US Army Corps of Engineers®
Wilmington District

PHILPOTT LAKE, VIRGINIA
WATER STORAGE REALLOCATION
INTEGRATED FEASIBILITY STUDY AND ENVIRONMENTAL ASSESSMENT

APPENDIX D: HYDROPOWER ANALYSIS

Final Report
February 2023

US Army Corps
of Engineers
Portland District

Philpott Dam and Lake

HYDROELECTRIC DESIGN CENTER

Philpott Lake

Water Supply Storage Reallocation Study

Project Impacts to Hydropower

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ABSTRACT

This report presents an analysis of impacts to hydropower at Philpott Lake hydropower plant resulting from an re-allocation of reservoir storage to furnish 6.19 cfs (cubic-feet per second) or about 4 MGD (million gallons per day) for Henry County Public Service Authority serving municipal water supplies. Water to meet this demand will flow through the hydropower plant's secondary unit (that runs continuously) and be withdrawn from the river below or downstream of Philpott Dam. Project operations modified to meet water supply demand makes a very small increase annual generation, and very small decrease in dependable capacity.

Philpott hydropower plant has three units for a combined Output of 15 MWs, two main units and a small house unit. Electrical power generated at Philpott hydropower plants is dispatched by Dominion Power, wheeled through Appalachian Power to Virginia Electric and Power Company System to customers of power from Philpott. Power from Philpott is marketed to customers under contract with Southeastern Power Administration of the US Department of Energy.

Water flow operations through the power plant for the period of record (1960-2019) is made using HEC-RESSIM, a sequential streamflow model to simulate daily Philpott Lake operations under alternative operations for water supply.

Simulated generation dispatch was developed from plant operations data available for 2010-2014. Daily averages were converted to ratios of weekly power flow for each month which were applied to weekly power plant flow volumes from HEC-RESSIM model output. Daily power was then computed and validated using the available plant operations data.

Table A-1 below summarizes the Annual Hydropower Benefits Foregone.

Table A - 1. Estimated Annual Hydropower Benefits Under Base Case and Alternative Scenarios

	Annual Energy Benefits (foregone)				Annual Capacity Benefits (foregone)				Total Annual Hydropower Benefits (foregone)	
	MWh	Δ (MWh)	2023$	Δ ($)	MW	Δ (MW)	2023$	Δ ($)	2023$	Δ ($)
Base Case	22,770	n/a	$745,608	n/a	14.85	n/a	$1,505,234	n/a	$2,250,842	n/a
Reallocation from Cons. Pool	22,786	16	$746,761	$1,153	14.80	-0.05	$1,500,215	($5,019)	$2,246,976	($3,866)
Reallocation from Inactive Pool	23,227	457	$756,580	$10,972	14.79	-0.05	$1,499,673	($5,561)	$2,256,253	$5,411

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1 Introduction

The U.S. Army Corps of Engineers (USACE), Wilmington District is conducting a study of Philpott Lake Water Supply Storage. The water supply study will evaluate a Municipal Water Supply request by the Henry County Public Service Authority for water supply storage in Philpott Lake. Water to meet this demand will flow through the hydropower plant's secondary unit (that runs continuously) and be withdrawn from the river below or downstream of Philpott Dam

This report presents an analysis of the effects on hydropower and the monetary value hydropower that are expected to result from proposed changes to water control operations at Philpott hydropower plant. The hydropower values for energy and capacity are computed for the baseline condition, representing current water control operations, and for alternative flow scenarios associated with these studies.

1.1 Calculation of Hydropower

The calculations of hydropower energy and capacity values are based on 60 years of historic hydrology (1960-2019) using the HEC-RESSIM model.

To understand how system operations can affect hydropower generation we will first consider the mathematics used to approximate the amount of power produced from a hydropower facility, the power equation (Eq. 1). This equation shows that power is directly proportional to three variables: the efficiency of the plant turbines, the amount of flow going through the turbines, and the head, the height of the water in the reservoir relative to its height after discharge.

$$P = e * g * Q * H$$

Where; P=power (kW),
e=turbine efficiency,
g = gravitational constant (ft/sec^2),
Q-flow (cfs),
H=head (ft).

Reservoir operations can affect all three of these variables. Higher or lower operational reservoir elevations change the head. Maximum or minimum flow requirements used for flood risk management and environmental purpose can affect the flow. Although power is linear in both head and flow, this relationship quickly becomes non-linear with the inclusion of efficiency which is a non-linear function of both head and flow.

1.2 Hydropower Impact Components

In general, the hydropower values resulting from generation can be divided into two components: energy values and capacity values. A change in energy value is the result of a change in the amount of water that is available to pass through the turbines. The value changes both daily and seasonally as a function of the systems electrical load. For example, energy may be more valuable during the height of the summer heat while businesses and residents are attempting to cool their environments as opposed to the fall or winter when air conditioners maybe turned off. The capacity value is a measure of the amount of capacity that the project can reliably contribute towards meeting system peak power demands.

1.2.1 Energy

Energy generation and the value of energy (generation) calculated in Chapter 3 is based upon the cost of utilizing the most likely alternative thermal source for power. For example, if an operational strategy reduces hydropower storage or flow, the loss in energy value is equivalent to the cost of replacing the lost power with the most likely alternative thermal source of power.

1.2.2 Capacity

There may be a decrease in the amount of capacity that the hydropower plant can contribute to the peak system load making it necessary to replace this lost capacity with an alternative source of power made up of a combination of thermal generating plants. Capacity and its value are the subject of Chapter 4.

2 Regional (WV, VA, NC) Bulk Power System Overview

This chapter contains the following: an overview of the power generation system for the 3-State region (WV, VA, NC) where electric power from Philpott Lake with an emphasis on hydropower, a descriptive analysis of the potential annual and seasonal changes in hydropower production due to water control management decisions, and a description of the process of calculating the changes in the energy and capacity value of the 3-State region resulting from the study alternatives.

2.1 Location of Philpott and John H Kerr USACE Projects

Philpott Lake is located upstream of Kerr reservoir on the Smith River. The Smith River flows into the Dan River, which flows into the Kerr project. Philpott Lake and Kerr projects are operated as a system for hydropower production.

The Smith River Basin watershed upstream of Philpott Lake lies primarily in the State of Virginia.

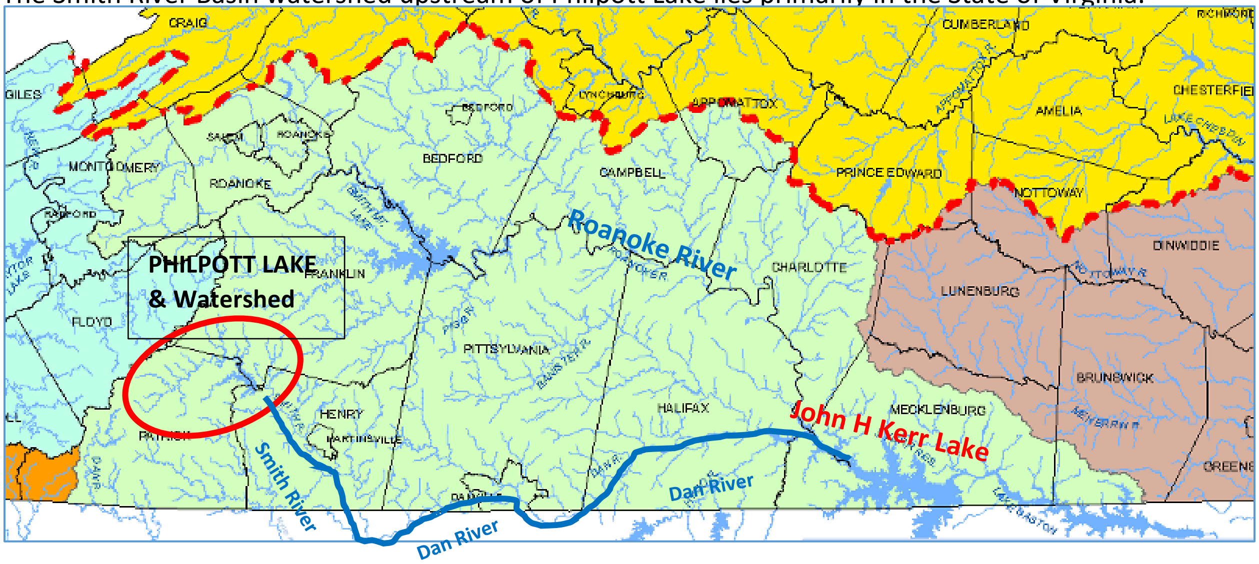

Figure 2-1. River Map- -Philpott Lake is on the Smith River, a tributary to John H Kerr Lake

2.2 PJM/Dominion System Capacity & Power

PJM/Dominion is responsible for improving the electric power generation critical infrastructure in VA, WV and NC region.

The region has undergone a significant increase in natural gas-fired generating plant capacity. Natural gas and Nuclear are equal at 32% of total system capacity and Coal is 30%. Nuclear and Hydroelectric energy makes up about 4 percentage points of the remaining 5% generating plant capacity (Figure 2-2).

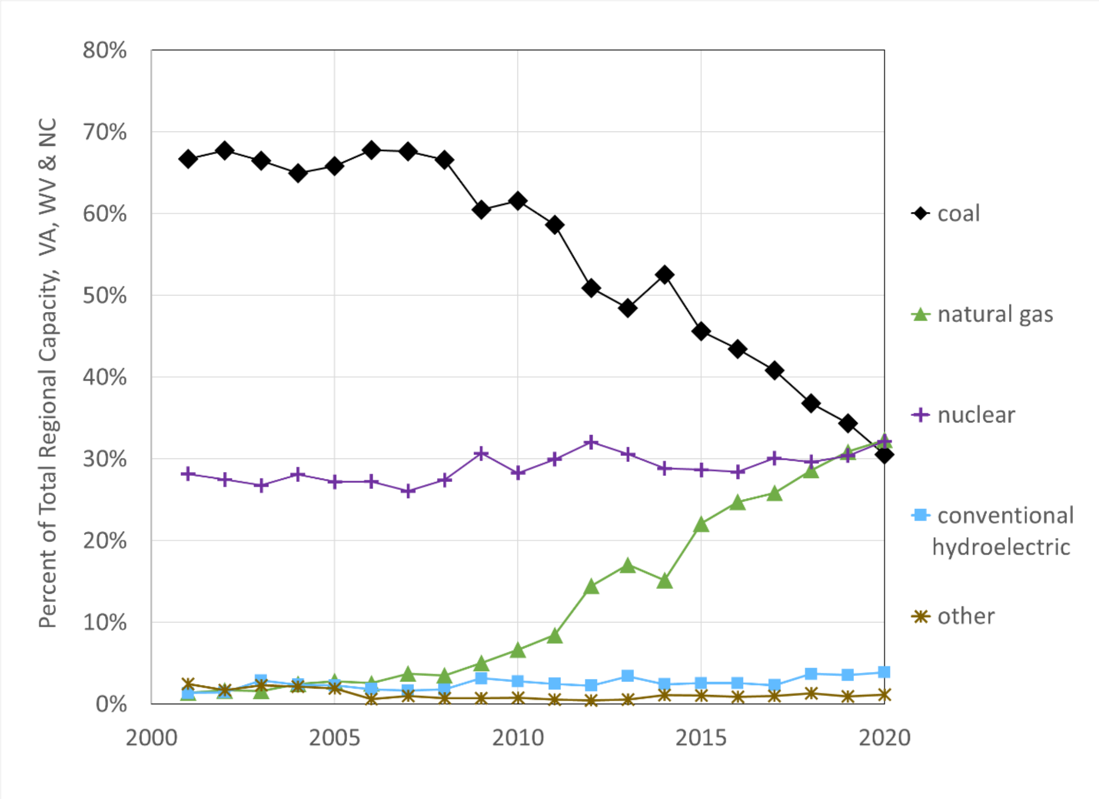

Figure 2-2. Historical trends for regional capacity for the States West Virginia, Virginia, and North Carolina.

Coal and nuclear power are predominately run as base load plants, facilities that produce constant rates of generation to meet the systems continuous regional demands. Natural gas and hydropower plants on the other hand are generally run as peaking load plants, meeting the daily and seasonal peak loads throughout the region. This is important, to conceptually understand which alternative thermal plants might be used to replace hydropower if changes in operations dictated such a need. As an illustrative example consider the 2019 generation pattern reported by the (EIA) for the states of West Virginia, Virginia, and North Carolina (Figure 2-3). Increases (decreases) in percent of peaking load generation for hydropower and natural gas plants are mirrored by decreases (increases) in percent generation for coal and nuclear. It would then seem that the replacement for conventional hydropower would be natural gas.

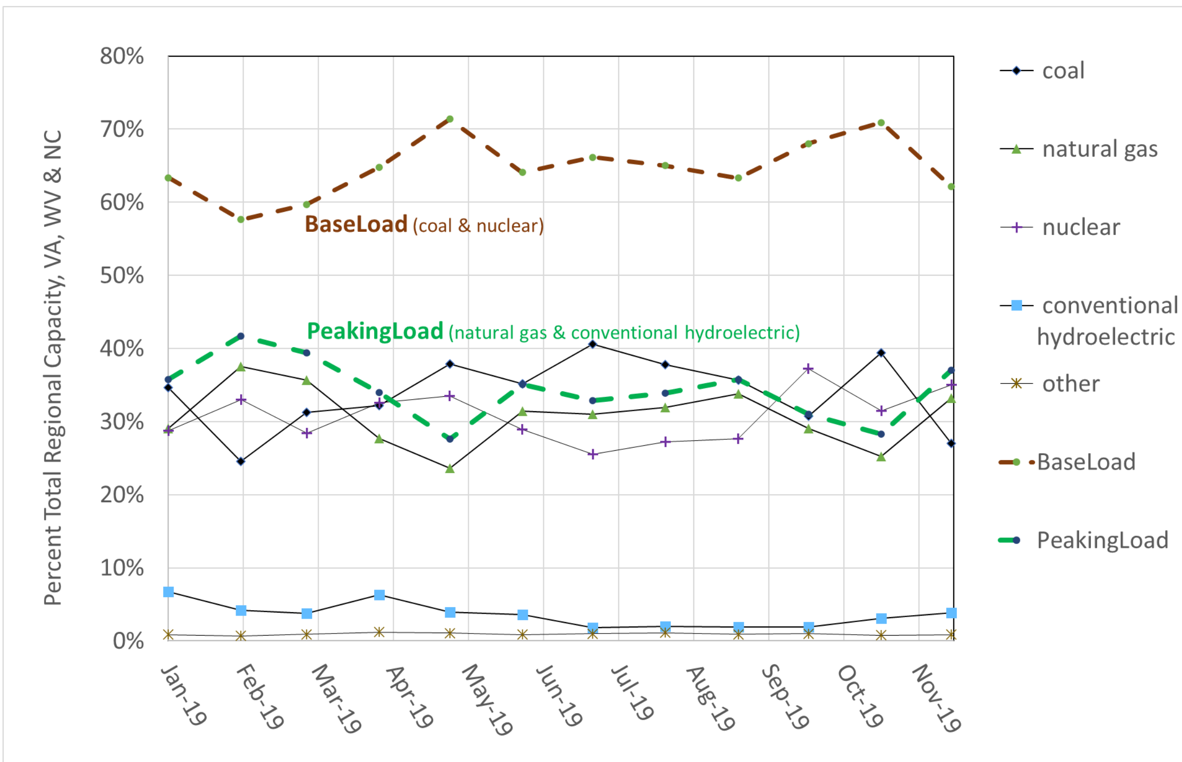

Figure 2-3. Percent of Monthly Capacity by Fuel Type for the States of West Virginia, Virginia, and North Carolina

2.3 Philpott Dam Hydropower Plant

The full potential of the dam was realized in 1953 with the completion of the powerhouse and the start-up of three generators having a combined output of about 15,200 kilowatts. There are two 7,500 kilowatt main units that are scheduled to meet customer power needs and a 200-kilowatt secondary unit that runs continuously to primarily power the hydropower plant. Slightly higher releases through the secondary unit is how the water supply would be released if the reallocation is approved.

Today, Philpott's electrical power enters a sophisticated grid system which distributes the power where needed to satisfy electrical needs equivalent to that of 1,600 homes. Powerhouse personnel control a delicate balance between the upstream and downstream sides of the dam which is 920 feet-long by 220 feet-high. Three distinct levels or layers of the lake are maintained. The lowest lake layer, the inactive storage pool, provides the minimum water pressure necessary to operate the power plant, even in low-water, drought conditions. The middle layer, the conservation storage pool, has more flexibility and is constantly adjusted for normal operation of the generators and to regulate flow of the Smith River. Proper stream flow ensures a healthy downstream ecosystem and provides an adequate water supply to communities dependent on the river. The top layer of the lake area is normally empty and is reserved for the collection and holding of potential flood waters during periods of heavy rainfall. At the top of the flood pool, Philpott Dam is holding back enough water to increase the lake size by 1000 acres. Without the dam and lake, flood waters would devastate communities along the river. Powerhouse personnel carefully control the release of the extra water in the flood pool through generation or by opening the dam's sluice gates, making room for the next flood.

2.3.1 Appalachian Power

Appalachian Power serves about 1 million customers in West Virginia, Virginia and Tennessee. Its headquarters is in Charleston, W. Va., with regulatory and external affairs offices in both Charleston, W. Va. and Richmond, Va.

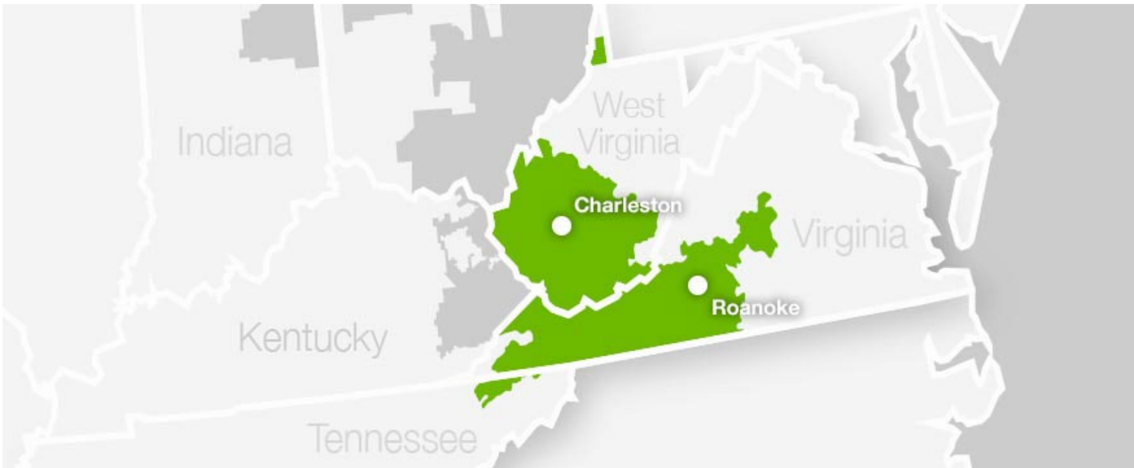

Figure 2-4. Service Area for Appalachian Power

Table 2-1. Appalachian Power Facts, 2018

Customer Information			
Total Customers 1.07 million			
	WV	VA	TN
Residential	390,054	452,352	41,895
Commercial	72,067	70,354	5,837
Industrial	2,489	1,882	164
Other	868	7,091	136
Total	465,478	531,679	48,032
Operating Information			
	WV	VA	TN
2018 electric sales (MWh)	17,465,815	15, 287,431	2,086,994
Average use per residential customer (kWh/year)	14,949	14,142	16,351
Average cost (residential) (cents per kWh)	11.75	11.68	9.06
Size of service area (operational) (square miles)	9,196	11,031	297
Size of distribution system (miles)	21,871	31,033	1,580
Size of transmission system (miles)	3,413	2,922	278
Total AEP Employees	2,066	1,052	79
	APCO	KINGSPORT	WHEELING
2018 net plant in service ($ million)	10,700	153	912

Appalachian Power is an operating company of the American Electric Power (AEP) system. AEP is one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 32,000 megawatts of generating capacity in the U.S.

2.4 Study Alternatives

- **Base Case:** This is the Current Condition (which includes continued current operations at Philpott and water supply withdrawals by Henry County Public Service Authority up to their currently permitted limit with no reservoir storage allocation.
- **Reallocation from Conservation Pool:** Reallocation of reservoir storage from Conservation Pool (6 cfs for Henry County PSA)
- **Reallocation from Inactive Storage Pool:** Reallocation of reservoir storage from the Inactive Storage Pool (6 cfs for Henry County PSA)

2.5 Hydropower Generation

To determine the change in energy generation resulting from the Studies' Alternative Plans, an analysis was performed to determine the average annual energy generated in the Base Case, current condition, using the 60-year HEC-RESSIM Model simulation period. As shown in Figure 2-5 there is a 0.07% and 2.01% increase in average annual energy, respectively, when compared to the baseline condition.

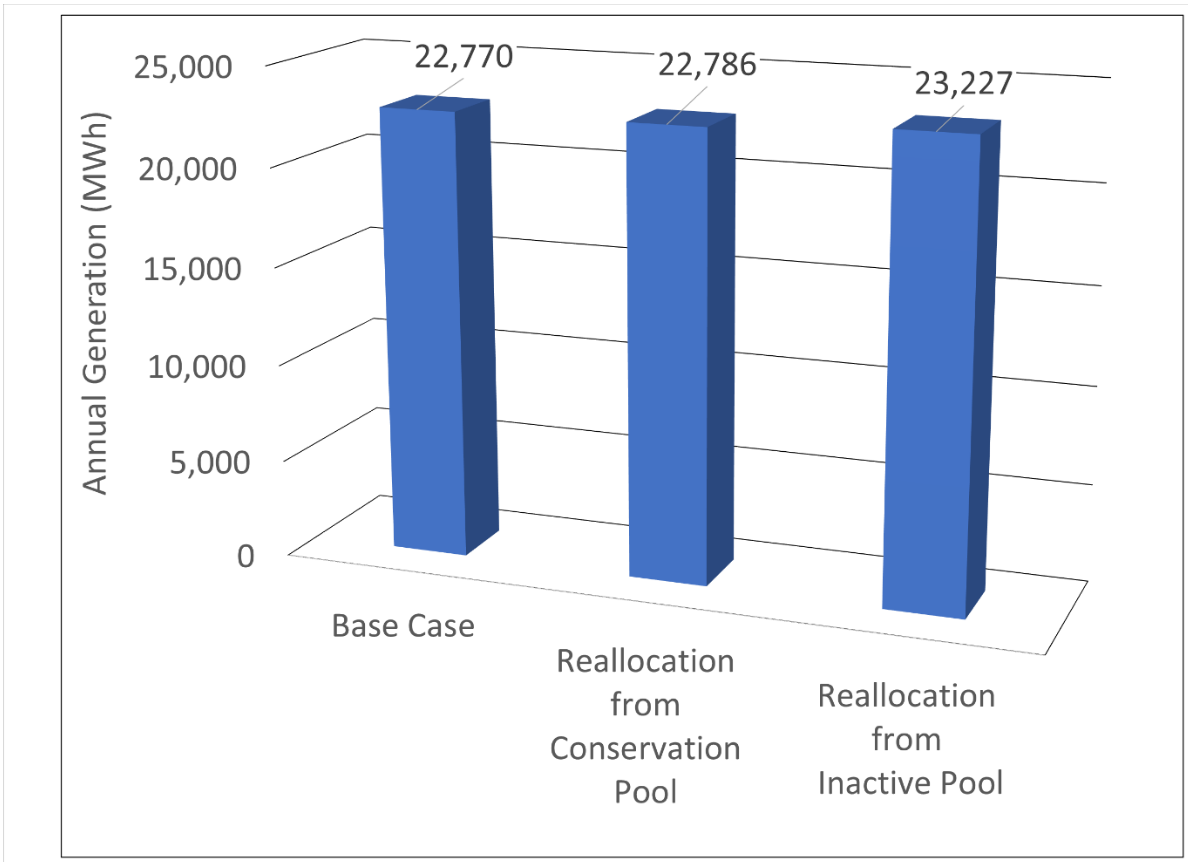

Figure 2-5. Average Annual Hydropower Generation by Alternatives

The value of the replacement energy has a seasonal trend following the demand and generating resource availability through the year. Therefore, in calculating annual value, it is necessary to look at how the generated energy varies monthly. Figure 2-6 shows both the average monthly energy generated for Base Case and other alternatives as well. Reallocation alternatives show a minor decrease in annual power generation only in the winter months compared to the Base Case.

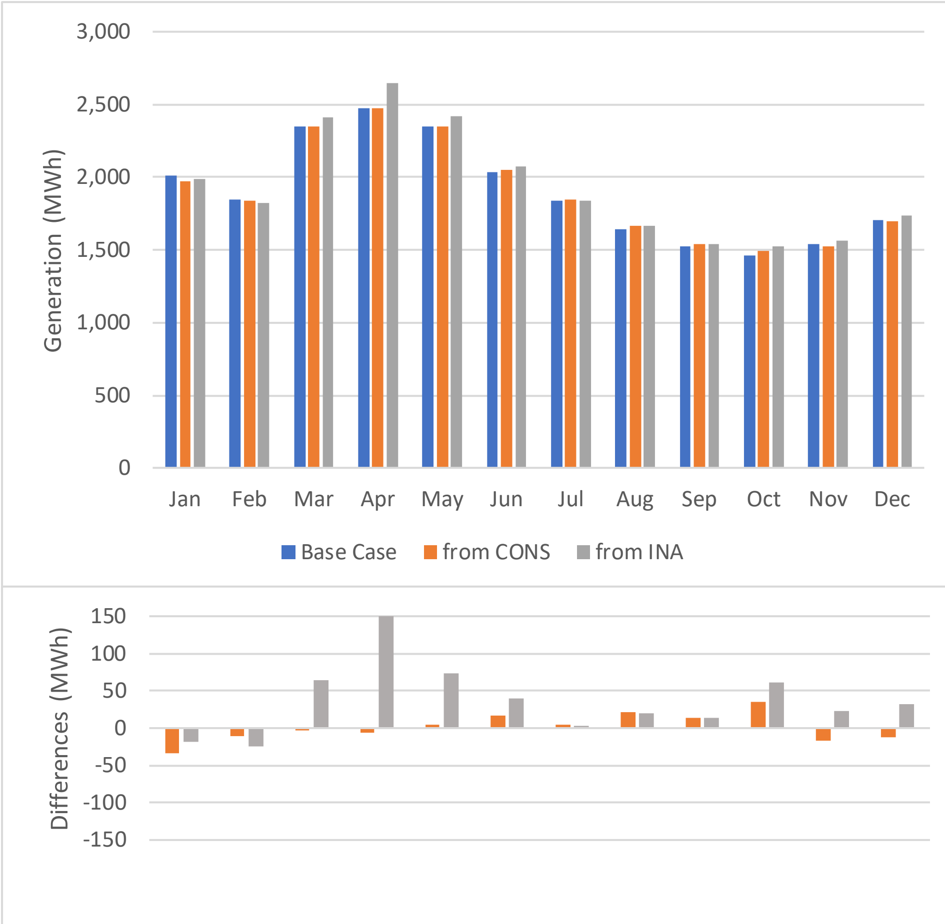

Figure 2-6. Monthly Generation for Alternatives to Base Case

3 Energy & Energy Value

Energy value is computed as the product of the energy loss in megawatt-hours and a block energy price ($/MWh). The block energy price is based on the cost of energy from regional combination of electricity generating plants that would replace the lost energy from the hydropower plant due to operational and/or structural changes.

3.1 Energy Blocks

3.1.1 Energy Blocks Defined

The energy prices used for this analysis reflect the daily differences in peak and off-peak operations, the seasonal dynamics related to demand and availability, and the annual forecasted changes due to modifications in capacity and overall demand. The following paragraphs describe the process of obtaining these values.

The regional definition of on-peak hours of generation is 6am to 10pm on weekdays. The off-peak hours of generation are the remaining hours on weekdays and all hours on weekends. However, because generation by Philpott hydropower plant is 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 3-1 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 3-1. Generation Block Schedule for SEPA/USACE Hydropower Plants

	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

3.1.2 Energy Allocation to Blocks

As an example of how daily energy production is allocated between on-peak and off-peak designations, Table 3-2 below shows the simulated daily energy production for Philpott Lake for the week of 7-Jan-2019, under the Base Case. Power plant generating capability is assumed constant, not varying with the rise and fall of the lake level. The average capability on Wednesday, 9-Jan-2019 was 15.2 MW and the Generation was 278.4 MWh. On-Peak generation for 16 hours could be 243.2 MWh, of which 11 hours would be SEPA contract generation (167.2 MWh) and the remaining 5 hours of On-Peak would be non-contract generation (76.0 MWh). Generation more than 16 hours on weekdays is off-peak energy (35.2 MWh). All power generated on the weekend is off-peak energy.

Table 3-2. On-Peak & Off-Peak Daily Blocks Energy Allocation for Philpott Lake – 7-Jan-2019 through 13-Jan-2019

DATE	Day	Capability (MW)	Energy Production (MWh)	Weekday			Weekend
				On-Peak Energy (contract) (MWh)	On-Peak Energy (non-contract) (MWh)	Off-Peak Energy (MWh)	Off-Peak Energy (MWh)
7-Jan-2019	Monday	15.2	198.7	167.2	31.5	0.0	0.0
8-Jan-2019	Tuesday	15.2	231.9	167.2	64.7	0.0	0.0
9-Jan-2019	Wednesday	15.2	278.4	167.2	76.0	35.2	0.0
10-Jan-2019	Thursday	15.2	263.2	167.2	76.0	20.0	0.0
11-Jan-2019	Friday	15.2	281.5	167.2	76.0	38.3	0.0
12-Jan-2019	Saturday	15.2	59.8	0.0	0.0	0.0	59.8
13-Jan-2019	Sunday	15.2	57.6	0.0	0.0	0.0	57.6

This energy block allocation procedure was applied to the HEC-RESSIM model output to transform daily energy production into energy blocks. Table 3-3 are the average annual energy blocks for the Base Case.

Table 3-3. Annual Average Monthly Energy Blocks for Philpott Lake under the Base Case

	On-Peak Hours (contract)	On-Peak Hours (non-contract)	Off-Peak Hours	Off-Peak Hours
	Weekday	Weekday	Weekday	Weekend
	MWH	MWH	MWH	MWH
Jan	1,693	105	40	170
Feb	1,562	85	34	168
Mar	2,016	139	38	156
Apr	1,665	672	47	92
May	1,677	436	9	223
Jun	1,636	231	4	161
Jul	1,526	81	7	224
Aug	1,428	74	2	138
Sep	1,241	154	24	104
Oct	1,253	40	11	156
Nov	1,243	40	5	253
Dec	1,478	49	14	164

3.2 Annual Energy of Alternatives

The Average Annual Energy (hydroelectric generation in MWH) in Table 3-4 and Table 3-5 have been summarized from the river basin operations simulation (model run output files) over the 60-year period of hydrologic record. As shown in Table 3-4 below the requested water supply from Philpott Lake causes very small changes in hydropower energy production.

Table 3-4. Philpott Annual Hydropower Plant Energy (MWh) Across *Water Supply Alternatives*

	Base Case	Reallocation from Conservation Pool		Reallocation from Inactive Pool	
Energy (MWh)	22,770	22,786		23,227	
Δ From Base Case	---	16	0.07%	457	2.01%

3.3 Energy Prices

Energy prices can significantly change hourly, daily, and seasonally. Therefore, to estimate lost hydropower energy value, the energy price forecast must consider the monthly, weekly, daily, hourly hydropower energy loss and the variability of the associated energy price.

3.3.1 Locational Marginal Pricing (LMP)

For this study we assume the energy prices for Philpott Lake are best estimated using hourly Locational Marginal Pricing (LMP) of the American Electric Power/Appalachian Power energy market hub reported in the Pennsylvania-New Jersey-Maryland (PJM)/Dominion sub-region.

LMP is a computational technique that determines an hourly shadow price for an additional megawatt-hour of demand. The Historical LMP values for the hub were downloaded from the PJM website.

Hourly LMP only provides historical pricing, so these data were utilized in combination with annual energy price forecast information from the Energy Information Administration (EIA) to develop a forecast for LMP.

3.3.2 Energy Price Forecast

The Energy Information Administration (EIA) publishes an Annual Energy Outlook (AEO) that includes thirty years of forecasted electricity costs for different electric market sub-regions organized by the three cost categories of generation, transmission, and distribution. The EIA forecast energy price of 'generation' is the representation of the value of the hydropower produced. The annual EIA 'generation' forecast for the PJM/Dominion sub-region of the electric market module (EMM) was used for the development of the LMP forecast values for this study.

The EIA forecast energy values encompass a wide range of assumptions, including a Reference Case that is used for calculating energy value in this study. The AEO forecast is initiated based on actual electricity prices for that year.

3.3.3 Shaping Ratio

The EIA forecast annual energy price is transformed to LMP energy price forecast using a shaping ratio. The shaping ratio is the LMP divided by the annual (historical) EIA 'generation' energy value. The EIA annual forecast value multiplied by the shaping ratio yields the LMP energy price forecast.

The shaping ratios are computed in the following procedure:

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

This can be rewritten as:

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

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

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

These shaping ratios are defined to reflect the daily and seasonal variability of the daily generation blocks in Table 3-1. To replicate this schedule, daily historical LMP values are sorted from high to low and divided into three blocks, with the highest LMP values associated with the on-peak weekday hours, and the lowest LMP values associated with the weekend off-peak hours. Seasonal variability is taken into account by computing shaping ratios for each month. These shaping ratios are computed as averages among days with like generation block (weekday/weekend) and months:

$$ShapingRatio(month, generation_{block}) = Average\left(\frac{LMP_{Past}(month, generation\_block, year)}{EIA\_Generation_{Past}(year)}\right)$$

This produces the following equation to estimate LMP forecasts for the daily energy blocks described in Table 3-6 for each month.

$$LMP_{Future}(generation\_block, month) = EIA\_Generation_{Future} \times ShapingRatio(generation\_block, month)$$

Hourly shaping ratios for each day are ranked and assigned to each block (formation of blocks is described in Paragraph 3.1 above) where the highest values are assigned to On-Peak Hours (contract).

Values assigned to each block are then averaged. Shaping ratios developed following this procedure are listed in Table 3-5.

Table 3-5. Shaping Factors

	On-Peak Hours (contract)	On-Peak Hours (non-contract)	Off-Peak Hours	
	Weekdays			Weekends
January	0.604720	0.479798	0.414703	0.442030
February	0.709737	0.548050	0.460123	0.478311
March	0.590488	0.466145	0.386267	0.444552
April	0.566245	0.479145	0.352264	0.403973
May	0.595758	0.472592	0.320515	0.384256
June	0.605849	0.435647	0.287918	0.378110
July	0.738110	0.493735	0.321427	0.427291
August	0.683072	0.468974	0.320685	0.409805
September	0.731972	0.487651	0.323151	0.404588
October	0.586126	0.473051	0.353637	0.463615
November	0.551909	0.451421	0.365630	0.417575
December	0.704275	0.560770	0.464199	0.536570

3.4 EIA Long Term Forecast

Figure 3-1 depicts the 2022 EIA reference case generation cost forecast for the PJM/Dominion sub-region. The average annual energy value based upon the EIA 30-year price forecast is amortized to a single number using the current federal discount rate of 2.5%.

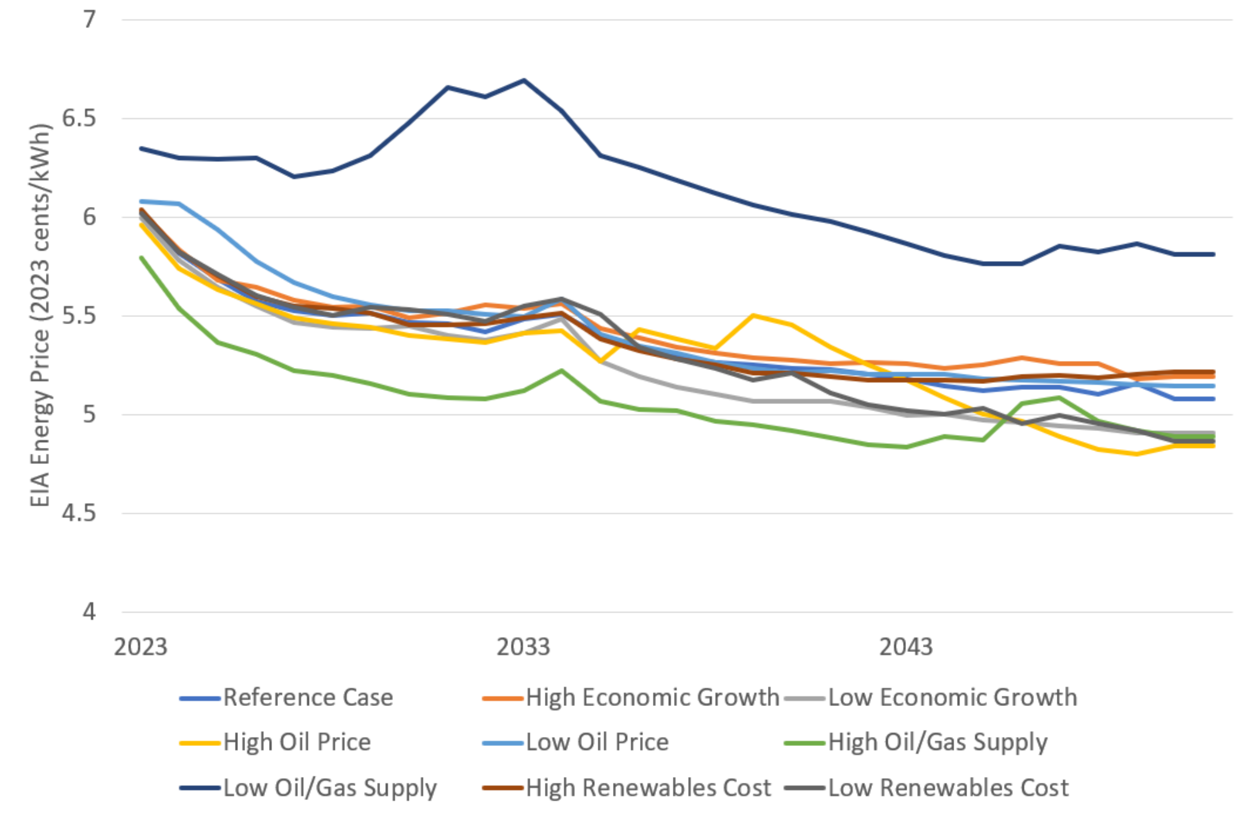

Figure 3-1. EIA Generation Price Forecast for PJM/Dominion Region

3.4.1 Energy Price Sensitivity

The 2022 EIA Energy Price Forecast includes scenarios that influence the Energy Price Forecast. These 2022 scenarios were amortized to show the possible range or variability due to several factors that influence 2022 EIA Energy Price forecast. Table 3-6 shows the possible magnitude of variability, or sensitivity in energy forecast values. The Reference Case is used for this study.

Table 3-6. Energy Price Sensitivity to 2022 Forecast Scenarios

EIA Price Forecast Scenarios	Annualized Energy Price (2023¢/kWh)	Difference from Reference Case
Reference case	$5.45	0.0%
High economic growth	$5.52	1.4%
Low economic growth	$5.32	-2.4%
High oil price	$5.34	-1.9%
Low oil price	$5.51	1.3%
High oil and gas supply	$5.18	-4.9%
Low oil and gas supply	$6.24	14.5%

3.4.2 Energy Prices - Reference Case

The amortized value (long-term) for the current 2022 EIA Reference Case of $54.45/MWh is then multiplied by the daily shaping factors for each generation block (weekday/weekend) for the daily energy prices (LMP) for each month. Table 3-7 summarizes these prices.

Table 3-7. Block Energy Prices ($2023/MWh)

Month	On-Peak Hours (contract)	On-Peak Hours (non-contract)	Off-Peak Hours	Off-Peak Hours
	Weekdays			Weekends
January	$32.93	$26.13	$22.58	$24.07
February	$38.65	$29.84	$25.06	$26.05
March	$32.15	$25.38	$21.03	$24.21
April	$30.83	$26.09	$19.18	$22.00
May	$32.44	$25.73	$17.45	$20.92
June	$32.99	$23.72	$15.68	$20.59
July	$40.19	$26.89	$17.50	$23.27
August	$37.20	$25.54	$17.46	$22.32
September	$39.86	$26.56	$17.60	$22.03
October	$31.92	$25.76	$19.26	$25.25
November	$30.05	$24.58	$19.91	$22.74
December	$38.35	$30.54	$25.28	$29.22

3.5 Energy Value

Although all plants in this system are defined as peaking plants, the actual hydropower operations of the individual power plants can vary significantly. For example, some plants may turn completely off and then back on again during peak demand periods, while others may have a minimum flow requirement that constantly generates a small amount of electricity with a maximum generation occurring during peak demand periods. Unfortunately, the detailed hourly generation information required from each plant to determine the daily peak and off-peak percentage of total generation is not available. To calculate the energy value, the method assumes that plants will operate to maximize the value of energy; that is, to generate the maximum amount of energy during periods of peak demand. Both the energy gained and value gained are quite small.

Table 3-8. Philpott Annual Hydropower Plant Energy Value (2023$) Across *Water Supply Alternatives*

	Base Case	**Reallocation from Conservation Pool**		**Reallocation from Inactive Pool**	
Energy Benefits (2023$)	$722,434	$746,761		$756,580	
Δ From Base Case	---	$1,153	0.15%	$10,972	1.47%

4 Capacity & Capacity Value

Capacity value is defined as the product of the change in dependable capacity and a capacity unit value, representing the capital cost of constructing replacement thermal generating plant capacity for the lost hydropower.

4.1 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.

4.1.1 Basis for Dependable Capacity Calculation Method

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.

This method is described in Section 6-7g of EM 1110-2-1701, Hydropower, dated 31 December 1985. Studies have shown that this method gives similar results to the more rigorous LOLP (Loss of Load Probability) studies.

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.

A long-term record of project operation must be used to evaluate the average dependable capacity for a project. Actual project operating records would be most desirable; however, certain factors may preclude the use of these records. The period of operation may not be long enough to give a statistically reliable value. Furthermore, operating changes may have occurred over the life of the project, which would make actual data somewhat inconsistent.

4.1.2 Dependable Capacity Calculation Procedure

The dependable capacity calculation procedure for Philpott Hydropower Plant 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 marketable capacity of 15 MW[1] based on the regional drought in 1981.

- The project's contribution of power is determined by first calculating each project's weekly average (generation) energy produced (MWh) for the peak demand months of mid-May through mid-September of 1981 (SEPA determined critical year) from the HEC-RESSIM model baseline run. Average weekly energy is characteristic the hourly-daily-weekly cyclical peak energy demand during the annual low water (hydropower)/high energy demand 4-month period.

- This number is then divided by SEPA's defined marketable capacity[1] (MW). This gives an estimate of the required/expected weekly hours (H) of generation in the peak demand period for the project.

- Next, the project's weekly average energy produced (MWh) during the peak demand months was calculated for each simulated year.

- Dividing this value by the project's required/expected weekly average hours (H) on peak determined in the previous step, yields an array of yearly supportable capacity values.

[1] Coordination with SEPA confirmed marketable capacity values for the Corps hydropower plants and the critical water year of 1981. SEPA's Marketable Capacity for Philpott is 15 MW

- The average across the array is the project's supportable capacity is the dependable capacity. (illustrated in Table 4-1)

Table 4-1. Dependable Capacity by the Average Availability Method (Base Case)

Year	Annual Critical Period			
	Average Weekly Energy (MWh)	Potential Supportable Capacity (MW)	Machine Capability (MW)	Actual Supportable Capacity (MW)
1960	447.89	29.64	15.200	15.200
1961	440.27	29.14	15.200	15.200
1962	395.26	26.16	15.200	15.200
1963	387.75	25.66	15.200	15.200
1964	369.52	24.46	15.200	15.200
1965	390.60	25.85	15.200	15.200
1966	391.19	25.89	15.200	15.200
1967	145.28	9.61	15.200	9.615
1968	266.76	17.65	15.200	15.200
1969	377.41	24.98	15.200	15.200
1970	388.19	25.69	15.200	15.200
1971	464.25	30.72	15.200	15.200
1972	695.65	46.04	15.200	15.200
1973	553.55	36.63	15.200	15.200
1974	471.74	31.22	15.200	15.200
1975	487.53	32.27	15.200	15.200
1976	440.61	29.16	15.200	15.200
1977	389.02	25.75	15.200	15.200
1978	559.59	37.03	15.200	15.200
1979	540.73	35.79	15.200	15.200
1980	496.36	32.85	15.200	15.200
1981	**226.68**	**15.00**	**15.200**	**15.002**
1982	387.51	25.65	15.200	15.200
1983	472.57	31.28	15.200	15.200
1984	478.11	31.64	15.200	15.200
1985	411.25	27.22	15.200	15.200
---	---	---	---	---
2017	499.38	33.05	15.200	15.200
2018	433.97	28.72	15.200	15.200
2019	507.02	33.56	15.200	15.200
			Dependable Capacity	14.847

4.1.3 Alternatives' Dependable Capacity

This process is repeated for Base Case and alternative water control operations using the HEC-RESSIM model runs. The average dependable capacity difference between the reservoir storage reallocation scenarios and Base Case is the small loss in dependable capacity caused by very small changes in reservoir storage reallocation. Results are shown in Table 4-2.

Table 4-2. Philpott Annual Hydropower Plant Dependable Capacity & Losses (MW) Across Water Supply Alternatives

	Base Case	Reallocation from Conservation Pool		Reallocation from Inactive Pool	
Dependable Capacity (MW)	14.847	14.798		14.793	
Δ From Base Case	---	-0.050	-0.34%	-0.055	-0.38%

4.2 Capacity Unit Value Calculation

Capacity unit values represent the capital cost and the fixed O&M cost of the most likely thermal generation alternative that would carry the same increment of load as the proposed hydropower project or modification. As discussed below in the screening curve analysis description, the cost effectiveness of the different thermal resources depends on how and when the resource is used. For example, coal fired plants may be used to replace a base loading hydropower plant while a natural gas fired turbine plant may be used to replace a peaking hydropower operation. A natural gas fired combined cycle plant would be used in an intermediate mode of load-following. In this section the process of determining the least costly, most likely combination of thermal generating resources, which would replace lost hydropower, is described. Also, the method calculating the capacity unit value is presented.

4.2.1 Typical Hourly System Generation

To establish the most likely thermal generation alternative, an analysis of how hydropower is currently dispatched/operated in the regional power system. The goal of this analysis is to show how much capacity can be defined as base load, how much can be defined as intermediate load, and how much can be defined as peaking. The process of computing a capacity value is done using plant hourly generation of a typical year or hourly average for the period of record.

Typical hourly generation for Philpott hydropower plant was then divided by plant nameplate capacity. This allows for an exceedance curve for percent of plant nameplate capacity. (Figure 4-1).

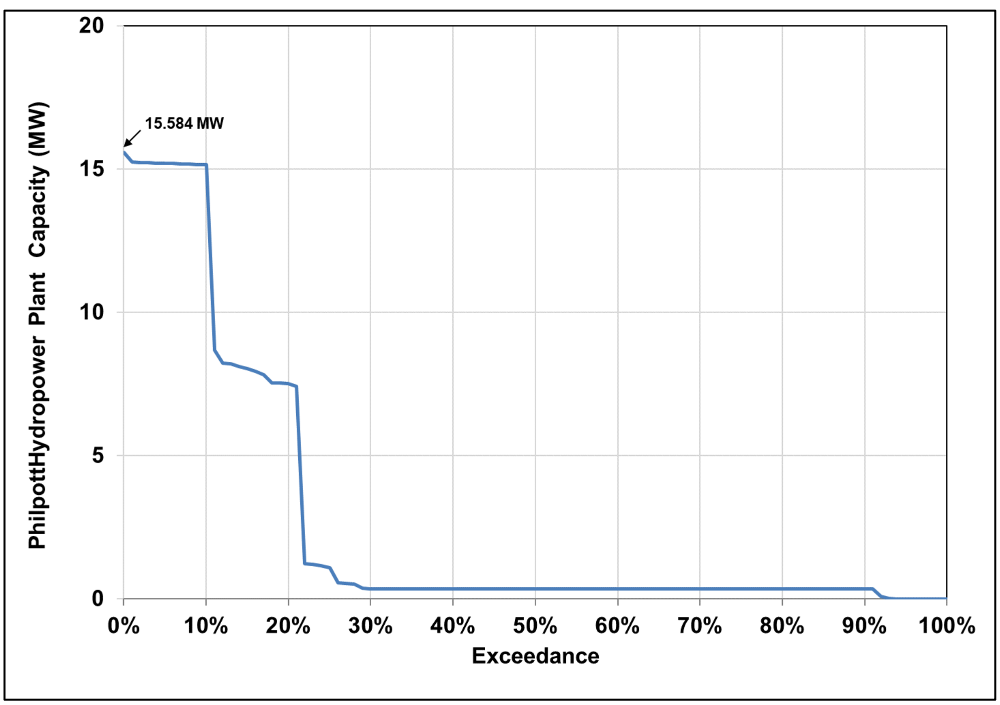

Figure 4-1. Percent of Philpott hydropower plant nameplate capacity exceedance chart

4.2.2 Screening Curve Analysis

A screening curve is a plot of annual total plant costs for a thermal generating plant (fixed capacity cost plus variable operating cost versus annual plant factor (PF). 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.

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)

4.2.2.1 Plant Capacity Cost

Plant capacity cost for coal-fired steam, natural gas-fired combined cycle and natural gas-fired combustion turbine plants were computed using data from the EIA. Capacity values were computed for the PJM/Dominion region based on a 2.5% interest rate and 2023 price levels. Adjusted capacity values are shown in Table 4-3. The adjusted capacity values incorporate adjustments to account for differences in reliability and operating flexibility between hydropower and thermal generating power plants. See EM 1110-2-1701, Hydropower, Section 9-5c for further discussion of the capacity value adjustments.

4.2.2.2 Plant Operating Costs

Operating costs for coal-fired steam, gas-fired combined cycle and gas-fired combustion turbine plants were developed using information obtained from the publication *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies (2020)* and other sources. The information obtained included fuel costs, heat rates and fixed and variable operations and maintenance costs. The resulting values are shown in Table 4-4.

Table 4-3. Adjusted Capacity and Operating Costs for PJM/Dominion Region in 2023$

State	Coal-fired (CO) Steam Plant		Natural Gas-fired Combined Cycle (CC) Plant		Natural Gas-fired Turbine (CT) Plant	
	Capacity	**Energy**	**Capacity**	**Energy**	**Capacity**	**Energy**
	$/KW-yr	$/MWh	$/KW-yr	$/MWh	$/KW-yr	$/MWh
Estimate	$380.26	$31.46	$101.72	$39.74	$88.69	$60.53

4.2.2.3 Screening Curve

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. The plots are shown in the lower portion of Figure 4-3.

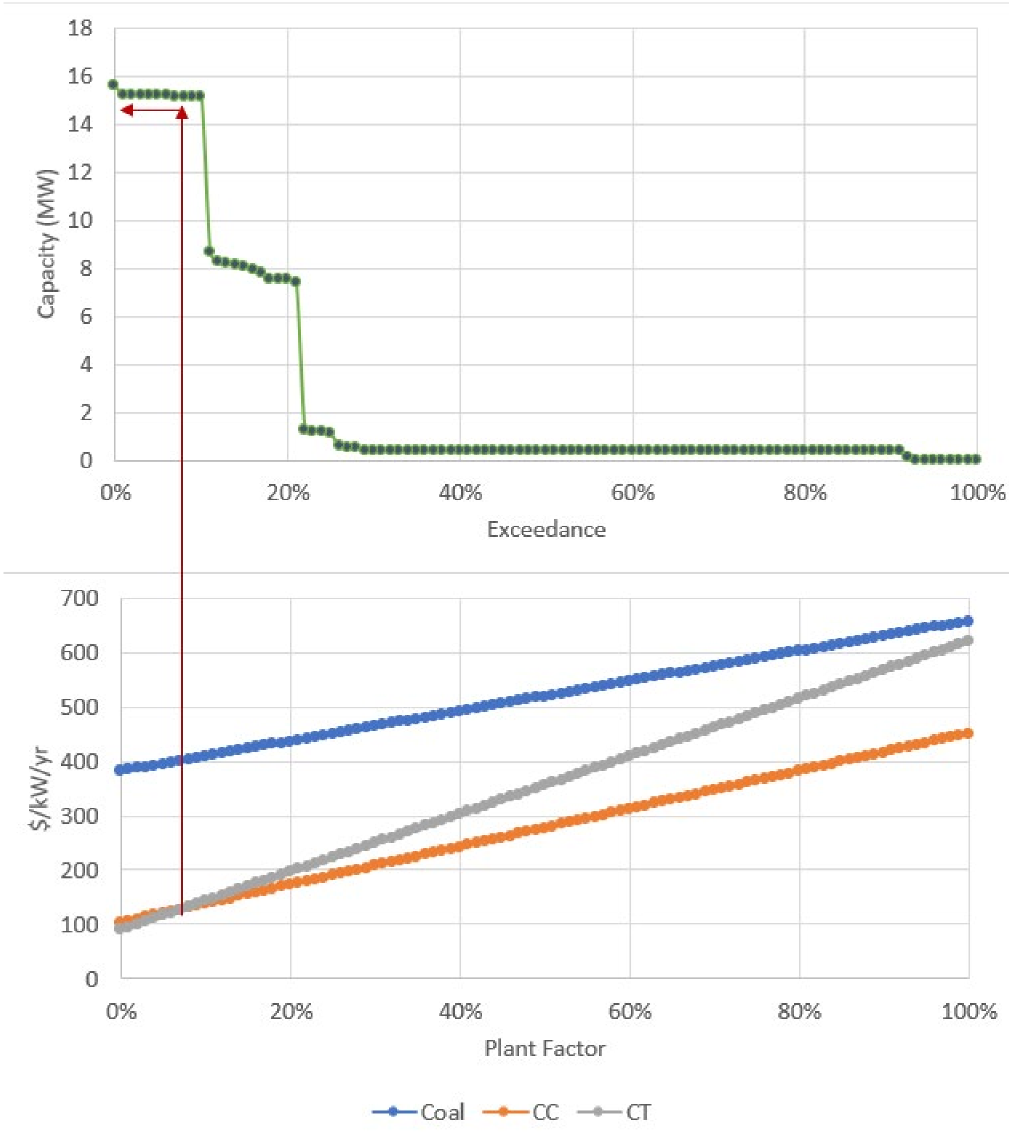

Figure 4-2. Screening Curve for Thermal Generating Plant Types in the PJM/Dominion Region

4.2.2.4 Interpretation

The Screening Curve shows that the natural gas-fired combustion turbine plant type is the least expensive for plants operating less than 7.2% of the time, while for plants operating more of the time the natural gas-fire combined cycle plant is the least expensive. The maximum system operating capacity is shown as 15.584 MW, of that total system capacity up to 0.406 MW would operate less than 7.2% of time and the least cost operation plant type would be natural gas-fired combustion turbine plant type. The remaining system capacity of 15.02 MW runs more than 7.2% of time and the least cost thermal generating plant type would be the natural gas-fired combined cycle plant type.

The most likely least cost combination of thermal generating plant types that could be used to replace Philpott hydropower would be 0.406 MW of natural gas-fired combustion turbine plant type and 15.178 MW of natural gas-fired combined cycle plant type.

4.2.3 Composite Capacity Unit Value

The process for calculating the composite unit capacity value is described by the following algorithm.

- From the screening curve, determine the “breakpoints” (the plant factors at which the least cost plant type changes).
- 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 that would be carried by each thermal generation plant type.
- Calculate percent of total generating capacity for each thermal alternative using the portions defined in the prior step above.
- Calculate the composite unit capacity of the system as an average of each the thermal alternative’s capacity cost weighted by their percent of total generating capacity defined in the prior step.

The annual composite unit capacity value is developed following the calculation procedure in Table 4-9.

Table 4-4. Annual Composite Unit Capacity Value Calculation

Plant Type	Capacity (MW)	Proportion (%)	Plant Type Cost ($/kW-yr)	Proportion of Cost ($/kW-yr)
NG Combined Cycle Turbine	15.178	97.4%	$101.72	$99.07
NG Combustion Turbine	0.406	2.6%	$88.69	$2.31
Coal	0	0	$380.26	$0.00
Total	15.58	100%	n/a	**$101.38**

Estimated annual thermal replacement generating capacity value is $101.38/kW-yr.

The value of capacity for each alternative is determined by multiplying the dependable capacity for each alternative in Tables 4-2 by the composite unit capacity value in Table 4-4. The value of the small loss of capacity under each alternative is listed in Table 4-5 below.

Table 4-5. Value of Philpott Annual Hydropower Plant Dependable Capacity ($) Across Water Supply Alternatives

	Base Case	**Reallocation from Conservation Pool**		**Reallocation from Inactive Pool**	
Capacity Benefits (2023$)	$1,505,234	$1,500,215		$1,499,673	
Δ From Base Case	---	-$5,019	-0.33%	-$5,561	-0.37%

5 Hydropower Benefits Foregone

The following table presents a summary of the total hydropower value for the alternatives of this Philpott Reallocation Study. Hydropower Value is the sum of energy value and capacity value. For the small amount of reservoir storage reallocated from the Conservation Pool there will be a very small annual hydropower value loss of -$3,866 (or -0.17%). This very small reservoir storage reallocated from the Inactive Pool could result in a very small gain in hydropower value of $5,411 (or 0.24%).

Table 5-1. Value of Philpott Plant's Total Hydropower (energy + capacity) Across Water Supply Alternatives

	Base Case	**Reallocation from Conservation Pool**		**Reallocation from Inactive Pool**	
Hydropower Benefits (2023$)	$2,250,842	$2,246,976		$2,256,253	
Δ From Base Case	---	-$3,866	-0.17%	$5,411	0.24%

6 Revenues 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."[2]

"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. …"[3]

Revenue foregone is to be based on the current SEPA contract Rates applicable to power generation by the Ker-Philpott plants. The current rates are:

Energy Rate Total:	\$17.80/MWh
Monthly Capacity Charge:	\$4.40/kW-month (\$52,800/MW-year)

To compute energy revenues foregone, the contract energy rate is applied to the average annual contract energy foregone, and the capacity charge is applied to foregone dependable capacity. The tables below show the Power Revenue Foregone for each of the alternatives.

[2] 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.

[3] 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 6-1. Annual Revenue Summary Across Water Supply Alternatives

Alternative	Energy (MWh)	SEPA Energy Rate ($/MWh)	Dependable Capacity (MW)	SEPA Capacity Rate ($MW-year)	Revenue ($)	Revenue (foregone) ($)	
Base Case	22,770	$17.80	14.847	$52,800	$1,189,246	---	
Reallocation from Conservation Pool	22,786	$17.80	14.798	$52,800	$1,186,919	($2,327)	-0.20%
Reallocation from Inactive Pool	23,227	$17.80	14.793	$52,800	$1,194,477	$5,231	0.44%

7 PMA Credits

7.1 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 the storage is reallocated from hydropower to water supply, 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.

7.2 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 between an Alternative and a Base Case multiplied by the SEPA Composite Revenue Rate. Additional credit will be based on revenue actually lost or replacement costs actually incurred.