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WESTERN WIND AND SOLAR INTEGRATION STUDY HYDROPOWER ANAYSIS: BENEFITS OF HYDROPOWER IN LARGE-SCALE INTEGRATION OF RENEWABLES IN THE WESTERN UNITED STATES

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ABSTRACT

NREL and research partner GE are conducting the Western Wind and Solar Integration Study (WWSIS) in order to provide insight into the costs and operational impacts caused by the variability and uncertainty of wind, photovoltaic, and concentrated solar power employed to serve up to 35% of the load energy in the WestConnect region (Arizona, Colorado, Nevada, New Mexico, and Wyoming). The heart of the WWSIS is an hourly cost production simulation of the balancing areas in the study footprint using GE's Multi-Area Production Simulation Model (MAPS). The estimated 2017 load being served is 60 GW, with up to 30 GW of wind power and 4 GW of existing hydropower. Because hydropower generators are inherently flexible and often combined with reservoir storage, they play an important role in balancing load with generation. However, these hydropower facilities serve multiple higher priority functions that constrain their use for system balancing. Through a series of comparisons of the MAPS simulations, it was possible to deduce the value of hydropower as an essential balancing resource. Several case comparisons were performed demonstrating the potential benefits of hydro and to ascertain if the modeled data was within the defined hydro parameters and constraints. The results, methodologies, and conclusions of these comparisons are discussed, including how the hydro system is affected by the wind power for different wind forecasts and penetration levels, identifying the magnitude and character of change in generation pattern at each of the selected hydro facilities. Results from this study will focus on the appropriate benefits that hydropower can provide as a balancing resource including adding value to wind and solar and reducing system operating costs to nearly one billion dollars when offsetting more expensive generation systems as large penetration levels of renewable, especially wind power, are introduced to the grid system.

Key Words: Hydropower, Wind Integration, System Modeling.

INTRODUCTION

The North American Electric Reliability Council (NERC) develops and enforces reliability standards for entities that are engaged in ownership, usage, and operation of the bulk power system. NERC is a non-profit voluntary organization whose goal is to ensure a reliable, adequate and secure electric system. NERC is made up eight regional reliability council members. These members include: investor-owned utilities, federal power agencies, independent power producers, power marketers, rural electric cooperatives, and state, municipal and provincial utilities. There are a total of 133 control areas within these regions. Control areas are defined as sub-regions of the electrical grid that are responsible for meeting the reliability standards set by NERC and ensuring there is sufficient generation capacity to meet the load demand within the area. A primary challenge in operating a control area is to ensure there is adequate capacity to meet the daily load requirements plus additional reliability reserves and to ensure there is adequate flexible generation on-line that is able to cover the variation in the load that occurs on time scales from nearly instantaneous to hours ahead. The second-to-second fluctuations in load must be met by agile generators outfitted with automatic generation controls (AGC) and is frequently referred to as regulation. Gas turbines or hydropower units are capable of meeting regulation requirements. The minute to hour variations are met by quick response units and is defined as load following. Serving the daily load demand requires scheduling units the day before operation, including both the agile generators that move with the load and the base load resources that do not vary substantially, such as coal or nuclear powered steam plants. The process of scheduling these units, and the costs incurred due to imperfect forecasting is termed unit commitment. The phrase “ancillary services” is used to describe the services needed to meet these day after day fluctuations in load [1].

As the current trend in generation expansion is to meet larger and larger amounts of the demand load with clean, reliable and affordable energy sources, renewable energy systems such as wind and solar become increasingly practicable. On the other hand, these resources are inherently variable dictated by the changing state of the wind and solar resources. In the case of wind and solar photovoltaics (PV), none of which have intrinsic storage capabilities, electricity cannot be efficiently stored on a large scale using currently available technology; it must be used as it is produced. Consequently, when a change in demand or generation occurs, such as due to the variability in power output from a wind plant, somewhere in the interconnected power system the production or consumption of electricity should make a corresponding change. Thus the variability and lack of storage often results in increased costs ensuing from an increased use of ancillary services to maintain system reliability. One solution to solve the lack of storage and address renewable energy variability issues is to couple the system with a clean, responsive generation source such as hydropower. Hydropower, as an agile generation source able to respond to rapid fluctuations in demand, and with some built-in energy storage in the form of hydro impoundment, has long been a valuable resource in electrical system balancing. Peaking hydro plants like that of Hoover Dam often have a significant water storage capability and are designed to rapidly change output levels in order to satisfy changes in demand for electricity. However, hydro facilities also serve many functions beyond power generation, and these other functions typically are of higher priority such as: water use priorities including irrigation, flood control, navigation, fish habitat, recreation and energy production. These higher priority functions of the dam often limit the true capability of performance of the dam. Such is the case of Glen Canyon Dam where it is operated under the Glen Canyon Dam Final Environmental Impact Statement and Record of Decision [2]. This limits the maximum and minimum generation and flow through the turbines along with limiting the up and down ramps during certain periods. As the price of renewables decline, the feasibility of large-scale wind becomes more practicable. As larger amounts of renewables enter the electrical system, integration studies become necessary to determine the operational impacts and costs caused by the variability and uncertainty inherent in wind and solar. The purpose of this study is to examine the impact of hydro power as a balancing resource in the Western Wind and Solar Integration Study. The objectives of this study include investigating the change in hydro generation at two of the largest hydro facilities located in the study footprint and to investigate the aggregated hydro use in the WECC, deducing the value of hydro power using different several hydro schedules.

WESTERN WIND AND SOLAR INTEGRATION STUDY

The National Renewable Energy Laboratory (NREL) and research partner GE have conducted the Western Wind and Solar Integration Study (WWSIS) in order to provide insight into the costs and operational impacts caused by the variability and uncertainty of wind, photovoltaic, and concentrated solar power employed to serve up to 35% of the load energy in the WestConnect region (Arizona, Colorado, Nevada, New Mexico, and Wyoming), see Figure 1 for study footprint. Note the study footprint is located entirely within the WECC (Western Electricity Coordinating Council) region, located on the left side of Figure 1. The WECC represents one of three interconnected electrical systems in the NERC regions, and therefore it was necessary to model the entire WECC region in order to correctly model the balancing areas in the WWSIS footprint. Using historical load and weather patterns from years 2004, 2005, and 2006, the study examined the details of system operation and dispatch though an hourly cost production model for each historical year with loads scaled to that expected in the study year of 2017. Because the wind and solar power production is directly related to the weather, and because the load and weather are implicitly correlated, in order to preserve any correlation that exists between the wind and solar production and load, it is important to utilize wind and solar power production estimates that are based upon the weather patterns that were present in the load years of 2004, 2005 and 2006.

Figure 1: WestConnect Footprint as used in the WWSIS. Source:http://wind.nrel.gov/public/WWIS/MilliganWWSISSWAT.pdf

Lack of high quality wind data that is synchronized with the region's electric load becomes one of the primary obstacles in conducting wind integration studies. Time series data must be used to perform power system analysis for system's with significant wind penetration levels. Data can be obtained in several ways with on-site observations of power generation being the most desirable, but due to the fact that this data can only be obtained from limited existing projects, this restricts its use in large-scale integration projects. As a practical alternate to actual field data, numerical weather prediction (NWP) models can be used to simulated climatological conditions over fairly broad, selected regions. These simulations are driven by solution of the basic conservation equations that model the physical interactions in the atmosphere. The NWP models employ the reanalysis of wind speed datasets (spatially and temporally coarse global datasets) to determine boundary conditions for a model run, which is then downscaled using a mesoscale (i.e. regional) model that can produce a finer physical resolution, down to about 1-km. Short-term observation at multiple locations can be compared to the downscaled parameters (such as wind speed) and these errors can be reduced with Model Output Statistics (MOS) equations. The MOS equations are used to make statistical adjustments to the modeled dataset. For the WWSIS, 3TIER developed the wind dataset, hour-ahead and day-ahead wind forecasts. The wind data for the WWSIS was generated using the Weather Research and Forecasting (WRF) mesoscale NWP over the western United States at 2-km, 10-minute resolution for the consecutive years 2004-2006. Each domain was run in three-day blocks which were merged together and smoothed at the seams [3]. It was discovered that the days with seams exhibited more significant variability than the days without seams in the Arizona region. To validate the large spikes in wind speeds, five sites in the northern Arizona region where meteorological data is available were compared to the simulation data, including Gray Mountain, Anderson Canyon, Springerville, Aubrey Cliffs, and Bullhead City (see http://wind.nau.edu/anemometer/wind_data.shtml for more information about these sites). Figure 2 illustrates an example validation site for January 1, 2006 where an anomalous wind spike is observed in the 100m NREL simulated wind data set (see the large spike displayed by the light blue line at the beginning of Jan. 2). Additionally, 3TIER developed a wind and power production data set for the northern Arizona region for NAU and was used for the selected sites to compare the NREL data set.

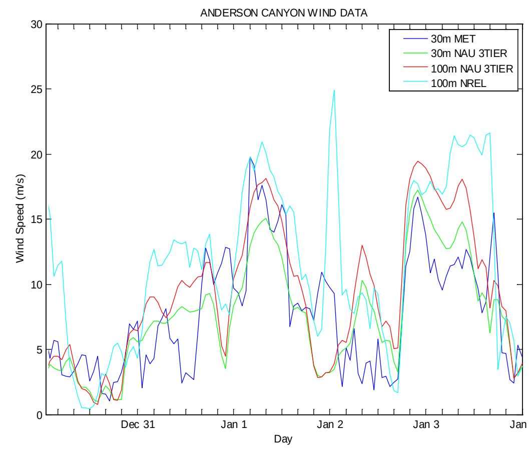

Figure 2: NAU 3TEIR wind simulation validation, showing an anomalous wind spike in the simulation data on Jan. 2.

To solve this modeling fault, data from every third day was eliminated. The corresponding daily energy levels were reanalyzed and determined acceptable for energy and production simulation analysis. 3TEIR also developed a day-ahead wind forecast using a coarser resolution for the hourly forecast with a different input dataset. As a consequence, the wind forecasts were found to have a significant positive bias where the total annual energy of cumulative wind plant forecasts was greater than the cumulative annual energy of the simulated power production. To remove this bias in total energy, the hourly wind forecasts were de-rated by 10% within the study footprint and by 20% for the rest of the WECC.

The heart of the WWSIS is an hourly cost production simulation of the balancing areas in the study footprint using GE's Multi-Area Production Simulation (MAPS) Model. MAPS performs a day ahead unit commitment and an hourly dispatch recognizing transmission constraints within the system and individual unit operating characteristics [4]. The WECC system was modeled as 106 separate load areas, each with their own load profile, generating plant portfolios, and transmission capacity with adjacent areas, while being assigned to 20 transmission zone areas with limited transfer of energy between the areas. The system was committed and dispatched in a cost-effective, rational manner recognizing transmission limits and cycling capabilities of the individual generators. For the hydro facilities, the energy available each month at each hydro plant was defined by a historical ten-year monthly energy average, along with minimum and maximum permissible generation values. Each hydro facility was allowed to follow the load within the defined monthly energy parameters.

Using MAPS, GE conducted hourly production simulation analysis of three base scenarios founded on the combinations of physical transmission areas and the trade-offs between using local and remote resources. Each scenario was run at three levels of wind power penetration (10%, 20%, and 30%), and three levels of solar power penetration (1%, 3% and 5%). Seventy percent of the energy from the solar power was derived from concentrating solar power (CSP) with six hours of storage and 30% from photovoltaics (PV). Table 1 displays the combinations of wind and solar penetration levels for each study area in the WECC.

Table 1: Combinations of wind and solar power modeled within the WECC for various penetration levels (% of load energy) modeled in the WWSIS.

Penetration	Wind and Solar Energy (% of load)
30%	30% wind, 5% Solar in Footprint 20% wind, 3% Solar out of Footprint
20%	20% wind, 3% Solar in Footprint 10% wind, 1% Solar out of Footprint
20/20%	20% wind, 3% Solar in Footprint 20% wind, 3% Solar out of Footprint
10%	10% wind, 1% Solar in Footprint 10% wind, 1% Solar out of Footprint

These penetration levels were used in investigating, among other factors, the capacity value of wind and solar power resources, the effect of balancing area cooperation, and the effectiveness of hydro power in addressing the enhanced variability and uncertainty in system operation caused by wind and solar power. In addition to these penetration levels, three basic scenarios were considered concerning where in the WWSIS footprint that the wind power was assumed to be installed. These scenarios are:

- In-Area scenario – uses local resources within each “transmission constrained” area within the WWSIS footprint by selecting the best sites in correspondence to a mix of energy value, geographic diversity, and capacity factor. These transmission constrained areas correspond roughly to the state boundaries within study footprint, with the exception of Colorado, which is split into and east and west side at approximately mid-state.
- Mega-Project scenario – was created by trading out the lower ranked wind sites (ranked by capacity factor) of the In-Area scenario by higher capacity factor remote resources.
- Local Priority scenario – uses a more realistic build-out of wind sites and transmission combining both in-state and remote resources.

Due to the large number of scenarios, a shorthand naming convention was devised to describe the various cases as shown in Table 2. For example, a case named L20R would refer to the Local Priority scenario with 20% penetration with the state of the art forecast. Note the “Preselected” penetration level corresponds to wind and solar power that is either already functioning or in the process of being built (also call the “No New Wind” case) [5].

Table 2: Scenario naming conventions.

Scenario	Penetration level	Forecast
I - In Area	Pre - Preselected	P- Perfect Forecast
M - Mega Project	10 - 10% scenario	R - State of the Art Forecast
L - Local Priority	20 - 20% scenario	N - No Forecast
	2020 - 20/20% Scenario	
	30 - 30% scenario	

HYDROPOWER CONSIDERATIONS

There are many generation resources located in the study footprint, including significant amounts of hydropower. Hydropower is a very flexible generation resource but can be heavily constrained due to higher priority functions and non-power regulations and constraints. For this reason, the use of the hydropower as simulated in a cost production model such as MAPS can easily be incorrectly modeled. With respect to the WWSIS, concerns that arise are related to proper modeling of the constraints and hydrological conditions (i.e. available capacity, upper and lower generation limits, flow and ramping limits due to environmental considerations, etc.), proper commitment and dispatch of the hydropower, and accuracy of the supporting hydropower data. For example, due to recent drought years in the southwest region of the United States, the water elevations behind many reservoirs have dramatically decreased.

The available capacity for power production at a hydro power plant is directly related to the height of the water behind the dam as shown below:

$$P = \eta \gamma Q h \qquad (1)$$

Where P is the power, η is the efficiency of the hydro turbine, γ is the specific weight of the water, Q is the flow rate of the water, and h is the height of the water level above the hydro turbine. Figure 3 illustrates the available generation capacity of Glen Canyon Dam as a function of water release and water elevation (shown in feet above sea level). As can be seen, the available generation capacity varies significantly with elevation of the water behind the dam. Since hydropower plants often have relatively low capacity factors, on the order of 25% to

50%, they typically have more capacity than water to run through the turbines. From a system operation perspective, the extra capacity, though not often used, can be available as fast responding reserve (spinning and available within less than a second, or non-spinning but available within 10 minutes). Since reserves can be an expensive ancillary service if provided by a thermal resource (e.g. a gas turbine), it can be important to model the reserves available at the hydro power plants in order to correctly model the integration impacts of renewable energy resources.

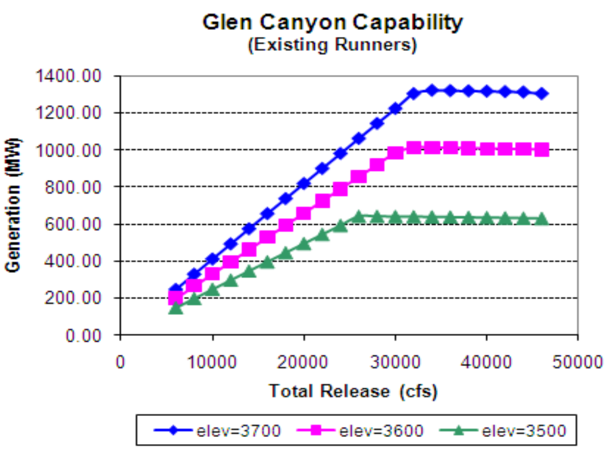

Figure 3: Glen Canyon available generation capacity as a function of water elevation and release.

Beyond these basic modeling concerns, there are many important questions to be answered such as: What is the value of hydropower as a balancing resource and how will the use of the hydro be impacted when large amounts of renewables are integrated into the system? To answer these questions, an in-depth analysis was conducted to compare a series of MAPS simulations, and contrast the simulation data to actual production patterns. Two of the largest hydropower facilities in the WWSIS footprint were selected and examined including:

- Hoover Dam (Nameplate Capacity 2,074 MW)
- Glen Canyon Dam (Nameplate Capacity (1,296 MW)

These two dams are both located on the Colorado River in Northern Arizona.

Downstream of Glen Canyon Dam is Grand Canyon National Park, and thus there are some fairly stringent environmental regulations regarding the release of flow through the dam. During the period of 1963 through 1991, Glen Canyon Dam was operated primarily to produce power during on-peaking hours while meeting minimum flows during the remaining hours. These operations resulted in 7-12 foot fluctuations in river elevation below the dam. These historical operations have been shown to affect aquatic resources [6], riparian resources [7] and the quality of recreation [8]. The Operation of the Glen Canyon Dam Environmental Impact Statement (GCDEIS) initiated in 1989 to minimize the downstream environmental impacts and cultural resources and Native American interests. Furthermore, in 1996, the Secretary of the Interior issued a record of decision on future operations of Glen Canyon Dam (based largely on the Endangered Species Act) that the facility will be operated under the Modified Low Fluctuating Flow (MLFF). The MLFF has set restrictions on maximum flow rates, minimum flows, ramp rates, and the daily change in flow thus reducing fluctuations in river elevation to range from 1-3 feet, thus protecting downstream resources but limiting the dam's flexibility. For example, the historical up and down-ramp rates where unrestricted where as under the MLFF, these are restricted to 4,000 cfs/hour and 1,500 cfs/hour, respectively [9].

With regards to Hoover dam, its top priority function, beyond flood control and preservation of the structure, is the delivery of water to downstream customers such as irrigation districts and municipalities. Thus, the water orders are what primarily govern the magnitude of flow releases from Hoover, and consequently what is available for generation. The water and power customers of Hoover dam have been negotiated by law, and the authority and guidelines to operate this facility, as well as all others on the Colorado River, is governed by a body laws and regulations collectively known as the "Law of the River" [10]. Despite all the regulation, Hoover power plant is still operated as a very flexible resource, providing important ancillary services to the power system in the Southwest United States. Water deliveries from Hoover are defined on a monthly basis, and these deliveries in combination with the height of the water behind the dam define the maximum generation capacity available and energy production available to the Hoover power customers each month. Within these limits, the power customers are free to use the energy and power at their convenience. The power customers either operate electrical control areas and use the Hoover power to their best advantage, or they contract with another organization that will serve their load and utilize the Hoover power on their behalf. In this later case, the Hoover power is typically used for its flexibility and ancillary services. Thus, an assumption made in this study is that, within the constraints imposed on the hydro power plants, that the power and energy will be dispatch rationally, for the benefit of the power system.

One question that will not be answered in this study relates to cost allocation. For example, if the hydropower is utilized more for its flexibility when integrating the wind and solar power described in the scenarios above, then there will be increased maintenance and operations costs at these plants. No attempt is made to allocate these costs within this study or to estimate the impact on the hydropower customers.

HYDROPOWER ANALYSIS

Hoover Dam and Power Plant

In the first evaluation, actual hourly production data from Hoover dam was compared to that of the "No New Wind" scenario in MAPS for 2006. The daily averaged generation data is illustrated in Figure 4. The fact that a ten-year average of the monthly energy production from the Hoover was used in MAPS is evident in the plot, as a significantly larger amount of generation occurred in the simulation than in the 2006 historical data. The actual 2006 generation from Hoover was 3.77 MWh, while the generation in the No New Wind scenario was found to be 4.56 MWh, an increase of 21% over actual. Alternatively, the seasonal variations and profiles of the No New Wind simulation followed a similar shape throughout the year.

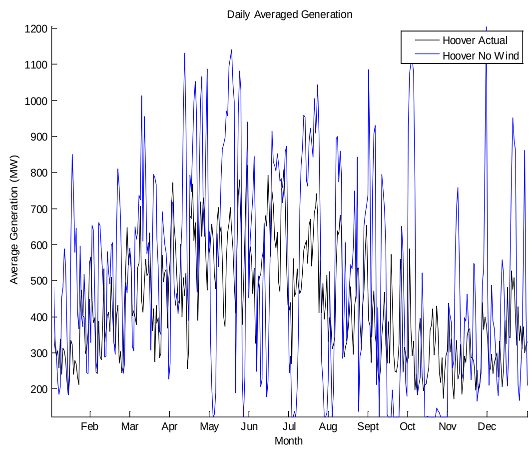

Figure 4: Hoover Dam comparison between daily averaged power production from actual 2006 data and the MAPS output for the "No New Wind" scenario.

An "average weekly profile" for the peak load month of July is illustrated in Figure 5. Observing the high load hours (HLH) and low load hours (LLH)[1] on the weekly profile, the MAPS model is entirely peak shaving while the actual data, though also peak shaving, does continue to generate through the LLH periods. Note the minimum generation level from Hoover power plant was 21 MW during 2006.

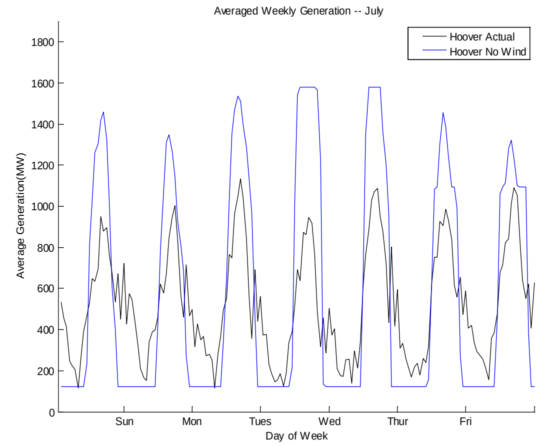

Figure 5: Comparison between "averaged weekly profiles" of actual data and the No New Wind scenario simulation data from MAPS for the peak load month of July.

To illustrate the averaged daily generation profile, monthly averaged diurnal distributions were created as shown in Figure 6. The diurnal generation patterns for the No New Wind scenario generally resemble the actual generation profiles throughout the months, with the exception of a shift in morning generation during the winter months.

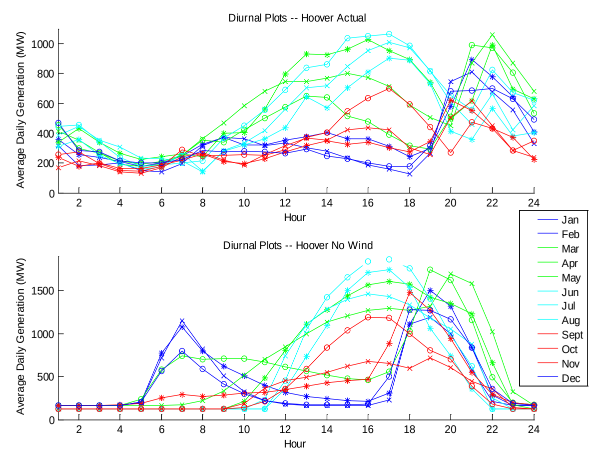

Figure 6: Monthly diurnal distributions of Hoover for actual data and MAPS No New Wind scenario[2].

Figure 7 shows histograms of hour-to-hour changes in generation at Hoover power plant for the actual and MAPS No New Wind data sets. In these plots, "Annual" refers to all hours of the year. It is evident that the though the MAPS No New Wind simulation does not move the generators at Hoover as frequently as the actual operation (because it tends to peak

[1] It is noted that High Load Hours is defined as the time period between 6 am to 10 pm and Low Load Hours is defined between the time period between 10pm to 6am.

[2] Note scale shift between graphs.

shave more), there are more very large changes in generation, up to the nameplate capacity, that occur during the HLH.

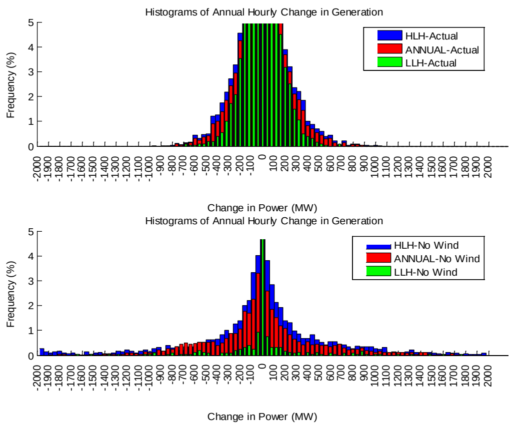

Figure 7: Histograms of hourly changes in generation for Actual and No Wind at Hoover.

Table 3 shows some statistics of the hourly changes in generation for the actual data and the No New Wind data sets. As the histograms have illustrated, the No New Wind data set has shown more variability on the tail ends of the histogram due to peak shaving in HLH. By taking the average of the absolute value in hourly changes, the real magnitude of hourly changes in generation is exposed. Interesting enough, while the hourly changes during the HLH change modestly between the data sets, the difference in the changes during the LLH is much more significant.

Table 3: Statistics for hourly changes in generation at Hoover power plant for the actual and No New Wind data sets.

Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of Absolute Value (MW)
Annual – Actual	-0.006	209	155
HLH – Actual	0.038	229	173
LLH – Actual	-0.076	149	112
Annual –No New Wind	-0.149	305	133
HLH – No New Wind	0	431	212
LLH – No New Wind	0.005	133	22

For an example case that demonstrates how Hoover's hydro power production will be impacted when large amounts of renewables are integrated into the system, the L20R scenario was chosen to compare to the No New Wind scenario (as defined in Table 2, the L20R case indicates the "Local Priority scenario at a 20% penetration of wind power assuming a professional wind forecast). As a point of reference, there is 3,030 MW of wind power in the No New Wind case and 18,180 MW of wind in the L20R scenario for the footprint. Figure 8 compares the daily averaged power production from the No New Wind and the L20R cases. As shown, the generation profiles match well during the peak summer months, but that there is more variability in the Hoover generation during the winter and spring months in the L20R case due to the occurrence of high spring winds in the West.

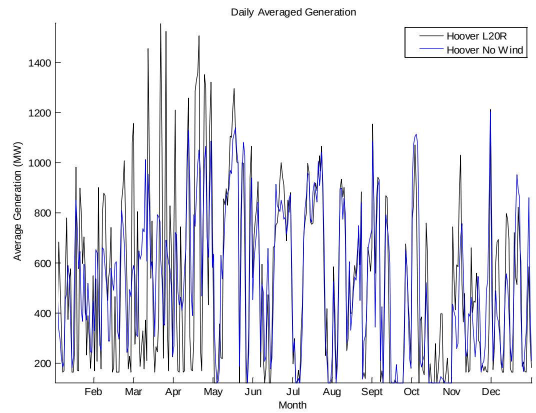

Figure 8: Daily averaged No Wind and L20R scenarios.

Glen Canyon Dam and Power Plant

Glen Canyon Dam has many operating criterion it must comply with and is operated under the Glen Canyon Dam Final Environmental Impact Statement and Record of Decision. This limits the maximum and minimum generation/flow along with limits on up and down ramps during certain periods of the day. This is no more evident as in the comparison between Glen Canyon's actual and No New Wind data sets illustrated in Figure 9.

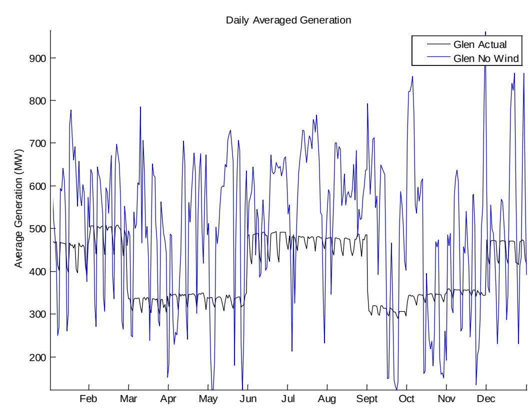

Figure 9: Actual averaged daily generation at Glen Canyon Dam and as simulated in MAPS in the No New Wind scenario.

Looking at the actual data set, the difference in generation between the shoulder and peak production months can be observed. Higher generation occurs during the summer months to help meet cooling load demands in the region, and to move the water downstream as required by the Law of the River. The diurnal distributions between the actual and No New Wind data sets as illustrated in Figure 10 exposes roughly similar daily generation profiles (though the magnitude of generation scales are different), but the pattern from the MAPS No New Wind simulation shifts generation to later in the afternoon while the actual data remains fairly constant throughout the day with exception to the early morning hours.

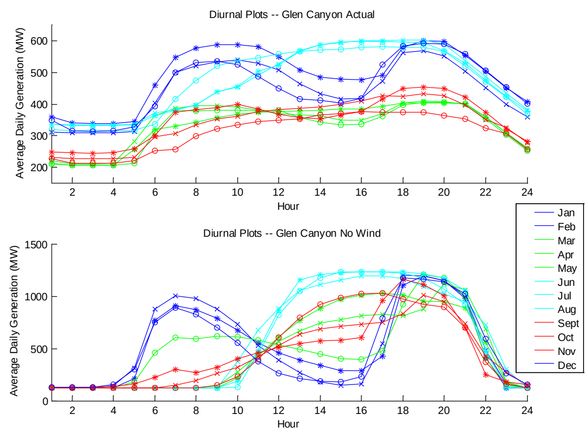

Figure 10: Average monthly diurnal distributions of generation at Glen Canyon Dam for the actual and No New Wind data[3].

Figure 11 illustrates the histogram of the hourly changes in generation at Glen Canyon for the actual and No New Wind data sets where there are more hours of little movement in generation from the No New Wind simulation, but also that there are more larger changes especially during HLH. The focused view of the histograms is presented where the frequency displayed on the vertical axis has been limited to 5 %.

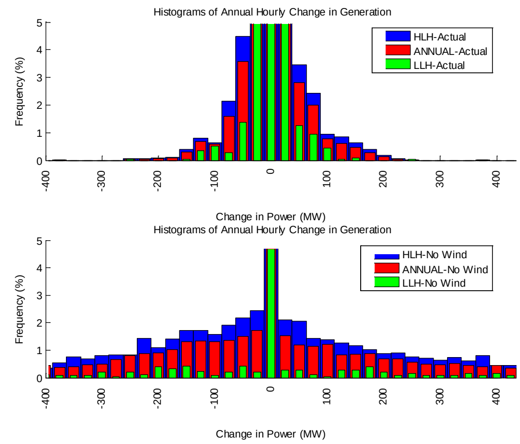

Figure 11: Histogram of hourly changes in generation for Glen Canyon Dam.

It was found that the magnitude of hourly changes in generation had a dramatic increased from the actual data to the No wind data set. For instance, on an annual timeframe, the average of the absolute value had increased from 19 MW to 105 MW in the No Wind data set, an 18% increase. Similarly, during the HLH, an increase from 23 MW to 142 MW was observed for the average of the absolute value. During the LLH, a modest increase of 8 MW to 25 MW was observed. To demonstrate the changes in hydro use due to integration of the wind and solar, the No New Wind scenario was compared to the L20R scenario. Figure 12 demonstrates a plot of the averaged daily generation for these two scenarios, indicating increased usage of the hydro flexibility during the spring months, slightly less during the winter months, and remaining nearly unchanged throughout the peak summer months of the year.

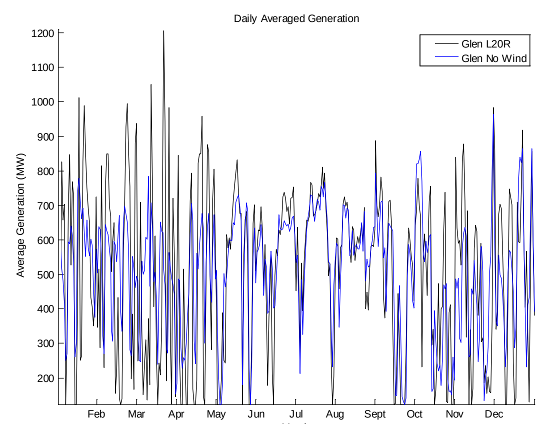

Figure 12: Daily averaged generation between No Wind and L20R data sets at Glen Canyon.

One conclusion that can be drawn from these comparisons is that the usage of Hoover and Glen Canyon Hydropower in the MAPS simulations differs in some substantial ways from the actual usage. This results in part due to the flow constraints and

[3] Note scale of graphs.

operation criteria at these dams (typically due to non-power functions) not being well modeled in MAPS simulation, and because the MAPS simulation used hydro resources derived from a 10-year historical average and not the actual 2006 monthly flows and capacities. One implication is that the flexibility available at these hydro plants would be more heavily used if not otherwise constrained.

All Hydropower in the WWSIS Footprint

To determine the overall impact due to large amounts of wind and solar power on all the hydropower in the WECC, a series of comparisons were made that look at the hydro system collectively. For the MAPS simulations to be compared the hydro generation (as well as all generation) was scheduled to net load; that is, hydro was scheduled to the load modified by the forecasted wind, also referred to as “load net wind.” For each scenario modeled, the monthly energy and max/min hydro capacities remained the same. It was found that there is little change in the hydro facilities schedule between the Local Priority and In-Area scenarios. For this section, the In-Area scenario is now being considered rather than the Local Priority scenario.

Figure 13 illustrates the annual duration curve for the hydro operation for the same set of In-Area scenarios. From this aggregate level, there is no significant shift in hydro operation as compared to the No New Wind scenario. It was also found that for the hourly changes in generation for all the hydro power plants in the WECC there was no significant difference between scenarios.

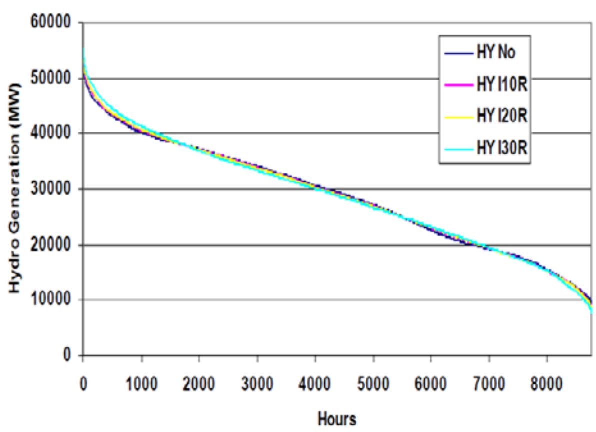

Figure 13: Duration curve of annual hydro generation in WECC.

Economic Impact of Hydropower Flexibility

One of the positive effects of using hydropower to meet the increased reserves and flexibility requirements caused by integrating large amounts of wind power is reduced overall system operating costs. This is due to hydropower being very low cost compared to other flexible resources such as combustion turbines. To the extent that there are cost savings, this represents an opportunity for those that possess the hydro generation to benefit economically. MAPS, being a cost production model, is well suited to address economic issues related to system operation. To attend to the question of the value of hydro power versus other resource in providing the ancillary services required by the increased renewable energy, MAPS was run with the hydro scheduled to load only rather than load net wind. The change in overall operation costs to serve load in the WWSIS footprint is shown in Figure 14 For the lower wind penetration levels of 10% and 20%, the increase in cost is modest at $16M to $27M, corresponding to a cost increase per MWh of wind energy of $0.17 at the 10% penetration level and $0.22 at the 20% penetration level. At a 30% wind penetration, the cost increase is more significant at $203M, or $0.97 per MWh of wind energy. It is worth pointing out that not all of this cost increase is due to the variability and uncertainty of wind energy, as there is some solar power in the system also. However, since wind energy is the large driver at the high penetration rates, these numbers serve as a reasonable approximation. One conclusion to draw from this plot is that scheduling the hydro in a way that accounts for the wind energy is of economic benefit in the system.

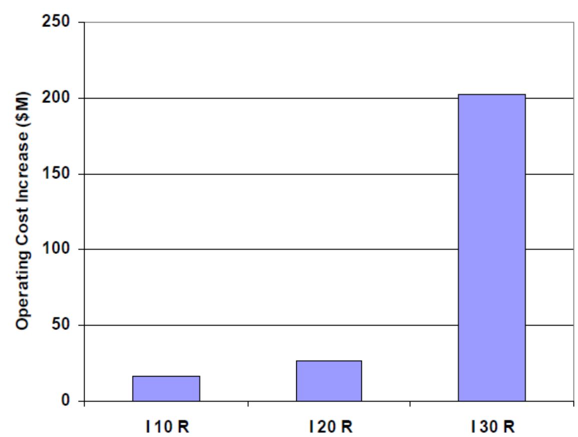

Figure 14: Operating cost increase in the WECC due to dispatching hydro to load only versus load net wind.

In order address the question of the benefit of hydropower’s balancing capabilities; individual hydro plants were modeled as flat block monthly outputs (thus removing all flexibility and reserve capabilities of the hydro in the MAPS model). The available generation capacities were reduced to an averaged value such that the facility was not able to provide any reserves and was run at a constant level for every hour during a given month in order to generate the required monthly energy at each hydro plant. The operating costs of the flat hydro or flat block scenarios are compared to their corresponding non-flat block counterparts (e.g. the operating costs of the I10R scenario is compared to operating costs of the I10RHf scenario). Figure 15 depicts the impact on the WECC operating cost of the flat block hydro as renewable penetration levels increase. The results displayed essentially show a “bookend” of the value of the hydro flexibility and reserves, and that it varies from $860M to $1180M in reducing the overall system operating costs, or $10.00 to $4.00 per MWh of wind energy.

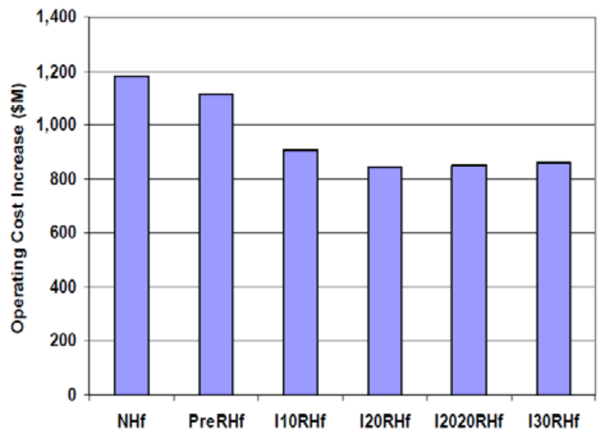

Figure 15: Incremental operating cost impact of modeling the hydro as a flat block each month with no flexibility or reserve capability. “Hf” implies hydro modeled as a flat block. (NHf – No New Wind; PreRHf – Preselected Wind; I10R – In-Area 10% Wind in study footprint using professional forecast, I20R – 20% Wind, I2020R – 20% Wind in both in and out of study footprint, I30R – 30% Wind in footprint)

CONCLUSIONS

It comparing the MAPS output to the 2006 actual data, it was found that the MAPS model possessed significantly more energy (due to using a 10-year average of hydropower instead of the 2006 actuals), and the model used the more in a peak shaving mode. This was partly due to hydro system constraints not accounted for in the MAPS model (such as environmental constraints on Glen Canyon) and due to recent low elevation levels resulting from drought. It was found that the method of using the flexibility at each hydro facility changes, generally increasing throughout the high load hours (in particular more large changes in generation and more hours of no significant change). Results have shown that as renewable penetration levels increases, the hydro system in aggregate has little change in generation pattern, though there may be significant changes at individual plants. By dispatching the hydro to load net wind, it was found that operating cost could be reduced by $200 million per year in the WECC, increasing the value of wind and solar by roughly $1/MWh. Additionally, the balancing value of hydro was found to reduce WECC operating cost by offsetting more expensive generating systems by up to $1 billion per year. Conversely, this cost could be reversed if hydro operation were severely constrained such as maintaining constant river flow.

ACKNOWLEDGMENTS

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