FINAL REPORT OF THE GTMAX MODEL REVIEW PANEL

Tuesday, September 04, 2012

Report of a Workshop held August 31 and September 1, 2011 in Flagstaff, Arizona

At the invitation of the Grand Canyon Monitoring and Research Center (GCMRC), three independent experts reviewed the GTMax power operation model and its uses for economic analysis of issues relevant to the Glen Canyon Dam Adaptive Management Program (GCDAMP). This document presents their findings and recommendations.

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EXECUTIVE SUMMARY

GTMax belongs to a class of models known as production simulation models. The model's primary objective is to simulate the most efficient operation of the Colorado River Storage Project (CRSP) hydroelectric facilities at least cost. As is typical of such models, it simplifies what is in reality a very complex system of inter-related electrical generation facilities and decision factors, and therefore, like all such models, it is an imperfect representation of reality and has limitations in how it can be applied.

As explained during the workshop, and discussed in the report, the GTMax model was developed by Argonne National Laboratory at the request of Western Area Power Administration (hereafter, Western) to assist Western with daily scheduling of CRSP operations and for use in special purpose studies to evaluate various operating policies. The model assesses the operational efficiencies and trade-offs associated with various operating scenarios for the CRSP system as a whole. Glen Canyon Dam is just one component of the CRSP system, and decisions made at one facility affect all the others, so there are significant challenges associated with extracting effects of Glen Canyon Dam operations from the rest of the system using this model. This is further complicated by the use of RiverWare simulation output as an input to GTMax; since RiverWare software was not part of our review we are unable to make further statements about how RiverWare output affects GTMax analyses and results.

The model can be constrained according to various assumptions about how the system has been or will be operated. It relies on various data as inputs, uses a suite of software tools to solve a complex system of equations to reduce all operating objectives and constraints to a single number. That number is the total cost of system operation to meet the specified load for the designated time period. This single number permits comparisons between different operating scenarios. The report describes the various components of the GTMax model and discusses these attributes in relation to its original intended purpose, as well as in relation to other models of its type and recent applications of the model.

The research review panel members (hereafter "reviewers") conclude that GTMax is generally well-suited to the original purpose for which it was designed, i.e., to provide comparative assessments of various operational options over relatively short-time frames—one year or less. The reviewers had concerns, however, with the model's application for other purposes for which it was not originally designed and is not well-suited. Specifically, the model is not well-suited for forecasting economic implications of long-term operational scenarios. The reviewers express reservations with how the model addresses capacity issues, reserve commitments, the valuing of ancillary services, and long-term risk factors, noting that proper valuation of these factors is essential for making accurate long-term economic forecasts. The reviewers point out that because the GTMax model was designed primarily to evaluate short-term operations, developers of the model did not include long-term planning features such as capacity expansion algorithms and algorithms for valuing ancillary services, reserve commitments and various risk factors, which limit its utility for long-term forecasting purposes and raises questions about the accuracy of some previous study results.

The report explores some of the data inputs used by the GTMax model and discusses how the choices made about those inputs influence subsequent model outcomes. For example, the model relies on inputs from a separate hydrological model, RiverWare, which is used by the US Bureau of Reclamation (hereafter, Reclamation) to forecast annual water volume distributions. The assumptions used to create the outputs from the RiverWare model that are subsequently used as inputs to the GTMax model were unclear to the reviewers, but they noted that RiverWare appeared to take into account the fact that the value of the hydropower resource is generally greater in summer and winter vs. spring and fall, which in turn had implications for the results generated by GTMax. The reviewers also had questions concerning Western's choices of prices for valuing capacity in some of their "economic" analyses, noting that the basis for those choices was unclear but had significant implications for modeled outcomes, such as those presented in Argonne's 2010 Post-ROD analysis report. They suggested that more transparency surrounding such choices was needed in the future. They recommend that Western generate diagnostic reports with its modeling runs to clarify the effects of the underlying assumptions and inputs used for generating model results. They also recommended that the GTMax model itself should be documented in writing for the benefit of those who wished to understand its structure and functions in more detail.

Considerable discussion of the role of pricing, and its consequences for modeling, is included in the report. The reviewers note that choices made in valuing certain factors, such as capacity, have significant effects on modeling outcomes. The reviewers expressed concern that there was insufficient clarity in past studies as to why some prices for power replacement costs were chosen over others. They also questioned the proposed use of an expanded version of the model for predicting prices at trading hubs. They suggest that other methods, such as econometric modeling, may be better suited to that purpose.

Below are some additional observations and recommendations from the report:

1) Western needs to develop the conceptual framework and quantitative tools to better prepare for and be able to characterize its participation in ancillary services markets.

2) For relatively modest outlay Western could conduct an econometric analysis of pricing at the major trading hubs it employs in GTMax scenarios.

3) The review panel members observed that Western uses the terms “financial” and “economic” to characterize two types of analyses involving very specific and somewhat limited applications of the GTMax model (see pages 28-29 for further details.) These analyses do not encompass the full suite of analyses typically associated with use of these two terms.

4) The reviews suggest that using GTMax to model the interface of the CRSP with the WECC system would require significant enhancement, particularly in terms of its transmission typology to effectively represent the combined system. The GTMax model does not have the geographic scope to study possible consequences of policy changes on other parts of the WECC. They suggested that it might be possible to conduct such an analysis using GTMax if it were supplemented with more extensive models to properly assess both the short-term and long-term effects of actions by Western and the rest of the WECC on each other.

In summary, the GTMax model and Western’s analytical framework are designed primarily to evaluate short-term operations. The authors of the GTMax model did not include long-term planning features, such as long-term capacity expansion algorithms, which limits its utility for forecasting economic implications of long-term operations. The model is not capable of modeling operations of less than one-hour duration, which means that the potentially significant economic value of ancillary services cannot be adequately represented in the modeling results. The model relies on inputs from the RiverWare model, which are provided by Reclamation; this constrains Western’s ability to modify hydrogeneration scenarios for assessing impacts of climate change or river diversions. Thus, the model does not facilitate convenient or efficient evaluation of alternative assumptions that may be substantially different in the future. Furthermore, the model does not have the geographic scope or an adequate representation of transmission to study possible consequences of policy changes in other parts of the WECC. The strength of the model as currently formulated lies in its ability to examine the consequences of following specified management regimes over short periods of time when water conditions, electricity prices, and other variables are reasonably stable.

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INTRODUCTION

The Grand Canyon Monitoring and Research Center (GCMRC) convened a workshop on August 31 and September 1, 2011 in Flagstaff, Arizona to discuss the GTMax model. The model has been used by the Western Area Power Administration (Western) to model the economic effects of the operation of a variety of river systems including the Colorado River Storage Project, the Glen Canyon Dam and other facilities on the Upper Colorado River Basin. Representatives attended the workshop from Western, GCMRC, Argonne National Laboratory (ANL), developers of GTMax, and various stakeholders with interests in the operation of Glen Canyon Dam. The panel, designated as outside independent experts, was also invited to participate in the discussions:

- Dr. Edward Kahn, Special Advisor, Analysis Group, Inc., San Francisco, California
- Dr. Verne Loose, Senior Economist & Principal, Verne W. Loose Associates, LLC, Albuquerque, New Mexico
- Dr. Michael Schilmoeller, Senior Power Systems Analyst, Power Planning Division, Northwest Power and Conservation Council, Portland, Oregon

Our role as independent experts was to review the GTMax model and its uses for economic analysis of issues relevant to the Glen Canyon Dam Adaptive Management Program (GCDAMP). This document represents our findings and recommendations from the workshop.

PURPOSE OF THE WORKSHOP

The purpose of the workshop was to review the capabilities and uses of the GTMax model toward the investigation of possible changes in the operating regime of the Glen Canyon Dam (GCD). Development of wholesale markets for electricity in various regions of the country provides opportunities for timely bidding of generation resource owners to improve their profit position. These new markets introduced “value-based” compensation for generation, replacing the “historical cost-based” compensation of the regulated investor-owned utility (IOU) model. The evolution to multilateral wholesale markets is not complete. In particular, in the Rocky Mountain west, the regulated IOU business model predominates. This is also true in the larger Western Electricity Coordinating Council region (a.k.a., “Western Interconnection”), with the single exception of a large portion of California in which the wholesale market business model is in effect. The existence of this wholesale market in the WECC region presents opportunities for western generation asset owners to increase returns to operation of their plants. The combination of potential rapid response to fluctuations in the electricity supply and demand balance and the state-mandated renewable portfolio standards (RPS) has the potential to expand the opportunities for profitable operation.

These institutional changes are important to Western, its customers, and the GCMRC, because they mean that traditional methods of economic evaluation may need to be modified to reflect new economic products and markets. For a number of years, Western has been conducting much of its economic analysis using the GTMax model. The purpose of the Flagstaff workshop was to review the previous and proposed future uses of GTMax and assess the applicability of the model to anticipated future economic and financial issues. To put these questions in proper perspective, it is useful to first review briefly the nature of the changes in the organization of the electricity industry. The next section, **Three Business Models**, provides this overview. Next, the section entitled

Review of **GTMax** reviews the basic structure of the GTMax model. The section entitled **Observations and Findings** discusses the suitability of GTMAX for the purposes identified here. Finally, the **Conclusions and Recommendations** section provides suggestions for enhancing the analytical strength of Western's tools and future studies for application in the Glen Canyon Dam Adaptive Management Program.

THREE BUSINESS MODELS

The exchange of electricity products occurs through various market structures that overlay physical and operational organization of the grid. Areas that operate under the bilateral transaction paradigm (i.e., the regulated IOU business model) are referred to as Traditional Scheduling Areas. In contrast, formal markets generally operate in conjunction with an Independent System Operator (ISO) or Regional Transmission Organization (RTO). The southeastern United States contains the Southeast Reliability Corporation (SERC) and the Florida Reliability Coordinating Council (FRCC) regions that have no formal markets, ISOs, or RTOs. The Western Interconnection represents a mix of the two approaches since it contains two ISOs (the California ISO and the Alberta ISO) with formal markets, while the rest of the Western Interconnection functions under the bilateral transaction paradigm.

ISO/RTO with Formal Wholesale Markets

ISOs and RTOs manage grid operations within their territories and also operate markets through which energy, ancillary services, and capacity resources are procured. Seven ISOs operate at the present time in the U.S. (several extend operations into Canada). Like all Transmission Service Providers, ISOs are required to file Open Access Transmission Tariffs (OATTs) with the Federal Energy Regulatory Commission (FERC). OATTs define and implement market definitions and operations and specify details of accounting and settlement procedures. Market participants within these areas must file substantial technical and financial paperwork with the ISO, have their generation assets tested and approved to meet the technical engineering standards required to implement North American Electric Reliability Corporation (NERC) reliability standards, and demonstrate that they are financially sound. Individual generator owners operating in formal markets bid their services pursuant to a financial incentive as opposed to an obligation to serve load.

Pure Traditional Scheduling Area

The SERC and the FRCC regions are examples of typical traditional scheduling areas. Both are comprised of utilities that have more-or-less maintained their historical organizational. They are regulated by state public utility regulatory authorities as well as by FERC and have an obligation to serve the load within their defined territory. They schedule energy and power transactions, and coordinate operations as well as system expansion planning to maintain grid reliability following the same NERC criteria. Entities may engage in bi-lateral trades with other adjacent utilities in order to meet their obligations. No formal markets exist in these traditional scheduling areas.

Mixed Business Model among NERC Regional Entities

The mixed business model is characteristic of NERC regional entities that contain a combination of market and non-market areas within their boundaries. The WECC represents a mixed model due to the presence of formal markets under the California Independent System Operator (CAISO) and Alberta Electric System Operator (AESO) with the balance governed by a system very much like that in the southeast. The presence of formal markets in WECC, particularly the CAISO market, presents opportunities and obligations to generation asset owners whose assets exist outside of the CAISO borders. They are still used to meet load-serving obligation within their balancing areas, but they now also can bid their assets into the California market. There are also informal bilateral wholesale markets in WECC at trading hubs such as Palo Verde and Mid-Columbia.

As the competitive business model continues to expand into or influence non-market areas, change will continue to take place. This variety of physical, operational, and market organization structures makes it difficult to generalize about the methods, procedures, and effects of hydro generation participation now and in the future. The same can be said for integrating large amounts of variable generation capacity into the existing capacity mix. However, one ameliorating factor tending to simplify this otherwise complex situation is that fundamental economic behavior driven by cost minimization provides a common foundation that underlies the behavior of participants in both market and non-market segments of the industry.

Formal electricity markets sharpen the profit incentives of all participants, including those that are subject to some, or even considerable, regulation. The role of formal markets is likely to grow in the WECC region (E3, 2011), and Western will need to respond to these developments.[1] One basic set of questions addressed in our review concerns both how and how well GTMax can represent both traditional cost minimization objectives as well as new market opportunities for increasingly monetizing the value of the hydroelectric assets which it markets.

Western's Institutional Context

The macro and regional economic and business context outlined above interacts with Western's business context. In addition, Western must operate within certain other constraints that affect its relationship to its customers and stakeholders.

Most of the hydroelectric facilities in the western U.S.—built with federal funding—were intended to serve multiple purposes including irrigation, flood control, recreation, and electric power production. These facilities are today managed by a number of federal agencies so as to achieve these multiple purposes. All of the dams that comprise the CRSP are considered Bureau of Reclamation (Reclamation) facilities. Management of the water flow is also conducted by Reclamation but is constrained by water delivery and storage requirements, and by purposes consistent with laws and statutes collectively known as "The Law of the River." Reclamation consults with the Colorado River Basin states in its setting of annual and monthly release volumes. Western schedules hourly releases in conformance with the monthly volumes set by Reclamation and to meet contractual obligations for the delivery of electrical power. Western's power marketing responsibility begins at the switchyard of the federal hydroelectric facilities and includes the federal transmission system to interconnected utility systems with the rest of WECC.

CAISO allows generation asset owners outside the CAISO footprint to bid into its markets with appropriate physical and financial representations. Indeed, California requires the energy and capacity from these resources since it is short of generation from within its footprint.

This presents an opportunity for generation resource owners in WECC with available capacity beyond their "native" load. With available excess capacity, Western could bid into California markets when either energy or ancillary services prices make it financially attractive. Timing is critical in this. Generator asset owners must be prepared to react when day-ahead and real-time prices diverge, presenting the opportunity for energy "arbitrage." It is also the case that California Ancillary Services (AS) market prices are among the highest of the seven ISOs, with regulation (i.e. adjustment of electricity supply and demand variations over intervals up to five minutes) being the highest prices of the services that include spin and non-spin reserves. Thus, Western has the opportunity to earn additional revenue if it can respond in a timely fashion.

However, this is not a totally unmitigated opportunity as there is concern among hydroelectric engineers that cycling of turbine generator sets as required by AS market provision might result in extra wear and tear upon the equipment and result in higher operation and maintenance costs as

[1] Recent discussion of an "Energy Imbalance Market" within WECC exemplifies such developments.

well as shortened lifetimes. Thus, it is possible that costs might also increase with increasing revenue. Also, decreased hydrology due to drought conditions and environmental constraints implemented in the last 10 to 20 years have limited Western's ability to generate enough electricity to meet even its contractual obligations with its customers, much less have available capacity to sell into energy or AS markets. Nevertheless, drought conditions can clearly change and if increased water releases for power production can be accomplished within existing constraints on releases, reservoir volumes, and pondage constraints and matched to price spikes in relevant markets, Western has the potential to increase net revenues.

REVIEW OF GTMAX

GTMax belongs to a class of models representing the operation of electricity systems generally known as production cost simulation models. There is a large literature on these models; see, for example, Foley *et al*., 2010; Kahn, 1995; Arnedillo, 2011. Commercial examples of such models include PROMOD, PLEXOS, and U-PLAN. There are others. Reviewing and discussing this literature or any of these commercial products directly is well beyond the scope of this study, Instead we list the important features of GTMax and how those features are implemented in the model. See Table 1. All production cost models have these features but may represent them by different means. For example, most production cost models do not have a very developed hydroelectric analysis algorithm. GTMax is exceptional in this respect.

TABLE 1: GTMAX FEATURES AND THE MEANS FOR IMPLEMENTING EACH

Capability or Feature	How GTMax Implements Each Feature
Typical application	Determining the Incremental cost and river operation implications to Western and the CRSP of alternative policies and contracts
Unique features	Hourly integrated hydro-thermal model with stream and transmission linkages
Objective Function	Minimum variable system cost
Solution Algorithms	Mixed-Integer Linear Program optimized on chronological weekly operations
State Variables	Pumped Storage and forebay water levels
Solution variables	Thermal and hydro unit loading; transmission flows; market electricity purchases; thermal unit start-up; dam spill
Fundamental period	One hour
Solution Period	One week
Study period	User specified-1 week to multiple years typically using representative weeks for each month
Types of Units represented	Reservoirs with and without generation; run-of-river generation; pumped storage; fixed heat rate coal and gas-fired boilers and turbines; cogeneration
Topology	Zonal, at user’s option-typically limited to CRSP
Transmission Algorithm	Economic transport
Principal output	Total variable system cost and revenues from both Western customer and societal perspectives; unit operation, shadow price for hydroelectric generation; system lambda (short-term marginal power prices)
Documentation	Unknown
Support and training	Undetermined
Cost	Undetermined; free for federal agencies

Typical application and unique features

Developers create computer simulation models to solve particular problems or to address specific inadequacies in existing models. For example, the GTMax model evaluates weekly Colorado River operation in the context of the regulated wholesale firm power markets. Several commercial models were available in the mid-1990s that represented the participation of the thermal systems in deregulated markets. Such models had sophisticated calculations for transmission and unit commitment. None of them, however, had adequate representation for the Colorado River system projects (CRSP).

Most commercially available production cost models have very simple representations of the hydroelectric generation system. The standard approach is to divide hydro resources into "base-load" and "load-following" segments for each simulation period. The base load segment is dispatched in all hours of the period. The load following energy is used to "peak shave" the anticipated load profile up to the limit of hydroelectric capacity. The result of this is a flattened load shape that is used to simulate the operation of thermal power plants. This standard heuristic is sensible for systems with relatively small amounts of hydro generation. In systems like the CRSP, however, this simple representation is inadequate. Moreover, the developers of commercial models have not provided the kind of detailed hydroelectric generation representation that Western needed.

Rather than any inherent difficulty, it is perhaps the unique nature of each system that makes the task unprofitable for commercial developers. Not only are the power generation characteristics among dams dissimilar, but also each hydroelectric generation system is constrained by very different non-power considerations. Both the flow through and the level of the forebay and tailrace of each dam are constrained. These elements are constrained for compliance with requirements for fish and wildlife protection, flood control, navigation, preservation of archeological and cultural treasures, and recreation, to name a few. Moreover, dams and thermal generation are tightly coupled. Energy cascades from a dam to all downstream dams and, in some systems; even upstream dams can be affected. The dams can store energy purchased or produced by any thermal generation.

Consequently, when Western was confronted with the need to evaluate and model the CRSP, they collided with the hydroelectric generation limitations of existing models. GTMax was designed to address that inadequacy.

Objective function, solution algorithms, fundamental period

By selectively purchasing and selling power, dispatching or refraining from use of certain resources, and by storing or drawing energy from hydro-electric generation, system operators can provide a given level of service (e.g., energy generation) at least cost. Minimizing costs, however, may not be the most important objective. In any case, all objectives have to be reduced to a single number for a computer model or analyst to compare and rank alternatives plans. That single number is the value of the objective function, a function of all the various variables and constraints.

GTMax is typical in that it minimizes cost subject to constraints. Maximizing revenues, another possible objective referenced in published descriptions of the GTMax model, can mathematically be shown to be essentially the same problem.

Western constrains GTMax differently for different studies. When Western performs what they refer to as a "financial" study, they are constraining net generation and purchases to meet customer loads. The purpose of this kind of study is to find the most economic operation without exposing Western to the vicissitudes of market purchases and sales. Figure 1 illustrates this graphically.[2]

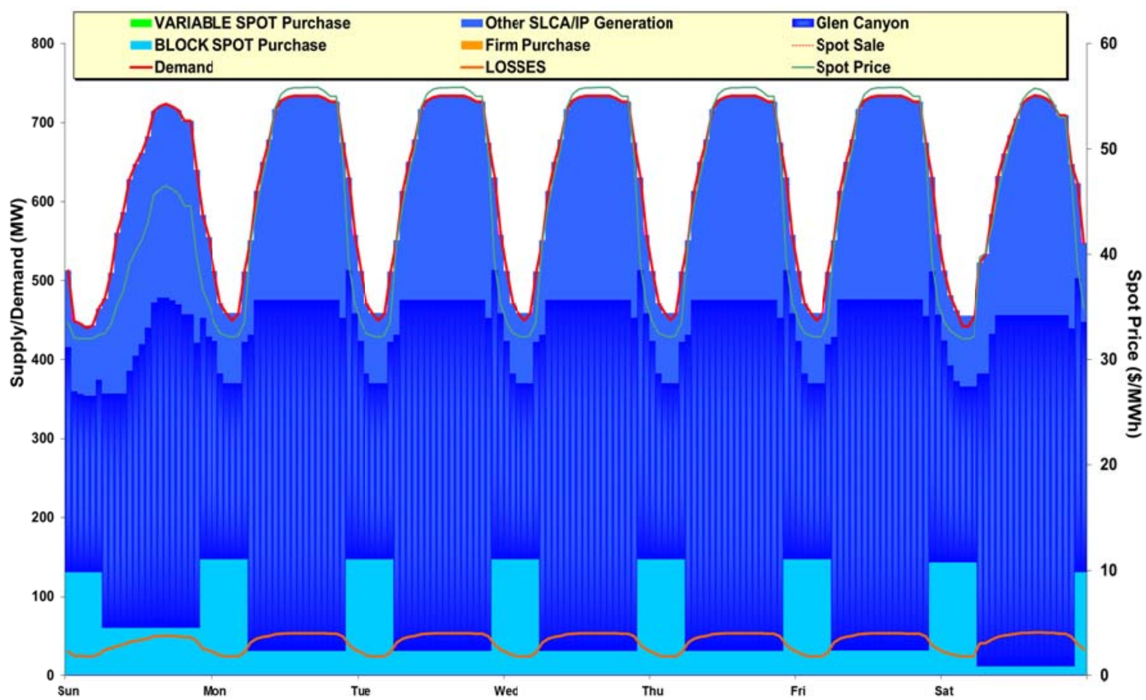

FIGURE 1: DISPATCH FOLLOWS CONTRACT LOAD

When Western does not constrain net generation and purchases to meet customer loads, Western permits the model to purchase and sell in the market to further minimize cost. Western refers to this as "economic modeling." Removing constraints can only improve the economic outcome, given the perfect foresight assumption implicit in these models. If purchases are less expensive than dispatching a Western generation unit, the model will displace the unit. If wholesale power market prices are higher than the generation cost of a Western generation unit that would otherwise be idle, the model will dispatch the unit to sell into the wholesale market. This is illustrated in Figure 2

[2] Source: Veselka, 2011, Slide 13

(Veselka, 2011, Slide 14) below. [3] Figure 2 shows Western's generation going as high as 900 MW, which is above demand. This captures the value of high peak prices. By contrast, imposing the constraint that generation should match demand results in the lower peak generation shown in Figure 1.

Comparing the results of "financial" and "economic" studies gives Western an idea of the cost of the policy that isolates Western from market price excursions.

Many algorithms exist for minimizing the objective function of such complex systems. Linear programming (LP) dates from the 1940s and is among the most familiar of these. However, it is suitable only for particular kinds of problems; specifically, when the value of the objective is a linear function of the variables with linear constraints. Techniques were developed for addressing special cases, such as quadratic objective functions, but the kinds of problems that unadorned LP can address remains limited.

A particular attribute of the CRSP does not lend itself well to simple linear programming. Certain power plants incur significant startup cost and, once committed, may need to run at less than ideal efficiency. If they can make enough money over high-value hours, however, their operation can offset any losses due to their startup or operation during low-value hours.

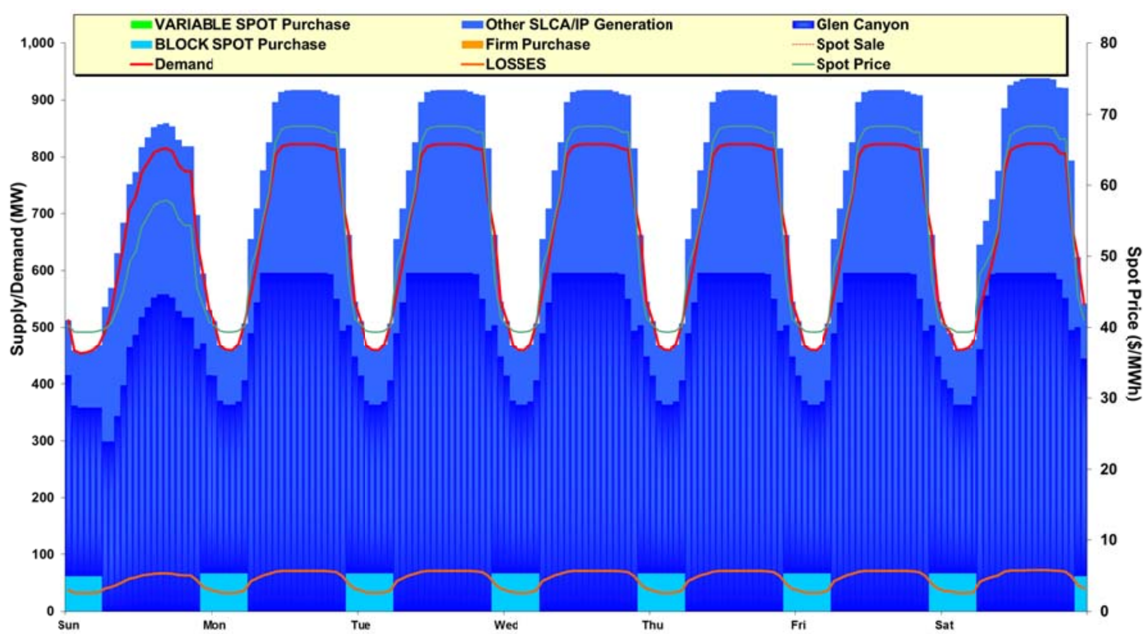

FIGURE 2: DISPTACH MAXIMIZES RESOURCE VALUE

[3] Source: Veselka, 2011, Slide 14.

The commitment of generating units is not a linear or even a continuous variable. The problem falls under the category of "integer programming" which seeks to minimize or maximize the objective function of integer variables; in this case, variables having only two values: 0 (not committed) and 1 (committed).

Mixed integer LP algorithms provide the capability to minimize costs when some of the variables are integers. GTMax uses the most popular mixed integer LP algorithm, the Lagrangian relaxation technique. As we discuss shortly, this algorithm is often used in power generation production cost simulation models for other purposes. For example, it can be used to find the least cost solution for security reserves commitment. GTMax, nevertheless, uses the mixed integer LP only for minimizing dispatch costs.

Finally, the topic of security reserves commitment is closely tied to the fundamental simulation period in this model. Dispatch commitments are made for the full hour. One hour is also the shortest time period the GTMax model "sees." This means that spinning and operating reserve for contingencies lasting less than one hour, sub-hourly load following, regulation capability, incremental and decremental reserves, and many other ancillary services are outside the scope of GTMax simulation and evaluation.

Solution period, state variables, and solution variables

Because the GTMax model can represent commitment of power generating units in certain hours to capitalize on opportunities in other hours, it is natural to ask over what period costs are minimized. For GTMax, this period is one week, which corresponds to a cycle for loads and market prices. It is typical to commit thermal generation on Monday morning for use over the weekdays. Wholesale power prices typically have their highest values during weekday on-peak hours. At the end of the workweek, these power generation units might be taken off-line to save money on the fuel that would otherwise be consumed to maintain the power plants in a standby mode.

However, the total cost is also affected by the initial conditions for certain variables, referred to here as "state variables." Attention must be given to how much energy is behind each of the dams and pumped storage facilities at the beginning of a simulation. At the end of each solution period, the model must perform necessary bookkeeping to assure that the initial conditions in the subsequent solution period are correct. Therefore, at the end of each solution period the GTMax model performs necessary bookkeeping.

Study period

Typically, analysts and decision makers are concerned with operation of the river over time periods of weeks to years. Seasonal effects and cycles in commodity prices and weather and probable changes in other future circumstances compel problem solvers to consider the long-term implications of short-term decisions.

When Western considers questions that extend from months to years, GTMax takes operation over the typical week as representative for the month. Consequently, 12 one-week simulations from hourly data comprise an annual study. For studies over multiple years these annual representations are taken from either continuous years or from years at regular intervals over the study horizon.

This approach is one of the standard techniques for reducing computational burden. Other models might elect to sample between three and eight hours in a day, but that approach sacrifices the ability to represent ramp rate and other dispatch constraints. As long as operation over all the weeks in a month is uniform and state variables are updated correctly, the GTMax approach should be reasonable.

Types of units represented

GTMax appears to have adequate representation for the kinds of generation in the CRSP system. It is not clear whether the model can represent the full complement of resource technologies in the WECC. There appears to be very little representation of energy efficiency or demand side resources beyond those that are captured through simple adjustments to hourly loads.

Transmission topology

Western has the capability to model transmission within its service area. GTMax typically represents the interface of Western with the rest of the WECC as purchases and sales of wholesale electricity at exogenous prices provided by the model user. The topology of the model is illustrated in Figure 3 below. As a practical matter, however, the topology in Figure 3 appears to be used infrequently at best in the studies conducted by Western and ANL. Instead, the default representation is simply a single price node representing the Palo Verde market hub where all purchases and sales take place. The ongoing usefulness of this simplified default representation was discussed at the workshop, and is addressed in more detail in the next section.

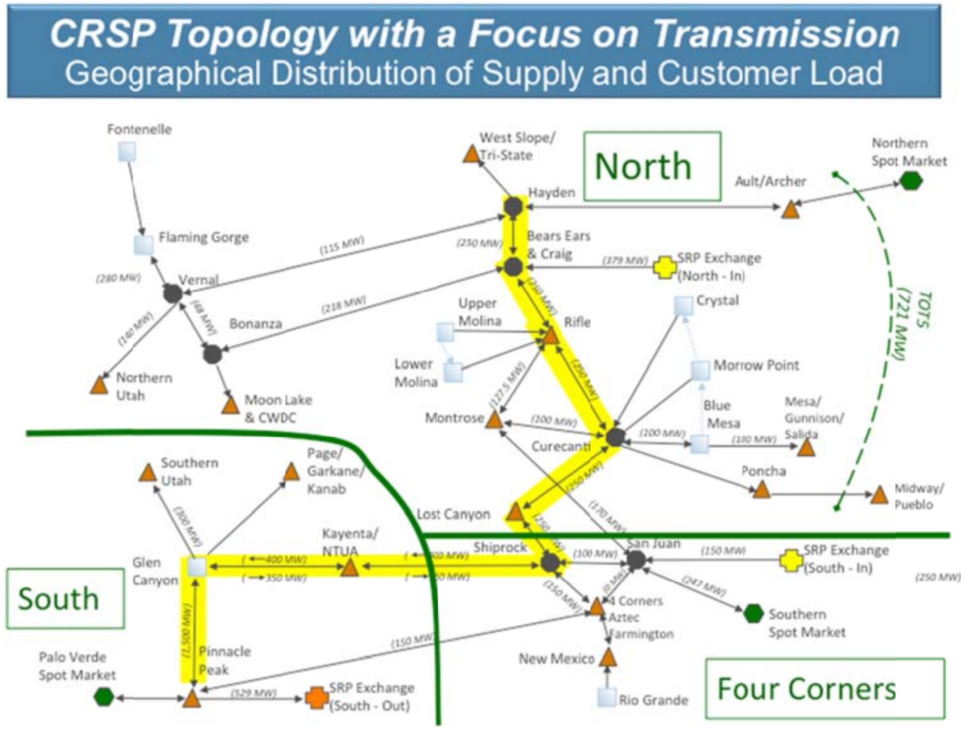

FIGURE 3: COLORADO RIVER STORAGE PROJECT TOPOLOGY IN GTMAX

Principal output

GTMax produces financial reports, which help dispatchers identify operational strategies to optimize the value of the system's resources. The model also allows users to define regions for added reporting capabilities. Data from GTMax are presented in tables and graphs, providing information such as which units should be dispatched, how much power should be generated and sold on an hourly basis, when to buy and sell power on the spot market, the cost of alternative power plant operations, the incremental value of water, and the value of demand-side management programs. GTMax also gives financial market clearing prices, which can be used to determine whether an investment is financially viable, given the prevailing market rules for bidding, capacity credits, and ancillary services.

Key exogenous data and constraints

The list in Table 2 identifies some of the key data provided to the model for a simulation. The amount and detail of data required by production cost models makes a complete description impossible. Nevertheless, certain data dependencies merit discussion.

TABLE 2: GTMAX DATA AND MODELING CONSTRAINTS

Key Input Data and Constraints
Electric Requirements including losses (loads)
Cogeneration thermal demand
Irrigation requirements
RiverWare forebay and stream inlet flows for alternate hydro conditions
Fuel prices, O&M, spot and forward prices for power market purchases and sales
Thermal start-up and minimum generation costs
Optionally, contract data for Western customer studies
Generating unit characteristics (e.g., heat rates, capabilities)
Constraints on unit ramp rates, stream and reservoir levels, stream and reservoir level rates of change, power transmission flows

Western relies on inputs from Reclamation's RiverWare model for hydrologic modeling. The general structure of RiverWare is described in Zagona, *et al* (2001). As we understand it, Reclamation uses this model to provide Western with forecasts of monthly water quantities available for discharge through the Glen Canyon Dam. Reclamation may revise these forecasts over the year as hydrologic conditions unfold. With a monthly water allocation as input GTMax then simulates operation of the Glen Canyon Dam and associated facilities according to various economic objectives and operational constraints. The economic factors that might affect the monthly allocation of water across the year are opaque. Casual observation of various GTMax results suggests that RiverWare has some notion that water is more valuable for power generation during the summer and winter months than during the spring and fall.

Western has also conducted studies that explicitly address hydrologic uncertainty. It is our understanding that in these studies, the complete hydrologic record is viewed as a probability sample from which representative elements are chosen to represent average, wet, and dry conditions. One example of this approach is discussed in Loftin (2011). This procedure ignores the possibility of climate change. Under a climate change hypothesis, some sample selection method would need to be used to determine a going forward relevant range of hydrologic variation that would be different, arguably drier, than what would be reflected using the complete hydrologic record. We discuss this point further below.

Typical Production Cost Model Features Not in GTMax

Table 3 lists important features found in many production cost models that are not contained in the version of GTMax reviewed at the workshop. These features are important in that they are necessary to conduct some of the types of analyses that Western is considering.

TABLE 3: PRODUCTION COST MODEL FEATURES NOT CONTAINED IN GTMAX

Capacity expansion algorithm	None-staged after WASP for certain studies
Reserves commitment algorithm	None-capacity de-rated for energy effects
Ancillary services algorithm	None-capacity de-rated for energy effects
Unit reliability algorithm	None-capacity de-rated for energy effects
Long-term risk algorithm	None-Users typically perform scenario analysis on hydro conditions, power prices

Capacity Expansion Algorithm

Many, but by no means all, production simulation models have the ability to add generation units within the study period, using an internal calculation. There are several reasons why this is valuable. Sometimes the question of generation capacity expansion is the central question. Utilities or marketers may want to know what kind of generation they need to add to their system in the future, and how much capacity that new generation should provide. Capacity expansion algorithms typically choose from a portfolio of resources and endeavor to find the optimal timing and sizing for each unit.

There are other reasons for having capacity expansion capability in a simulation model. Without such capability, simulated market prices for wholesale firm energy would reach unsustainable levels as energy requirements grew or fuel prices changed. These would become unsustainable because substitution effects (new generation, demand management, or economic curtailment, etc.) would prevail. Valuation of power plants without economic capacity expansion in this case would be invalid.

The proper valuation of capacity from generation is related to this issue. There are many different types of capacity and many different ways of valuing capacity. However, any kind of capacity will have values that vary with supply and demand over time. Estimating the capacity value without a well-established retail market is difficult and to some degree arbitrary.[4] This is illustrated below in our discussion of one Western/ANL study.

A significant advantage of a capacity expansion algorithm, however, is that endogenous capacity expansion will capture the changing value of capacity over time. This is a feature that many of the rules-of-thumb for capacity value, such as the construction cost of the simple cycle turbine, do not recognize.

Finally, while capacity expansion algorithms have significant advantages, most share one significant disadvantage. To minimize total costs over an entire study period, they must have perfect foresight of future commodity prices and loads. We return to the subject when we discuss long-term risk algorithms, below.

Reserves commitment and ancillary services algorithms

In the discussion of objective functions and state variables, we point out that GTMax fails to make commitments for security reserves, even at the hourly time step. Instead, GTMax de-rates hydroelectric generation capability to capture the cost to provide for these reserves.

The increasing importance of variable generation resources, such as wind and solar, have made ancillary services more valuable than ever. While it may have sufficed in the past to merely reflect the cost of producing these services for the native generation and load, it is becoming important to also estimate the ***value*** of these services for possible resale.

As previously noted, GTMax cannot simulate operational periods of less than one hour duration. There are other models that are capable of sub-hourly simulation. These models can value many kinds of ancillary services because they can simulate operation down to five-minute intervals. (Even these simulation models, however, cannot deal with regulation requirements that vary from second the second.) These models are often used to create better operating heuristics.

Depending on the specifics of turbine design, hydroelectric generation can have distinct advantages in providing ancillary services. It often can operate in a range where generation efficiency does not degrade. While almost all generation technologies will incur more stress and wear adapting to rapid changes in output, hydroelectric generation often incurs less operation and maintenance costs per unit of capacity than thermal generation. Often, the most significant cost associated with hydroelectric generation providing operating reserves is an opportunity cost. Incremental capacity for ancillary services requires units to reduce firm energy generation. Because incremental operating reserves are often most valuable during on-peak hours, on peak firm energy is effectively shifted to off-peak hours, when it is less valuable.

[4] Capacity valuation cannot truly be made in the absence of some estimate of consumers' "value of lost load."

With Western and the WECC entering into a period of increasing generation from renewables and therefore also possibly the need for ancillary services, the absence of ancillary service valuation capability is conspicuous. While GTMax would not necessarily have to be modified to provide Western and its constituents with this value, some valuation mechanism is certainly necessary to studies Western will be performing.

Unit reliability algorithm

Many production cost models provide detailed simulation of unit forced outages. The NERC Generation Availability Data System (GADS) database provides operating history for units in the United States and abroad. The history contains important reliability data, such as mean time to failure and mean time before recovery for classes of generation technologies. Simulations of energy generation and cost are more meaningful if they recognize unit forced outages. Such simulations, for example, reflect the consequences of relying on a single, large power plant versus an ensemble of smaller, independent plants.

An alternative to the detailed simulation approach is capacity deration. This is the approach adopted by GTMax. The capacity deration method assumes that there are a sufficient number of small contributions in an ensemble of generating units that the system as a whole is quite reliable. That is, the distribution of energy produced by the ensemble is narrow and has a mean value close to the capacity at ensemble, discounted by the average amount of energy that would become unavailable due to forced outages.

The capacity deration algorithm is quite helpful in situations such as the modeling of market prices at trading hubs in the WECC. None of the units in the WECC, except perhaps the nuclear units, impose significant individual risk. Since one of the assumptions is that all of the forced outages are independent, there should be small forced outages occurring almost continuously with an average effect that closely approximates a de-rating of capacity.

For studies of the revenue impacts of Glen Canyon and Hoover dams on Western, however, we need to reconsider this assumption. These two facilities have considerable generation capability relative to Western's requirement. Units associated with the dams have considerable common risk. For example, the failure of a substation transformer or transmission line at one of the dams takes out the entire project. We therefore question the application of capacity de-rating for modeling forced outages in representing Western's system.

Long-term risk algorithm

Utility planners often deal with risk by using two separate processes. For short-term variation in commodity prices, an anticipated level of unit forced outages, and the impact of weather variation on loads, planners use what they would call stochastic modeling. They often describe distributions using historical data. Typically, they tie their mean reverting stochastic processes to a single, underlying benchmark forecast. For long-term risk, to which they invariably refuse to assign probabilities, planners use scenarios.[5]

GTMax has little short-term risk simulation capability and virtually no long-term risk simulation capability. Nevertheless, Western and ANL have introduced some long-term risk analysis by the use of hydro-electric generation condition scenarios and power price futures. These, however, are mean-reverting processes that tend to understate risk.

Another limiting factor is the perfect foresight and perfect information usually implicit in commitment and dispatch. Operators never misjudge the weather or fail to anticipate fuel and power price excursions in such models. This deficiency in GTMax is shared by almost all production cost simulation models. Models often need perfect foresight to arrive at solutions for capacity expansion and dispatch. Perfect foresight precludes any consideration of significant risk. We return to a discussion of the perfect foresight assumption later in this report.

OBSERVATIONS AND FINDINGS

This section of our report details particular issues considered important to the future and ongoing use of GTMax. In some cases, they lead to recommendations that are elaborated in the concluding section.

Energy Market Prices

For historical studies based on "economic modeling," ANL and Western rely on actual daily prices at the Palo Verde hub. These prices reflect bilateral trades, rather than organized markets, and are not typically available on an hourly basis, which is the time step for GTMax dispatch simulation. Therefore, some processing of the available data is required. This is discussed in the ANL report on the Post-ROD Analysis in Sections 3.4.1, 3.4.2 and 3.5.2 (Veselka *et al*., 2010).

For "financial modeling" studies, ANL and Western rely on the actual prices paid by Western. Actual and historical daily prices differ because Western hedges the large majority of its load with contracts, so as not to be exposed to the volatility of daily prices. There can be substantial differences between the actual Western contract prices and the daily prices. This is illustrated below in Figure 4 (Veselka, 2011, Slide16).

The "spiky" pattern in Figure 4 reflects daily price volatility. The contract price path exhibits "step-wise" discrete changes, reflecting the more stable pricing of contracts, whose price duration

[5] The form of scenario analysis popularized by Pierre Wack, Royal Dutch Shell's London headquarters, in the 1970s also ignored probabilities. The purpose of their exercises, however, was to raise consciousness about potential, large-scale changes in their industry. Like a good military planner, Wack encouraged management to develop various contingency plans to implement in the event that one of these futures would come to pass.

exhibits varying length, and changes in level reflecting newly purchased blocks of contract power and the expiration of previous contracts. Just after the California energy crisis of 2000-2001 there was a huge mismatch caused by Western's hedges that were purchased just before the pricing distortions in the daily market disappeared. Other market participants, such as the California Department of Water Resources, experienced similar if not worse problems of this kind at this time.

There are several issues associated with using Palo Verde prices. First is the question of whether these prices are invariant to the policy and dispatch changes that Western is examining in its historical studies. All of the economic studies assume the same prices regardless of operational changes at the Glen Canyon Dam. The underlying assumption is that whatever changes might possibly occur, they are too small to matter given the large size of the market. This assumption may probably be true, but it is an assumption that should be examined. Second, for forward-looking studies the historical data may not be useful.

Western and ANL are proposing that an enhanced GTMax topology, based on the entire WECC region be used to address both of these issues. Given the computational complexities associated with a "full" representation of WECC, the proposed configuration would use 23 "zones" to model the regional market. ANL has used such a representation in studies conducted on behalf of the US Department of Energy. Other simplifications to the modeling would also be necessary.[6] The underlying assumption in this proposal is that simulation modeling is the preferred way to study pricing.

[6] Without going into too much detail, one important issue involves how the enhanced presentation would handle the commitment of thermal generators in the region. GTMax can represent thermal unit commitment in "small" systems by doing an exact calculation. For large systems the exact solution is unwieldy. Proprietary commercial production simulation models use various approximations and heuristics. The effect of this issue on the estimation of market clearing prices can be significant. There is an extensive discussion of these topics in Kahn (1995).

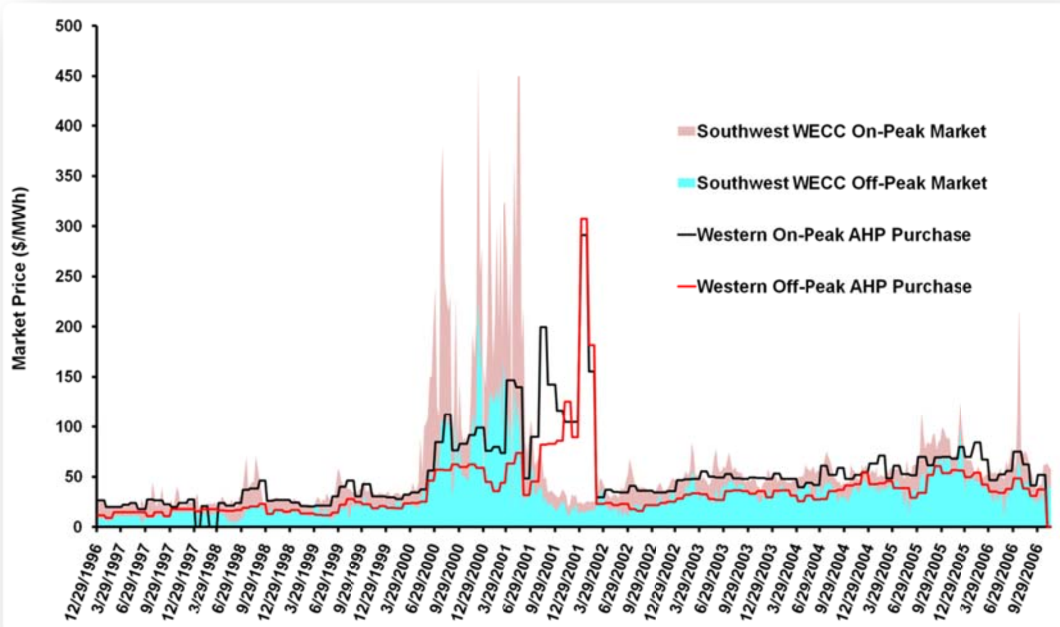

FIGURE 4: SOUTHWEST WECC AND WESTERN PURCHASE PRICES

An alternative approach to understanding prices at Palo Verde, or any other electricity market hub, is based on econometric methods. When applied to market processes econometric models are statistical representations of market prices based typically on a linear relationship between independent drivers of an economic price formation process and the resulting observed price. Barmack et al. (2008) model day-ahead on-peak prices for the 16-hour daily peak period at Palo Verde and the Pacific Northwest Mid-Columbia hubs. They use the daily spot natural gas price, nuclear plant availability, and regional loads as the independent explanatory variables that produce the observed electricity price. In the Palo Verde models, the role of the California market is examined closely, and measures of transmission congestion between California and Arizona are also introduced. The congestion measures improve the performance of the model. One result the authors find is that at the Palo Verde hub, the availability of an additional 1000 MW nuclear unit leads to about a 2% drop in price. This paper uses hydrologic variables in the models of the Mid-Columbia prices, since hydropower is so important in the Pacific Northwest. No hydrologic variables are used in the Palo Verde models. Woo *et al*. (2007) is another paper of this type focusing on the Pacific Northwest.

Econometric models are not a "magic bullet" in that they can have significant issues and result in imprecise estimates. Their advantage is that they incorporate the statistical distribution of observed prices within the model. This contrasts with the "point-estimate" approach described above for Western. The relevant question is whether they do a better or worse job at estimating prices than production simulation models. Arnedillo (2011), in a context assessing market power in electricity, argues that the perfect information assumption of production simulation models and other simplifications make them poor predictors of electricity market prices. We will return to this topic when we make recommendations.

Transmission topology and the WECC

Transmission plays a vital role in power systems. Transmission congestion is said to occur when the demand to move power from one part of the grid to another exceeds system capacity. In electricity markets transmission congestion means price separation between the low price export region and the higher price import region. The Glen Canyon Dam is located in a region that primarily exports power to the west. So if congestion occurs east to west, then the price of power from the export zone declines compared to the price in the import zone.

GTMax has the capability to represent the network topology of the CRSP region. Figure 3 above illustrates this representation. Most studies by western and ANL using GTMax do not use this topology. Instead they assume that there is never any transmission congestion, so one price is good for all power produced in a given hour. Absent this assumption, then congestion would produce different prices for Glen Canyon Dam output and power at Palo Verde, or other locations in the CRSP region. The only study described at the workshop using the network topology of Figure 3 was a “financial” analysis for all Western customers, and it used contract prices, which are presumably constant whether congestion occurs or not.

Ancillary Services

Ancillary services refer to specific electricity products traded in formal electricity markets to maintain system reliability in the face of potential disturbances. Some of these services provide very short-term energy balancing to maintain system frequency in its prescribed bounds. This is usually called “regulation.” Other products are reserve capacity that can be available on very short notice to meet unexpected conditions that may arise. Spinning and non-spinning reserve are two such products. All of these functions are self-provided by utilities engaged in traditional scheduling. In formal markets these services are unbundled, procured by the ISO/RTO, and priced through auction mechanisms. Each service has different costs, typically opportunity costs that must be weighed against their value as reflected in the market price.

We have previously asserted both that hydro-electric generation is particularly well-suited to provide ancillary services and that the demand for these services is likely to increase as the power system relies more on variable sources of generation, particularly wind generation. Both points are well illustrated by the recent evolution of the electricity industry in Spain. The Spanish power system has been operating as a formal market since 1998. Policy initiatives to encourage wind generation in Spain have been quite successful. By 2003, about 5% of electricity generation came from wind. By 2010 the share of wind generation had risen to 16%. Between 2003 and 2010 demand increased by a bit more than 20%. The demand for ancillary services doubled during this period. The increase in wind generation is the main cause of the increased demand for ancillary services. Hydroelectric generation capacity is currently about 17% of the capacity in Spain. For some of the reserve services, hydroelectric generation capacity provides more than half of the demand.[7] For most of these services, hydroelectric generation has a share much greater than 17%. There is nothing so unique about the Spanish market that would prevent the same factors from playing out in the WECC region.

Capacity value—lack of conceptual clarity

Among the more confusing topics in electricity economics is the notion of capacity and its value. Electric energy is a straightforward and familiar notion. Capacity, on the other hand, is the instantaneous ability to produce power, but not the power itself. In most of the ISO/RTOs there are "capacity" products of different types. Some markets include payments for "Installed Capacity," adjusted typically for its reliability. Most markets also make payments for ancillary services capacity. These payments are typically based on the results of an auction process. In the case of ancillary services, what counts for capacity is the ability of generators to adjust output and respond in fairly rapid (i.e. sub-hourly) timescales. These are different, indeed much lower numbers, than what would count for installed capacity. Furthermore, different generating technologies are very different in how much and how quickly they can change output levels. For reasons such as these, some analysts find that using the same word "capacity" for these different functions isn't helpful. The Pacific Northwest Utilities Coordinating Council (PNUCC), for example, has a recent white paper on this topic where they propose to rely on the term "capability" as an alternative (PNUCC, 2011).

In economic studies, it is often necessary to take account of "capacity" effects. In most cases, the context of the study will provide some indication of what is meant by the term, but not necessarily complete clarity.

One example of this ambiguity arose in the workshop discussion of the Post-ROD analysis. There was a numerically important effect of a high value proxy chosen for capacity cost in that study. ANL presented a sensitivity analysis on 1 September that showed capacity costs dominating energy costs after the California Energy Crisis effects on energy prices were removed (Slide 14 vs. Slide 12)[8].

Table 4 shows a menu of choices for capacity values in one ANL spreadsheet file.

[7] The factual basis of this discussion is documented in the various reports of the system operator in Spain, Red Electrica de Espana (REE). Their Annual Report provides data on installed capacity, energy production and ancillary services among other things. These reports are available at: http://www.ree.es/sistema_electrico/informeSEE.asp. For 2010 data on ancillary services, see REE (2011).

[8] Veselka (2011) slides 12 and 14. Table 4 has been reproduced (copied) from the slide version.

TABLE 4: WESTERN CAPACITY REPLACEMENT SHEET

GCD EIS MLFF Scenario	*Replacement*	*Coal*	*NGCC*	**Technology**
	74	1,511	633	**Capital Cost ($/kW)**
	1991	2004	2004	**Capital Cost Base Year**
	1	0	0	**Unit Capacity (MW)**
	1.25	10	10	**Discount Rate (%)**
	1	40	30	**Technology Lifetime (yrs)**
	2000	2000	2000	**Year Constructed**
	0	25.07	10.65	**Fixed O&M cost ($/kW)**
	2009	2009	2009	**New Base Year**
Capacity Replacement (DH) (use for woROD scenario)	*Gas Turbine*	*Coal*	*NGCC*	**Technology**
	424	1,511	633	**Capital Cost ($/kW)**
	2004	2004	2004	**Capital Cost Base Year**
	-524	277	0	**Unit Capacity (MW)**
	10	10	10	**Discount Rate (%)**
	25	40	30	**Technology Lifetime (yrs)**
	2000	2000	2000	**Year Constructed**
	9.59	25.07	10.65	**Fixed O&M cost ($/kW)**
	2009	2009	2009	**New Base Year**

It is our understanding that ANL used the natural gas combined cycle (NGCC) option to value the capacity changes associated with the post-ROD scenario. Clearly they recognize that other values could have been used. Choosing the "replacement" value of $74 per kW would have changed the conclusions of the Post-ROD study substantially. It appears from

Table 4: Western Capacity Replacement sheet that the low capacity value was used by Western in some of the studies discussed in Loftin (2011), where the MLFF Scenario, for example, was modeled. At a minimum, some discussion of the reason for choosing particular values for one study versus another would be desirable.

RiverWare

Water flow is the critical input to the ability of the CRSP facilities to generate enough electricity to both meet native load and have sufficient energy to participate in developing WECC markets. The use of RiverWare then is, or should be, subject to scrutiny along with the GTMax model. RiverWare is itself a combination simulation and optimization model with many user-specified options as to modeling approaches and algorithms that may be employed to model the water flow in a particular basin. Physical processes in question are modeled according to specific algorithms or methods the user may select based on time step size, data availability, desired resolution, or institutional need. For example, each of the power generation, tail water calculation, and reach routing processes may be modeled using up to six different methods. For the RiverWare output used as input to the ANL modeling the combination of methods actually used is unknown. Furthermore, there may be disagreement over specific methods applied to particular basins. Beyond hydrologic questions about the appropriate modeling of river basins lie the questions of long-term climate change that may have dramatic effects on water flow and on competing uses for water. Models populated using historical data may be inadequate to address the full range of these potential effects. Indeed, recent experience indicates that competition for water is intensifying in the desert southwest and that its supply has been below historical levels; this competition must be considered in development of long-term plans for water use.

Large-Scale and Long-Term Risk

The CRSP faces significant strategic risk in the form of potential climate change, diversions from the river, increased summer temperature and penetration of air-conditioning, new legislation, changes in market structure, the regulation of fuel sources, carbon emission penalties, and technological innovation. These would directly or indirectly affect river and stream flows, customer requirements, fuel availability and prices, market prices for wholesale energy and ancillary services, availability and value of particular resources.

The GTMax model and Western's analytical framework is designed primarily to evaluate short-term operations. The authors of GTMax excluded long-term planning features, like long-term capacity expansion capability. One of the key input data sources for GTMax is the hydro-electric generation provided by the RiverWare model. As mentioned in the previous section, Western takes these data from Reclamation and therefore is not situated to modify hydro-electric generation for climate change or river diversion studies. The design does not facilitate convenient or efficient evaluation of alternative assumptions and futures. The model does not have the geographic scope to study the possible consequences of policy changes in other parts of the WECC.

The GTMax model performs well the jobs for which it was designed, i.e., assessments of short-term operational trade-offs. It may well be impractical or even counterproductive to design a model that handles both short-term operation and long-term risk assessment. Nevertheless, long-term risks assessment and management are important missing pieces of the planning Western should be performing.

Economic and Financial Studies

The sections Objective function, solution algorithms, fundamental period, and Energy Market Prices above, describe the distinctions that Western draws between "Financial Studies" and "Economic Studies." These differences are primarily in the treatment of loads and prices for purchased power, both market and contract power.

Western appears to be conflating its evaluation of market exposure risk with financial reporting, especially in its treatment of load. The load following that Western illustrates in Figure 1 for its Financial Studies and the prices that they adopt for these studies are characterized as required for rate analysis and reporting purposes. These conventions are outside our experience with other power industry agencies and companies. We do not understand them and suspect that they may be reaction to events that proceeded from some market exposure during the energy crisis.

More standard language would help Western be more effective in communicating analysis and results with stakeholders and customers.

The User Community and Process Issues

Western uses GTMax for daily scheduling and for special purpose studies that examine various policy choices. For policy analysis it is important that stakeholders understand the modeling process and the choices made in performing particular studies. If the modeling process is perceived to be a mysterious "black box" then acceptance of results is impeded. One purpose of the workshop was to improve transparency so that stakeholders can contribute in a meaningful manner to future policy discussions.

It is an open question as to exactly what level of transparency is appropriate. At one extreme, one might imagine that particular stakeholders would run the model themselves to examine cases of interest to them. This is probably exaggerated. The costs of such an alternative would be high in both time and resources (stakeholders might need to use consultants to achieve the goal of independent modeling). One intermediate option would be to find a way to make modeling results more understandable to stakeholders than is presently the case. It is often the case that one or two critical assumptions determine the qualitative features of studies on a given topic. When the choice of such critical inputs is subject to ambiguity, it can be useful to focus stakeholder discussion on that choice. One example illustrated in our review, and discussed above, is the choice of capacity value.

It can be challenging to determine *ex ante* what the critical input assumptions are in a given case. One way to aid the process of knowledge generation by stakeholders is to make diagnostic reports available. Then anomalous or otherwise troubling results can be traced back to particular assumptions or calculations. We had no discussion at the workshop of the extent to which GTMax can generate diagnostic reports. Most commercial models have this capability. It should not be too difficult to add this capability if it does not already exist. Similarly, written documentation of the GTMax model would be useful. This topic was discussed at the workshop, but we have not seen anything beyond what was presented and provided by the speakers for the workshop.

Non-power values: reducing these to hydro constraints is the best that it can do.

Finally, it should be clear by now that GTMax functions in a limited domain of the analysis space that may be of interest to the GCDAMP. Many questions of interest can be examined through the GTMax lens if they are formulated in a way that the model can handle. In practice this will amount to running sensitivity cases where policies of interest are reduced to constraints on the operation of the GCD. The problem formulation and specification will occur outside of the model, guided by the knowledge and perspective of stakeholder groups.

CONCLUSIONS AND RECOMMENDATIONS

Anticipated operations and modeling implications

Western may want to consider developing the conceptual framework and quantitative tools to better prepare for its participation in ancillary services markets. It is fundamental to have a clear understanding of what these services are and from where they derive their value. Western may or may not already have this understanding. What is evident, however, is that there is no consensus on these concepts or their valuation among stakeholders and observers. The lack of clarity and lack of consensus on capacity value is one example.

Having built consensus understanding, Western should evaluate their participation in ancillary service markets. Even if participation in formal markets is not an objective that stakeholders share, Western nevertheless needs to value the services. Western stakeholders and customers need to understand the tradeoffs that they are making in electing to participate or to refrain from participation in these markets.

It is also right and proper for Western to investigate opportunities presented by its geography, that is, the capability to bid into CAISO markets and enter into bilateral contracts with other entities. For example, Western should investigate energy arbitrage between day-ahead and real-time markets. Western, its customers, and its stakeholders may conclude that pursuit of such opportunities is imprudent. Nevertheless, they again need to know the tradeoffs these opportunities present in terms of rewards and risks. Consequently, they need appropriate tools to perform such studies.

This leads to our recommendations about transmission topology and modeling the interface with the rest of the WECC. This is clearly an area that needs enhancement. Western needs to be able to assess both the short-term and long-term effect of actions by Western and the rest of the WECC on each other. We believe that there are adaptations that would not require Western to abandon GTMax. It may be possible to perform special studies using other, more extensive models to develop rules of thumb and qualitative understanding of the impact of particular actions. As explained in the next section, it may be possible to develop econometric models that capture some of this interaction.

Econometric model of Palo Verde Prices

Palo Verde energy prices play a critical role in the use of GTMax. One strength of the current modeling framework used by Western and ANL is that it avoids relying on the model to predict prices. For various future purposes, Western and ANL have proposed enlarging the geographic scope of GTMax to all of WECC. This approach would inevitably result in relying on the model to predict price. Such a step should be viewed cautiously. Models typically calculate price as the marginal cost of production. While price is typically related to the marginal cost of production, it is not necessarily identical to it. This is relevant to our discussion of cost-based versus value-based compensation earlier in the report. Exploring an econometric approach to Palo Verde pricing is a potential alternative that deserves serious consideration. For many business purposes, Western needs to understand price formation at Palo Verde. Econometrics starts with the actual price data, seeking to explain the variations in observed prices. Econometrics is an imperfect tool, like all other tools. Expanding the toolkit, however, is often worthwhile.

Long-term, large-scale risk and modeling implications

In our considered opinion, GTMax is not the model, nor is Western the sole organization to investigate long-term, large-scale risks. The uncertainties include climate change, technology innovation, or market and regulatory changes that could affect wholesale power prices and the price and availability of fuels. If GTMax is to play a role in a more comprehensive framework for study – an outcome we would not dismiss – GTMax needs to be augmented. Either the RiverWare model or other models to create hydroelectric generation input data must be brought in under the framework. Tools for evaluating capacity expansion are necessary. The framework needs to make efficient and thorough assessments of large-scale, irreversible changes in future conditions.

Perhaps the most effective and efficient piece to the solution is a more open process around the kinds of scenarios that Western examines. We believe it is necessary to give more complete consideration to contingency plans and to scenarios where circumstances do not play out according to assumptions. Studies need to reflect that circumstances can change at any time and typically cannot be anticipated. When Western learns of a new development, others will have as well, and measures to mitigate the outcome will already be priced in the market. Buying homeowner’s insurance when the house is on fire is difficult and expensive. Contingency planning is therefore central to risk mitigation.

Western and ANL staff and stakeholder participants are important sources for the experience, knowledge, and creative energy to address risk. However, Western’s purpose, marketing power, is less than a perfect match for a long-term stewardship role implicit in long-term risk management.

We do not have a recommendation about which group or agency should assume this role, but it does bring us to our last recommendation.

The User Community and Process Issues

At several points in this report, we have pointed out the important role the stakeholders play in the credibility and value of Western studies. The section **The User Community and Process Issues** recommends particular modeling enhancements that could make studies more accessible by participants and observers.

We need to emphasize that we believe there are situations in which outside observers and experts can bring more value to policy analysis than modelers. Treatment of strategic risk, for example, is often a question of analytical vision and discipline rather than computational horsepower. A forward-looking analysis of potential climate change effects would be much more credible, for example, if the hydro scenarios were structured by climate experts rather than simply chosen by modelers.

In any case, consensus on language and methods, and access to the models and their results is key to the credibility of any study. By consensus and access, here, we refer not only to consensus within Western and ANL and physical access to reports, but practices that make the studies and their recommendations transparent to all stakeholders and observers.

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