Appendix F: Methods for Estimating the Impacts of HFEs on Hydropower at Glen Canyon Dam

Assumptions and Methodologies:

The implementation of an HFE requires that water released through Glen Canyon Dam (GCD) be redistributed from when it would have been released in the no action case to another month, day or hour to produce the desired HFE. While most of the water that is redistributed to implement an HFE is released through the powerplant, some of the redistributed water bypasses the powerplant. The primary economic impact of an HFE comes from this redistribution of water.

The amount of water redistributed to implement an HFE varies significantly from one HFE to another. Table 1 below provides a summary of the water used in each of the 13 HFEs.

Table 1
Water Volume Required for Each of 13 HFEs

	HFE Total (af)	Bypass (af)
HFE#1	344,628	100,413
HFE#2	271,240	76,612
HFE#3	234,545	64,711
HFE#4	197,851	52,810
HFE#5	161,157	40,909
HFE#6	124,463	29,008
HFE#7	87,769	17,107
HFE#8	54,132	6,198
HFE#9	44,215	3,182
HFE#10	37,025	1,488
HFE#11	32,810	744
HFE#12	26,653	83
HFE#13	21,157	0

Description of Analysis Method[5]: Computing Energy and Capacity Prices
ENERGY: Electricity is unique among energy sources in that it must be produced at the same instant that it is needed by customers. Storing electricity on a utility scale is difficult

[5] The analysis for this EA was completed by Western Area Power Administration, CRSP Management Center in Salt Lake City.

and costly, and so it is not done except in a few special circumstances. Since electricity cannot be stored easily like other energy sources such as oil or natural gas, *when* electricity is generated has a large effect on how valuable it is to customers, and the price utilities are willing to pay for it. Electricity generated in the middle of the night, or on a Sunday, or in the month of October or April is worth less because people use less electricity at those times. Conversely, electricity generated at noon on a weekday, and in a month such as July or August is worth a lot more because people and businesses are using a lot of electricity during those times. When Western analyzes what a particular change in the operations of a hydroelectric powerplant such as GCD costs, the overriding factor in determining the value is changes to, or restrictions to, *when* the power is generated.

An important step in calculating the cost of HFEs is deciding what price of electrical power (capacity and energy) should used in the analysis by determining how much the electricity that is being produced will cost the customers. For this analysis, electricity futures prices were used for pricing electrical energy. Futures prices are commercially available projections of the price electric energy will sell for during a particular period of time in the future, delivered at a particular location on the electrical grid.

Energy futures prices are widely used in the electrical utility industry for buying and selling energy to be delivered at a future date. Futures prices are quoted as a standard product for either on-peak periods (Monday through Saturday, 16 daytime hours) or off-peak periods (8 nighttime hours, plus all day Sunday). Bulk purchases and sales of electrical energy are commonly made in quantities of megawatt hours (one megawatt hour is equal to 1,000 kilowatt hours), and are priced in dollars per megawatt hour, abbreviated $/MWh. The price is quoted at a particular location on the electrical transmission system (“trading hub”), usually a location where many buyers and sellers of electricity have access.

One such location is the Palo Verde Nuclear Generating Station, about 50 miles west of Phoenix, Arizona. Western’s CRSP Management Center has access to this trading hub and often buys energy there to supplement its deliveries of Federal hydropower to its customers. Because of their widespread use in the western United States power markets, Palo Verde futures prices were used in this analysis. It is important to note that unlike energy, capacity generally cannot be purchased at these trading hubs.

The GTMax model that Western uses to analyze and plan its operations is programmed to have Glen Canyon powerplant generate as much electrical energy and capacity as possible (within operating constraints) during the hours when prices input into the model are highest. The model is designed to maximize the value of the energy produced by releasing water through powerplant turbines at the dam that spin generators to produce electricity. One of the inputs to the model is a set of energy prices that are more expensive during high-load hours relative to prices during low-load hours. Prices follow a pattern that is similar to Western’s customers’ loads. When the load increases during a low load hour by a small amount, for example one MW, the corresponding increase in price is relatively small. On the other hand, during times of high demand, the same one-MW increase in load will result in a much larger price increase. Therefore, although prices and loads have the same general pattern, the price pattern over time tends to be comparatively flat at night while exhibiting a relatively higher spike during the peak load hours.

The following are steps Western took to prepare energy price data for input into the GTMax model:

On and off-peak futures prices at Palo Verde on April 11, 2011, were obtained from IVG Energy[6]. Western decided for the purposes of this analysis to use a price level of 2016, or halfway through the 10-year analysis period.

IVG futures prices for the year 2016 are specified monthly. To update these prices it was necessary to scale the April 11, 2011, Palo Verde futures prices using a scaling factor. The futures price for natural gas was selected for scaling since natural gas futures prices[7] are available for many years into the future and are available for the past. Also, fuel prices typically account for about 90% of the cost of electricity generation and therefore, there is a close correlation between the price of natural gas and the market price of electricity.
Using the NYMEX gas futures price for April 11, 2011, monthly prices were scaled by about 4.0 to 4.5 percent depending on the month.

Finally, the 2016 monthly on-peak and off-peak prices were increased or decreased from the base value based on historical Western customer loads for that hour. This creates a series of power prices that are scaled to resemble the way that customers typically schedule their power allocations from Western. In that way, power prices enable the GTMax model to allocate more available water for power generation during those hours when it has the highest value to customers, and less water in those hours when it is less valuable. The result of the above approach is a set of 168 hourly prices (one week long) for each of 12 months of the year at a 2016 price level. That information was then loaded into the GTMax model.

Table 2 documents the on-peak and off-peak energy futures prices by month that were used to scale to hourly prices.

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6 IVG Energy http://www.ivgenergy.com/ provides subscribers with news, information, and power prices that are updated daily.
7 Information on natural gas futures prices was obtained from the CME Group website: http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html

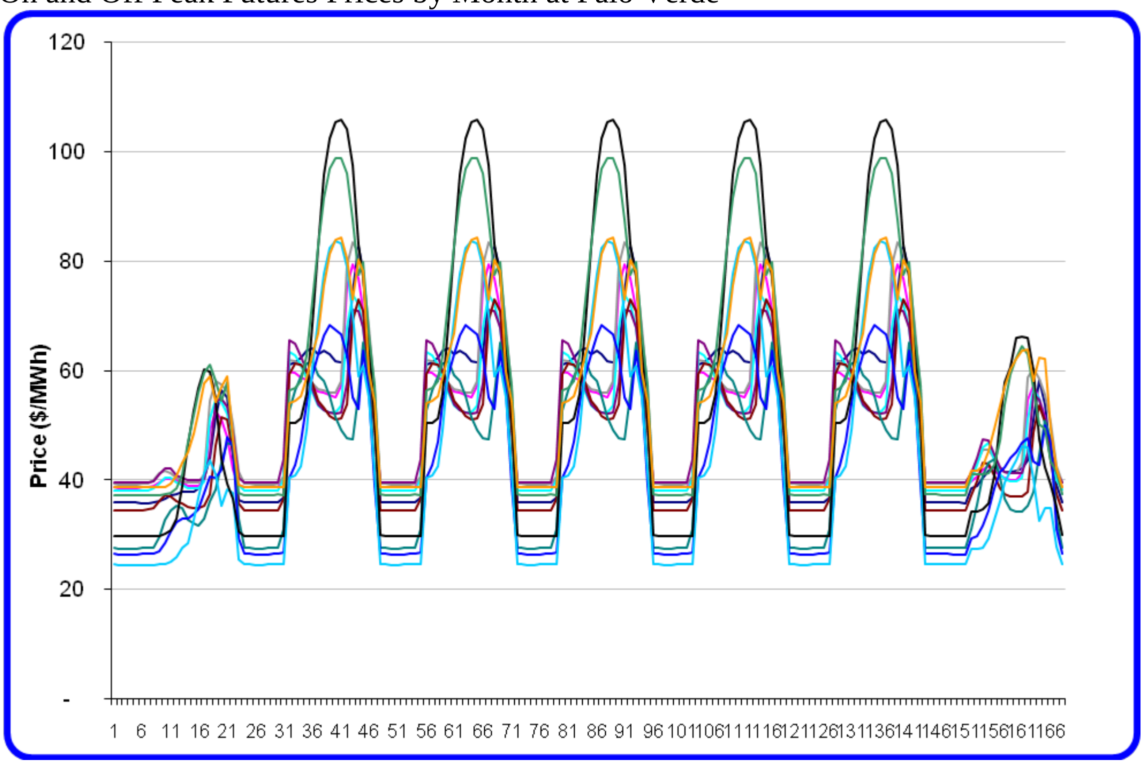
Table 2

2016 On and Off Peak Energy Futures Prices by Month at Palo Verde

	On-Peak Scaled		Off-Peak Scaled	
Jan	$	57.31	$	39.35
Feb	$	57.04	$	40.79
Mar	$	54.97	$	36.53
Apr	$	51.77	$	30.36
May	$	53.16	$	29.35
Jun	$	56.87	$	27.43
Jul	$	71.78	$	34.12
Aug	$	71.82	$	41.01
Sep	$	65.52	$	41.73
Oct	$	60.49	$	38.43
Nov	$	58.99	$	39.57
Dec	$	61.53	$	40.65
Ave	$	60.10	$	36.61

Figure 1 shows the results of this scaling process in $/MWH for a typical week (Sunday through Saturday).

On and Off Peak Futures Prices by Month at Palo Verde



Hours of the Week

The prices shown in Figure 1 were used by GTMax for each of the 10-years of the study period.

CAPACITY: Electrical capacity is defined as the maximum amount of generation that is available from a powerplant at any given period of time. Electrical capacity is important because it is necessary for the power system to have sufficient capacity to meet the peak demand, or the result will be problems such as blackouts and brownouts. The changes in operations at GCD from HFEs not only reduce energy production but also reduce the electrical capacity produced by the plant. In addition to the cost of purchasing electrical energy, there is also a cost for electrical capacity. Capacity costs are more related to the cost of constructing a powerplant, while energy costs are more related to the cost of operating and maintaining the powerplant. Because of this distinction, energy costs tend to change more often, owing to changes in the cost of fuel and personnel, while the cost of electrical capacity tends to remain more constant. Electrical capacity is often specified and priced as a separate product from electrical energy in bulk power purchase and sale transactions. Western, for example, has an energy price and a capacity price as components of its rate for power sales to customers. For this analysis, a price of $106.70/kW-year, or about $8.90/kW-month for any changes to capacity has been used. The capacity cost is based on an Advance Combustion Turbine 2011 construction cost.

Under some conditions, an electrical generator must be constructed to replace lost GCD generation as a result of an HFE or series of HFEs. Some uncertainties that must be considered include:

The HFE protocol is proposed as 10-year action. HFEs would be scheduled for October-November and/or March-April. This means water may be added to these months from other months in the year. If implementing the protocol results in a reduction by Western of a capacity commitment to GCD electrical contractors, those contractors will need to add capacity resources as a result.

While Western's contracts for Federal hydropower are based on the capacity of the powerplant and the average electrical energy produced, Western often purchases small amounts of energy from electrical energy exchanges to meet its hourly contractual commitments. When capacity is in short supply in the region in which Western purchases power, or when transmission constraints require additional purchases, the prices Western pays for electrical energy include a capacity premium.

Western's power customers are uncertain as to the stability and availability of the GCD resource under their long-term purchase contracts. Since the planning horizon for the construction of new electrical generators is long (10-20 years), utilities that have contracts for Federal power from the Colorado River Storage Project (CRSP) dams may "overbuild" when they undertake new generating capacity construction due to the uncertainty of the GCD resource.

This analysis did not attempt to measure whether new capacity would need to be constructed to replace capacity lost as a result of the HFE protocol. Instead, the difference in available capacity between the No Action and the Proposed Action case for the peak month for each of the hydrologic and sediment cases has been calculated. Having identified those capacity losses, a capacity cost has been applied based on the annualized construction costs of an electrical generator that would be a likely replacement for GCD power.

THE MODELING: Monthly GCD Release Volumes for the No Action and Proposed Action Alternatives

Reclamation used its Riverware reservoir operations model to develop the GCD monthly water release volumes used in this analysis. Twelve 10-year periods of 120 monthly releases, were developed to include all the potential conditions that Reclamation wanted to study. A hydrological condition, with a sand condition, over a 10-year period, is called a trace. Of the 12 traces, three are base case or No Action Alternatives for dry, median, and wet hydrological conditions. These do not have any HFE releases included. The remaining nine traces include three change cases or Proposed Action Alternative traces for dry, median, and wet hydrological conditions. These have HFE releases. Western's GTMax analysis modeled each of the 12 traces for the entire 10-year period.

Monthly Lake Powell Elevations

The three No Action Alternative traces provided by Reclamation included the Lake Powell reservoir elevation associated with each monthly release volume from GCD. The nine Proposed Action Alternative traces provided by Reclamation did not include Lake Powell elevations. Lake elevation is used by the GTMax model in its computations to determine the efficiency at which the hydroelectric generators convert water releases through turbines into electrical power. It was therefore necessary to compute lake elevations associated with each of the 12 traces, not just the three base case traces[8]. Calculations of reservoir elevations are based on an equation that estimates elevations based on the amount of water it holds.

HFE Hourly Release Profiles

For each of the 13 HFEs Reclamation included in the EA, an hourly release profile was constructed in an Excel spreadsheet. Each HFE includes hourly releases in cubic feet per second (cfs) and acre-feet for the entire month in which the HFE occurs. According to the proposed HFE experimental protocol, HFEs would only occur in March-April or October-November.

[8] Calculation method for lake elevations for the Proposed Action traces: 1. Using an equation that relates the water storage volume in Lake Powell to the lake elevation, the base case elevations were converted to equivalent water volumes. 2. For each change case trace associated with that base case trace, the volume of water was increased or decreased each month by that amount that the change case releases differed from the base case releases, resulting in an adjusted storage volume for each month of the change case trace. 3. Using the same equation as in step one above, the adjusted storage volumes for the change cases were converted back to lake elevations, yielding a lake elevation value corresponding to the water releases in each change case trace.

The water release in the HFE month was broken down into three parts:

A base flow release amount was calculated for the month, consisting of a minimum release from GCD of 5,000 cfs during the 7 pm to 7 am period, and 8,000 cfs during the 7 am to 7 pm period, each day. Cfs values were converted to acre-feet per hour.

The hourly ramp up (4,000 cfs) period, peak flow period, and hourly ramp down (1,500 cfs) period were then added to the base flow amount. The above release constraints are defined in the GCD Record of Decision (ROD) and are used in the GTMax modeling calculations.

The maximum water release through the powerplant is dependent on a number of factors including the number of turbines in operation, turbine maximum generation capability, and the reservoir forebay elevation. Any water releases during the HFE in excess of the maximum level were assumed to bypass the powerplant. The hourly releases during experimental hours were summed so that, for each of the 13 HFEs, there is a base flow release through the powerplant, an HFE release through the powerplant, and a bypassed water release, all in acre feet. Knowing the amount of water released each hour of the HFE enables calculation of each hour's energy generation in MWh and so enables the calculation of the total dollar cost of the generation based on the prices described above.

Adjusting Monthly Releases

The monthly release values from the Riverware model that Reclamation provided for each of the 12 traces is a total release volume that includes the base flow release volume and HFE release volume. For the GTMax modeling process, it is necessary to remove the HFE release volumes from the total release volume to leave only the base flow release volumes in those months where an HFE was scheduled. The entire release during the days when the HFE test occurred was removed from the total (using the same method described in the paragraph above), and the remaining water volume was used to compute the actual base flow release for the month. This actual base flow was used by the GTMax model for computations.

Running Typical Weeks in GTMax
Having adjusted base flow quantities enabled the GTMax program to pattern the water over the typical week restricted by GCD ROD powerplant constraints. GTMax patterns the generation releases that result in the greatest possible value of the resulting hydropower generation in dollars, using the energy prices described previously.

The results from the typical week are then scaled up by the model to become monthly values. The output of the GTMax run is the value of the generation in each month excluding the value of the generation associated with an HFE. To get the complete result, the dollar value of the base flow generation is then added to the value of the generation associated with the HFE water releases described in the section above.