)	$38.02
Plant Factor	10%
Total Capacity Payment	**$73.28**
<u>Other variables and adjustments:</u>	
Hydro flex value	2.5%
Hydro flex value adjustment	$1.83
Plant mechanical availability	90%
Hydro mechanical availability	98%
Mechanical availability adjustment	$5.86
Total adjustments	**$7.69**
Total Capacity Value ($/kW/yr)	**$80.98**
Total Energy Value ($/MWh)	**$42.83**

<u>Coal Steam Plant</u>

Input	**Value**
Year of interest[7]	2021
EIA Region	SRSE
Handy-Whitman Region	2
OCC Estimate Year	2019
Overnight Capital Cost ($/kW)	$3,923.41
Discount rate/Borrowing rate	2.50%
Plant life	40
Depreciation rate	2.5%
Fixed O&M ($/kW/yr)	$42.38
Variable O&M ($/MWh)	$4.70
Fuel cost ($/MWh)	$23.21
Plant Factor	65%
Total Capacity Payment	**$296.76**
<u>Other variables and adjustments:</u>	
Hydro flex value	5.0%
Hydro flex value adjustment	$14.84

Plant mecha~~e~~nical availability	85%
Hydro mechanical availability	98%
Mechanical availability adjustment	$38.58
Total adjustments	**$53.42**
Total Capacity Value ($/kW/yr)	**$350.18**
Total Energy Value ($/MWh)	**$27.91**