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]

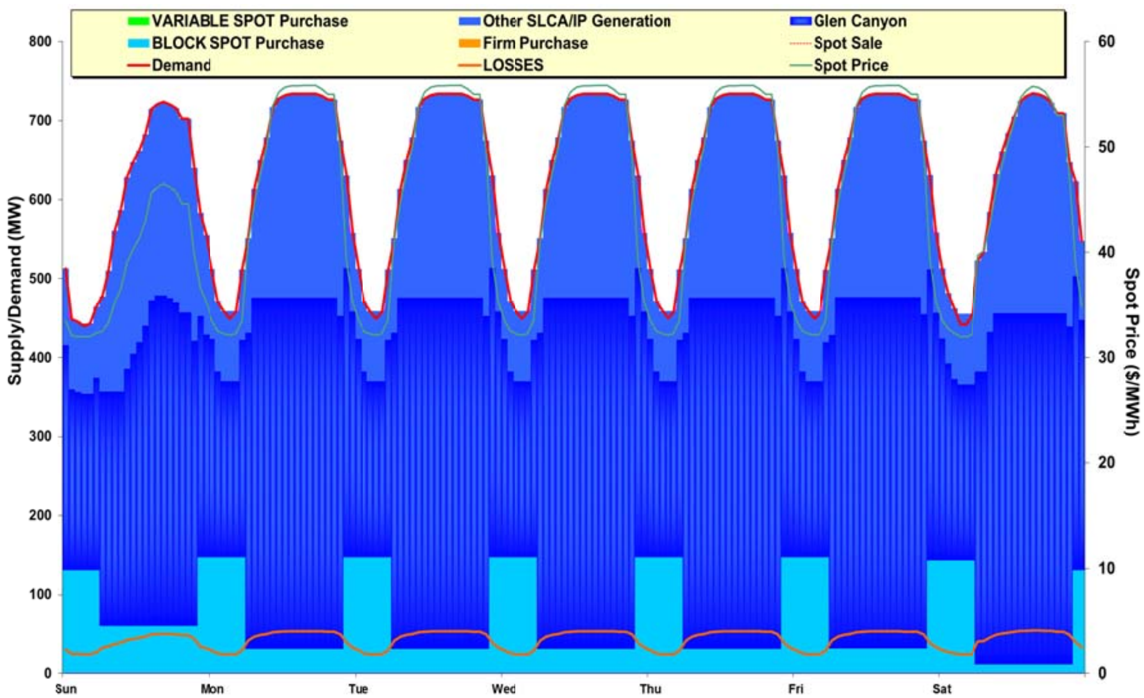

FIGURE 1: DISPATCH FOLLOWS CONTRACT LOAD

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.

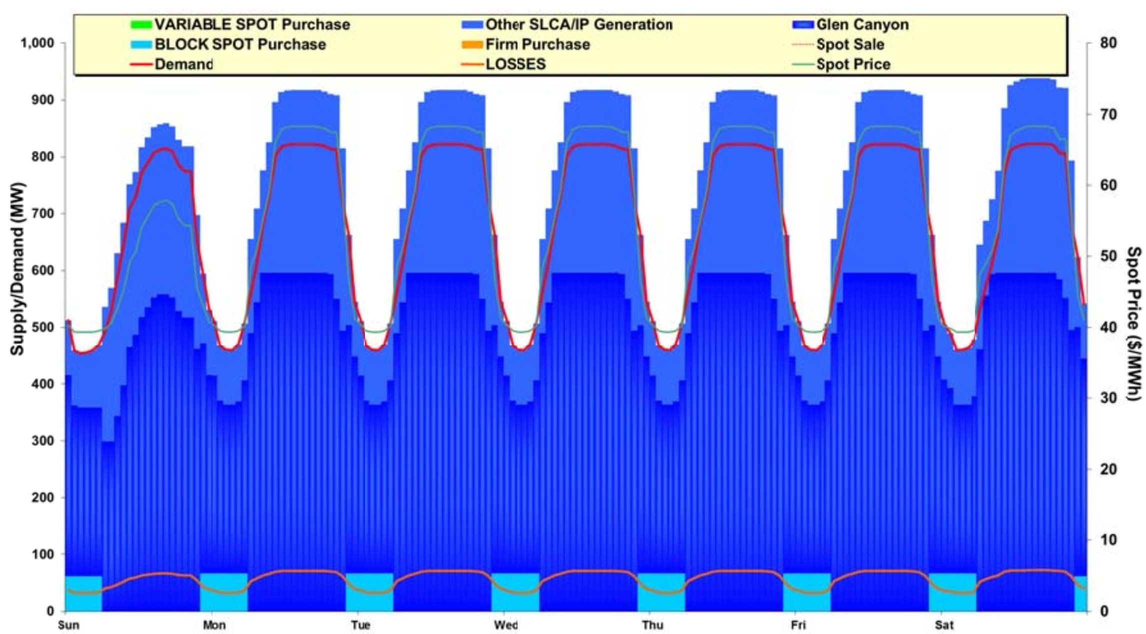

FIGURE 2: DISPTACH MAXIMIZES RESOURCE VALUE

[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.

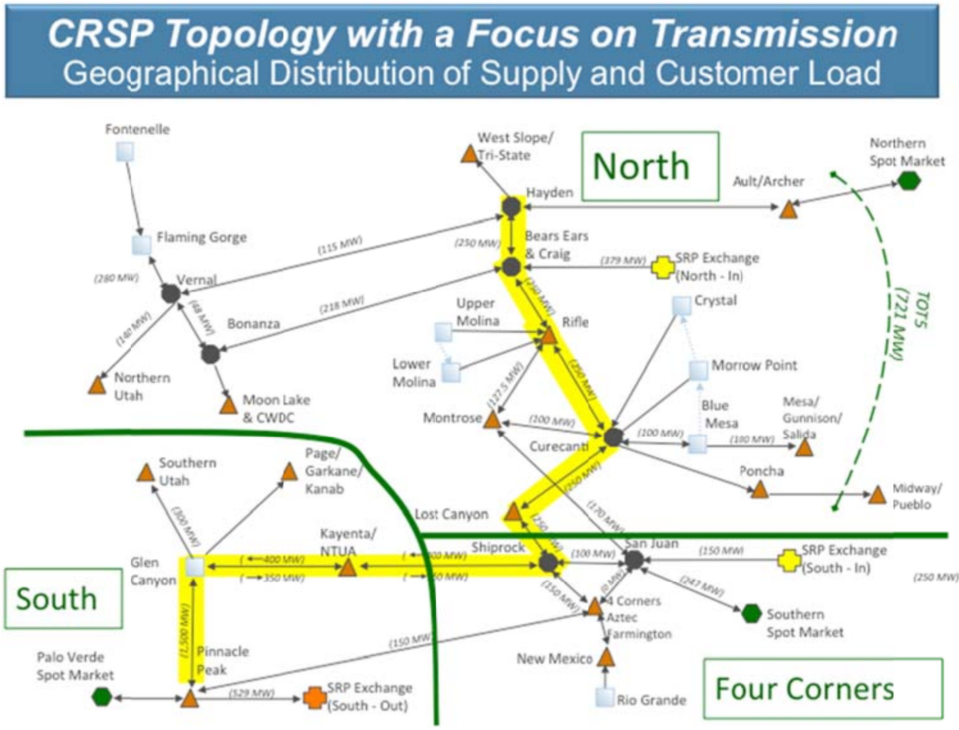

FIGURE 3: COLORADO RIVER STORAGE PROJECT TOPOLOGY IN GTMAX

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.

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[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).

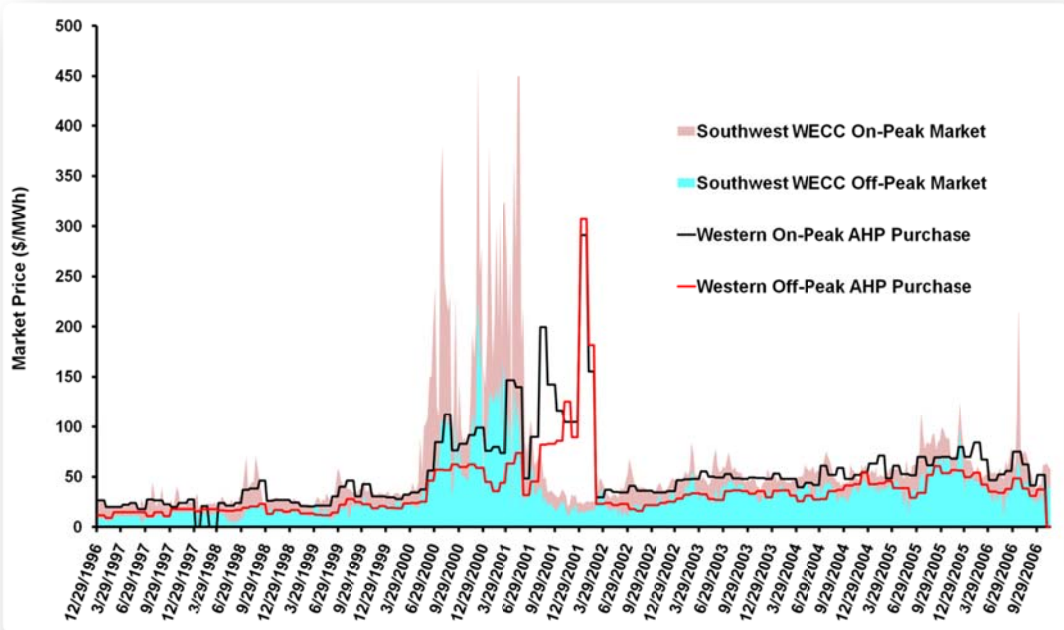

FIGURE 4: SOUTHWEST WECC AND WESTERN PURCHASE PRICES

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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Comments by S. Clayton Palmer
on the
FINAL REPORT OF THE GTMAX MODEL REVIEW PANEL:
Report of a Workshop held August 31 and September 1, 2011 in Flagstaff, Arizona
Draft of Tuesday, September 04, 2012

Background Information

In recent years, the Glen Canyon Adaptive Management program committees, specifically the Glen Canyon Adaptive Management Work Group (AMWG) and the Technical Work Group (TWG) have been interested in an expanded and more transparent program of gathering and analyzing economic data related to the operation of Glen Canyon Dam (GCD). The purpose of these committees is to make recommendations to the Secretary of the Department of Interior (DOI) regarding the operation of this dam. Economic analysis is key to making informed recommendations.

In order to begin the development of this expanded economic program, the Grand Canyon Monitoring and Research Center (GCMRC) convened a workshop on behalf of the TWG that included a panel of economists This workshop occurred in December, 2009. The economic panel prepared a report with a set of recommendations. Subsequently, the TWG established a subcommittee to review the recommendations of this panel and make its own recommendations regarding implementing the panel's report: the Socioeconomic Ad Hoc Group (SEAHG).

Western Area Power Administration (Western) sponsored the development of a simulation model – the GT Max – as a representation of the production of hydropower in the Upper Colorado River System. The model was developed by Argonne National Laboratory. The model had two purposes: to assist Western in making its operation of the CRSP powerplants more efficient, and to estimate the electrical power production impacts of different operational regimes. For the latter purpose, the U.S. Bureau of Reclamation has also made use of the GT Max model – specifically for estimating the impact of proposed changes to the operation of CRSP powerplants in environmental planning documents.

The purpose for my recitation of this history is to explain why the GCD adaptive management program has taken an interest in this model. At one of its recent meetings, the AMWG recommended that Western use the GT Max model for evaluating the electrical power system impacts of proposed changes in GCD operations. The GCMRC, the AMWG and TWG became interested in considering the suitability of the GT Max model: is it a suitable model – properly specified and sufficiently robust – to address the information needs of the stakeholders?

The purpose of the GCD AMP's interest in considering the GT Max model for estimating the economic impacts on the electrical power system should be made clear. The GCD AMP program requires information on the economic impact on the electrical power system, along with other economic data and analysis, in order to make recommendation on the operation of the GCD. The SEAHG, following up on its task to consider the economic panel's report, prepared its recommendations. These were adopted by the TWG and AMWG[1]. The information required is economic valuation of proposed changes to GCD operation – one component of which is in regard to the use values related to electrical power.

[1] *RECOMMENDED INFORMATION NEEDS AND PROGRAM ELEMENTS FOR A PROPOSED AMP SOCIOECONOMIC PROGRAM*, APPROVED BY AMWG, FEBRUARY 23, 2012

The GT Max Panel Report

As reflected by the subject report, the GT Max review panel appears to have a set of objectives that differ from the information needs of the GCD AMP. In addition to a review of the GT Max model, the panelists provide a set of recommendations related to improving Western's position in the electrical utility industry [page 30]:

> *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*.

In addition to advocating that Western modify its position vis-à-vis real-time markets, the panelists propose that Western participate further in ancillary service markets [page 29]:

> *Western should evaluate their participation in ancillary service markets*.

Moreover, in various places throughout the report, the authors suggest that Western should seek to improve its <u>profit</u> position, increasing net revenues by bidding its generation into California's ancillary services market.

Not only do these recommendations seem to have little or no relationship to the goals of the GCD AMP, it crosses from positive analysis to normative analysis. An advocacy of a modified set of operating policies and legal framework seems foreign from an advocacy of unfettered and objective scientific inquiry. It further indicates a panel that is unfamiliar with the legal framework in which GCD electrical power is marketed.

Another important mistake of the panel's report on the GT Max model is this: the GT Max model is routinely used by Western to estimate the impact of short-term experiments, to provide an indication of direction and magnitude of a proposed GCD operational change where an impact is required quickly or to evaluate existing scheduling practices. The presentations made by the GT Max model creators and users during the workshop were geared to explaining these routine uses. As a presenter, I could have explained how the GT Max model might be reconfigured to address the issues in the panel report. After all, the GT Max model has been used to model substantially larger electrical systems, both in geography and in type, than the CRSP power system. [2] Questions related to how the GT Max model – a production cost model – might fit into a process of a more geographically or temporally robust framework was not discussed during the workshop. In this response to the panel report, I will attempt to illustrate an example of how this has been done.

The GT Max Model and the GCD AMP Relevant Questions

The relevant questions for the GCD AMP, its committees, stakeholders and the GCMRC is this:

- For developing economic analyses of the electrical power system, can the GT Max be a useful tool and/or how should the GT Max be configured and calibrated, what data should be used as inputs and

[2] I will go into more detail about this subject in subsequent pages.

how should the GTMax model outputs be evaluated to develop scientifically adequate analysis to meet the information needs of the GCD AMP?

Economic use Values for the Electrical Power System

The determination of economic use values for the electrical power system for changed operations at the GCD requires the following:

- The identification of the relevant market.
  This issue appears to be elusive and has been considered (or ignored) over several years. In order to determine the economic value of a good or service, the market within which the good or service is produced and consumed needs to be identified. In the current context: is electrical production at GCD exchanged and consumed within a North American market, within the "western grid" or is production, consumption and exchange confined within the CRSP system and the electrical systems to which it is directly tied?

"Everything affects everything else" is an oft used phrase. Never-the-less, everything doesn't affect everything else in equal proportions and some effects are irrelevant or inconsequential. In the December 2009, economic panel report, the economists that served on that panel were also interested in establishing economic values for use in evaluating changes in operations at Glen Canyon Dam. They were well aware that an electrical "grid" exists in the Western United States. As they noted[3]:

> *[the] GCD and the CRSP system are embedded in the larger western power grid (the WECC). Similarly, the utilities to which CRSP sells power are embedded in the WECC. Therefore, in principle, the market by reference to which the economic value of GCD power is determined is not the CRSP system but the WECC. At any point in time, it is the marginal price of electricity in the WECC that determines the economic value of power generated at GCD.*

However, the panelists also suspected that the electrical power output of GCD is small relative to the total electrical capacity in this "grid". The panelists suggested a study to determine the extent to which a change in the operation of GCD "spill over" into the WECC "grid". The proposal from the panelists is as follows:

> *Given the alternatives, existing models used by WAPA to optimize the operation of the integrated system of generation resources should be used to determine if all consequences of changed operations can be managed within the WAPA marketing area, or if electrical (and thus economic) "spill-over" effects will alter generation patterns, market prices or transmission bottlenecks elsewhere in the WECC system. If the effects of changed operations at Glen Canyon can be managed by WAPA without economically significant changes in the rest of the western U.S., then the economic consequences of such operations will be limited to WAPA's customers, and the modeling effort limited.*

The logic is this; if the electrical production at Glen Canyon Dam is "small" relative to other resources in the western electrical grid, a change in its operation will not affect exchange rates (prices) in the

[3] *Final Report of the GCMRC Socioeconomic Research Review Panel Report of a Workshop held December 2 & 3, 2009 Phoenix, Arizona*, Hamilton, J, Hanemann, M., Loomis, J., & Peters, L., Grand Canyon Monitoring and Research Center, February 26, 2010

WECC system. If this is the case, then the so called "WAPA models" that are configured for the CRSP electrical system and its contractors is sufficient to establish economic values.

If GCD, the CRSP electrical system and its use in a contractor's resource stack doesn't affect market prices, it therefore follows that the electrical production at the GCD is "small" in the economic sense and WECC market price are exogenously determined[4].

The resultant estimates would be the appropriate economic values provided that a change in the operation of that resulted in a loss of the electrical power resource at GCD would give rise to the need for additional resource to come into being to replace the loss. As the panelists noted:

> *. . .the marginal cost of this extra capacity would count as a real economic cost. It would not necessarily be the cost of additional capacity in CRSP – it would be the cost of additional capacity anywhere in the WECC system to which WAPA and/or WAPA contractors have access.*

- Dealing with Institutional Constraints**:**

A second aspect of establishing economic values is to determine whether institutional constraints distort economic values. More specifically, if market prices are to be used as a representation of economic cost, are there institutional constraints that cause market prices to significantly differ from economic costs? If this is the case, do these "distortions" cause a difference that is so great as to cause differences in the magnitude of economic impact of ordering of the impact of various alternative GCD operational regimes? If so, what modifications to the GT Max model, to the input data or to the analysis of model output should occur?

For clarity, institutional constraints differ from limitations on infrastructure. The legal mandate that requires that Western market the GCD electrical output to the "preference" customers rather than to "the market" is independent of whether unencumbered transmission systems exist such that Western could sell electricity to buyers in Northern California.

There are two reasons why institutional constraints may not fatally encumber the economic evaluation that would be needed the GCD AMP for appropriate decision making. In the EIS prepared by the DOI and Reclamation on the operation of the GCD in 1995[5], two estimates are made on the economic impact to electrical power for each alternative. One approach (CROD) assumes the continuation of existing federal contracts for electricity. The other approach (Hydro) assumes that GCD power is allowed to be sold to the WECC market and is dispatch for "peak shaving". In essence, the Hydro approach disregards existing legal requirements for the sale of electrical power. The results showed that, while the magnitude of the economic impact differed (the Hydro approach showed a lesser impact), the differences between the

[4] "Everything affects everything else". So, a determination that a change in the operation at GCD doesn't affect market prices in the WECC would have to be a determination made based on statistical significance. There is also the possibility that WECC market prices could be statistically significantly different, given a change in GCD operations, but not consequential and/or that the added precision is not worth the added expense. I will have more to say on this in due course.

[5] Operation of Glen Canyon Dam, Final Environmental Impact Statement, U.S. Bureau of Reclamation and Department of Interior, November, 1995

CROD approach and the Hydro approach were proportional and maintained the relative ranking of the alternatives in terms of impact.

If this example is illustrative of the effect of institutional constraints on economic impact analysis, it may be that market prices, even in light of institutional and legal constrains, within the context of GCD AMP decision making, may serve to estimate the economic value of proposed changes to GCD operation.

Another important consideration regarding institutional and legal constraints is this; the GCD AMP stake holders are often interested in the distribution of economic impacts. For example, the SEAHG report (cited above) describes an information need related to the economic impact of modified GCD operations on Native American Tribes.

For distributional impacts to be considered, it is important to identify and have a proper specification of institutional constraints and of the legal framework in which federal power from the GCD is marketed. For example, federal power from the GCD power plant is required, under the law, to be sold as firm electrical power and energy, preferentially, to certain utilities, state and federal facilities, irrigation districts and Native American tribes.

The GT Max model in consort with capacity expansion and other models

If a change in operation at the GCD gives rise to a consequential change in electrical exchange and/or prices within the WECC area, that would indicate that the relevant market for GCD electrical power is at least the "western grid". A different modeling process would be needed to estimate economic values, one that includes the electrical resources in the WECC region. This, more robust modeling would be necessary to estimate economic values.

Figure 1 below, is an illustration of a modeling process for a more robust and geographically more complete modeling process [6]. This is a flow chart that illustrates a modeling process undertaken by Western for an environmental impact statement on one of its marketing programs[7]. This process includes the several models: one that determines hydrological conditions and GCD release volumes on a monthly basis (Hydro Forecast/Condition)[8], a production model (Hydro Dam Operational Restrictions), a capacity expansion model (Utility Supply-Side Expansion) and a dispatch model (Utility Dispatch). This flow chart illustrates how several models – including a models that deal with capacity expansion and production cost, have worked together to achieve an appropriate estimate of economic values.

When the GT Max model – a production cost model – is included in a modeling effort that includes a capacity expansion model, the lack of a capacity expansion algorithm described in the panel report (page 19) becomes a mute point. The panel report states:

> *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.*

[6] *Salt Lake City Area Integrated Projects Electric Power Marketing Environmental Impact Statement*, Volume 3: Appendix A, U.S. Department of Energy, Western Area Power Administration, February, 1994

[7] The EIS was prepared by Argonne National Laboratory for Western. It was the Post 1989 Marketing and Allocation Program.

[8] This model (and others in this flow chart) were replace with the GT Max model. Therefore, in describing this flow chart, I use the term production cost model.

This statement indicates a lack of understanding. The GT Max model is production cost model which can be, and is often, configured for uses beyond estimating short-term financial costs in a closed electrical system. It can be sufficiently detailed so that it can estimate power production on an hourly basis, dynamically, from a set of three conjoined dams in Colorado (the Aspinall Units) and, when combined with other models can serve to estimate long-run marginal cost within a geographically large and complex set of electrical systems[9].
A production cost model (as shown in this flow chart) is also useful for another reason. In addition to economic values, this model, in addition to other considerations, such as Western contracts and commitment levels, allows for estimates of how economic impacts are distributed to various contractors. The distribution of economic effects is often of interest to stakeholders and decision makers and would be less precisely determined if a capacity expansion model or WECC-wide model worked alone.

Estimates of economic values related to the change in operation at the GCD was prepared for the Bureau of Reclamation (Reclamation) for the EIS on the operation of GCD published in 1995[10]. At the time the analysis was done for this EIS, electrical capacity in the WECC region was in surplus. In addition, the EIS required a 20-year evaluation of the affected resources. The consulting firm of Stone and Webster, in consultation with the cooperating agencies, prepared economic impact analysis for the EIS alternatives – all of which were changes in the operation of GCD.

[9] In the SLCA/IP Post 89 Marketing EIS, a forerunner of the GT Max model was used within a set of interactive models to analyze 15 electrical systems in the Rocky Mountain West along with the CRSP power system.
[10] Operation of Glen Canyon Dam, Final Environmental Impact Statement, U.S. Department of the Interior, Bureau of Reclamation, March, 1995.

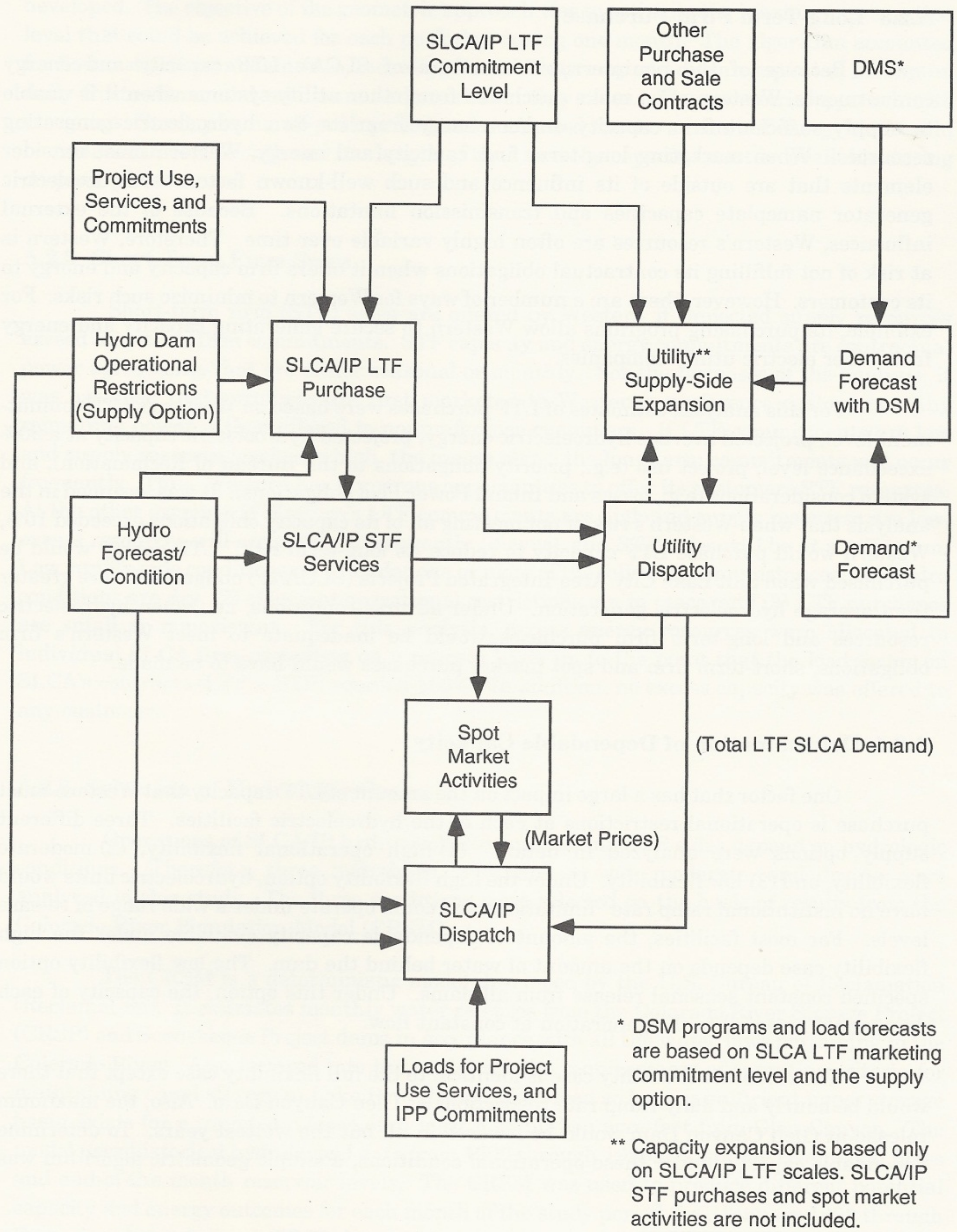

FIGURE A.7 Overview of Power Systems Modeling Methodology for SLCA/IP Power Marketing EIS

Comments by Sam Loftin
on the
FINAL REPORT OF THE GTMAX MODEL REVIEW PANEL:
Report of a Workshop held August 31 and September 1, 2011 in Flagstaff, Arizona

My comments are based on my use of the GT-Max and predecessor models for the last decade or so, and on my 33 years of experience as an electrical engineer at Western Area Power Administration's CRSP office.

Executive Summary, Pages 1-3

The purpose of the Report by the reviewers was to assess Western's and Argonne's current GT-Max model usage, usage in the LTEMP EIS, and in large geographic and time-scale power system studies. In this section, the reviewers summarize some limitations of the current model in its present configuration – some of which I agree with. Addressing some if not most of these limitations to the current GT-Max model is the purpose of the current Argonne-led DOE lab effort to create a new hydro modeling system.

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, <u>like all such models, it is an imperfect representation of reality and has limitations in how it can be applied</u>.

I agree with the above statement from the Report, and especially the underlined portion (my emphasis). We need to keep in mind that computer models are meant to help us inform decisions, but are limited in applicability, scope, and accuracy. The statement applies not only to GT-Max but to all computer models, including river system models like Riverware, sediment models, beach building models, and climate change models.

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.

I think that this statement is accurate. In the body of the report the reviewers discuss how GT-Max was designed primarily to inform short-term hydroelectric operational needs, and only secondarily for longer-term financial and economic studies. Western and Argonne designed GT-Max to do some things very well, and that is what GT-Max does best. That doesn't mean that GT-Max can't be used for other modeling problems, only that it may be more complex or time consuming to use it for longer time duration or larger geographical area studies. Or that GT-Max might need model input from other model outputs.

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.*

The reviewers discussion of Riverware here and in the body of the Report leads me to think that they don't really understand how Western uses Riverware output in GT-Max studies. Riverware output (more specifically the multi-trace [ISM] version of CRSS) is used in some GT-Max studies Western has performed or participated in, particularly the longer-term studies like the Shortage Criteria EIS, the Colorado River Basin Water Supply and Demand Study, or in projecting purchase power expenses for Western's SLIP Power Repayment Studies. Western uses Reclamation's 24-month study output more often than Riverware, particularly in the monthly prechedule studies that I do. There is no requirement to use any Reclamation model output in GT-Max – we could easily use other sources of water release data as long as those data are in a format that GT-Max can use (for instance, monthly reservoir releases in acre feet and reservoir elevation in feet).

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.

Again, true, but that wasn't what the GT-Max model was designed to do. GT-Max is unrivalled in my experience in modeling the complex operational and environmental constraints that we encounter at CRSP power plants. That is where its true usefulness lies, and that is where other power system models that I have encountered are lacking.

Three Business Models, pages 7-9

The reviewers present an overview of the business models found in North American power markets; ISOs like the California ISO, traditional bilateral markets, and a mixture of the two like is found in the Western Interconnection. They then discuss Western business model.

With available excess capacity, Western could bid into California markets when either energy or ancillary services prices make it financially attractive.

Reading these sections suggests that the reviewers prefer the ISO model and would like Western to move its business model in that direction. They advocate for models that can better characterize sub-hourly hydroelectric operations for ancillary services. This advocacy continues in other sections of the report and in the Conclusions and Recommendations. This business model doesn't really fit with the current model that Western operates under. Our statutory requirements and limitations make Western significantly different from a typical Investor-Owned or Publicly-Owned Utility and limits our ability to do as the reviewers propose.

Typical Application and Unique Features, Page 12

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.*

The reviewers compare GT-Max with other commercially available production cost models. They correctly emphasize the superiority of GT-Max for modeling complex hydro operations. This is a topic that the WECC Hydro Modeling Task Force (HMTF), that I participate in, spends a great deal of its time on. WECC is using commercial products such as Promod and Gridview to simulate WECC-wide operations while simulating widely varying hydro plants, each with its own set of constraints. The hydro operations of individual members' systems are much more complex than can be characterized in such models, so the HMTF continues to experiment with, develop, and implement methods to better characterize hydro operations.

Objective function, solution algorithms, fundamental period, pages 12-15

In any case, all objectives have to be reduced to a single number for a computer model or analyst to compare and rank alternative plans.

In my modeling work at Western, I never look at the "single number". The useful output from the model is the modeled hourly operations in megawatts at each power plant, total generation over the month, and the overall purchase/sales dollar information.

Key Exogenous Data and Constraints, pages 17, 18

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.

See my comments on Riverware in the **Executive Summary** section.

The reviewers appear to have the relationship between Riverware and water release decisions reversed. Reclamation, at Western's request, programs additional water into the summer and winter months because it is more valuable to Western then. Riverware then takes those release preferences and incorporates them into future release patterns. In this section, the reviewers imply that water is not more valuable for generation in the summer and winter than the spring and fall. Western's power allocations to its customers peak in the winter months (primarily December, January, and February) and summer months (primarily July and August), so that is why we ask

Reclamation to program higher water releases in those months. Additionally, prices for firming power purchases also peak in those months so we try and avoid making purchases then when possible.

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.

Reclamation has looked at potential climate change effects on Colorado River water resources in the recently completed Colorado River Basin Water Supply and Demand Study[i], done in conjunction with the seven Colorado Basin States. DOE has also recently completed its report on the effect of potential climate change on Federal Power Marketing Administrations, the Section 9505 Report [ii]. Both of these reports specifically address potential changes to Colorado River runoff and its effect on hydropower operations. Reclamation can incorporate information from those studies into Riverware, and that information can be incorporated into GT-Max modeling.

It is interesting to note in particular that the Section 9505 Report looked at projections of climate change in the next several decades. The projections were prepared by Oak Ridge Laboratory on behalf of the Department of Energy and showed that the potential changes in runoff are well within the historical climate variability that Western has experienced over the last 20 to 30 years. The projections actually showed an increase in Western generation in several of the river basin regions of our service area, contradicting the drying trend in the western states that is generally assumed to be the result of global warming, and is predicted in the Colorado River Basin Water Supply and Demand Study. This result led Western to conclude in the report that our existing authorities and operations and marketing programs were adequate to accommodate any potential changes due to climate.

Capacity Expansion Algorithm, pages 19, 20

This section notes the lack of capacity expansion planning in GT-Max. Since Western has no legal authority to add capacity or serve load growth, it is understandable why GT-Max would not include this feature. It might be easier to just access capacity expansion data and model output and import it into GT-Max when a longer term study is required, rather than adding the bulk and complexity to the existing model.

Reserves commitment and ancillary services algorithms, pages 20 and 21

See my comments to the Three Business Models Section. The reviewers again advocate for using Western's hydro system for providing ancillary services to renewable, non-dispatchable generation. This advocacy seems misplaced in a review of the GT-Max model. Perhaps the reviewers saw this report as their only opportunity to influence Western's policy direction.

Unit reliability algorithm, page 21

The reviewers are correct to note that GT-Max treatment of unit outages is less that optimal. GT-Max simulates power plants as a lumped total, rather than at a unit level, and any plant deratings are in monthly increments. In my experience using GT-Max, accurately modeling unit outages is one of the more challenging and time consuming aspects of the job. It is my understanding that the new Hydro model Argonne is creating will significantly improve on this aspect, being able to model individual units on time scales of less than a month.

Long-term risk algorithm, pages 21 and 22

I disagree with the reviewers thoughts that GT-Max should include long-term risk algorithms. I think that computer models that become too large and complex become unwieldy to use and more prone to giving inaccurate results. If you want a good laugh, go back and read some of the reports that were produced 20 years ago using those expansion models and see what they were projecting. I agree that long-term risk is a worthy subject to study, but think that it should be done separately from GT-Max.

Energy Market Prices, pages 22 and 23

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.

I suspect that generation changes at Glen Canyon and CRSP in general could, in the most extreme circumstances (High Flow Experiments or very low flow drought scenarios), affect local power prices by flooding the market with surplus generation, or by buying most available generation surpluses. I don't have any evidence, however, it is just a hunch.

I agree with reviewers that the ability to incorporate a probability distribution of power prices rather than a single price would be an improvement to GT-Max. That would require multiple runs of the model to look at the entire range of prices, which would add considerably to the complexity and model run time.

Ancillary Services, pages 25 and 26

The reviewers again advocate that Western enter the ancillary services market in the Western Interconnection. See my comments above in the **Reserves commitment and ancillary services algorithms** section and the **Three Business Models** section.

Capacity value—lack of conceptual clarity, pages 26 and 27

I agree with the reviewers that Western's treatment of capacity and its value is inconsistent. Most of the monthly GT-Max operational modeling that I perform doesn't take capacity value into account at all, since we firm our hydro capacity almost completely with firm energy purchases rather than capacity purchases. In other studies Western has done, capacity value is included, but the values vary based on what information we have available at the time. I think the lack of good sources of knowledge of what capacity sells for in the Western Interconnection is a big impediment – more so than any deficiency in GT-Max.

Riverware, page 28

See my comments on Riverware in the **Executive Summary** section.

Large-Scale and Long-Term Risk, page 28

See my comments in the **Key Exogenous Data and Constraints** section above. The reviewers misunderstand that Western, as a wholesale supplier of a defined resource base, has no responsibility for load growth or changes in retail loads. Western can't just decide to change its business model without change to the legislation that governs our operations.

Conclusions and Recommendations, pages 30 through 32

I think all these subjects have been covered in my comments above.

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[i] http://www.usbr.gov/lc/region/programs/crbstudy/finalreport/index.html

[ii] Department of Energy (DOE) Report to Congress on Climate Change and Federal Hydropower (Section 9505 Report) http://nhaap.ornl.gov/content/climate-change-impacts

Comments by Tom Veselka and Les Poch
on the
FINAL REPORT OF THE GTMAX MODEL REVIEW PANEL:
Report of a Workshop held August 31 and September 1, 2011 in Flagstaff, Arizona
Draft of Tuesday, September 04, 2012

Argonne National Laboratory (Argonne) staff would like to thank the Grand Canyon Monitoring and Research Center (GCRMC) for hosting the "*GTMax Model Review and Knowledge Assessment for Hydropower*" workshop conducted in Flagstaff, Arizona on August 31 and September 1, 2011. Participants included staff from GCRMC, the Western Area Power Administration (Western), Argonne, members of the review panel, and other interested individuals.

The comments below are made by Les Poch and Tom Veselka from Argonne who presented GTMax materials at the workshop. Comments are mainly in response to information contained in the document entitled "*Final Report of the GTMax Model Review Panel*" that Western management received for comment on October 10, 2012. Note the review document was distributed to presenters more than 13 months after the conclusion of the workshop. Therefore, instead of relying on our recollection of what transpired during the workshop, the comments below are primarily based on the review document and PowerPoint presentations given at the workshop.

Reviewer comments and suggestions address GTMax general modeling frameworks and methodologies as well as more specific aspects of hydropower modeling. Below we remark on several facets of reviewer comments, add background information about modeling, and provide justification for the GTMax structure, scope, and methodology.

Production Cost Modeling and Mixed Integer Linear Problem Formulation

In the 1st paragraph of the executive summary the review document states "*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 power facilities at least cost. As is typical of such models, it simplifies what is in reality a very complex system of interrelated 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.*"

In general, we agree with the above reviewer comments as individual isolated statements. As modelers with a combined working experience of almost 70 years in power system modeling and analysis, we recognize that no model is perfect. Furthermore, we acknowledge that proper model application and interpretation of results are of utmost importance. However, we would like to clarify that GTMax is more accurately classified as a production cost *optimization* model as opposed to a *simulation* model. Also the objective of GTMax as it is applied to the CRSP system is to maximize the economic value of federal power resources using market price signals, not to minimize hydropower production costs as stated by the review panel. In the main body of the final report, reviewers state that "*If purchases are less expensive than dispatching a Western unit, the model will displace the unit.*" This is an inaccurate portrayal of GTMax and the dispatch of hydropower resources in general. CRSP marginal production costs are miniscule – there are no fuel costs and variable operating and maintenance (O&M) costs are for all practical purposes either zero or very small. Therefore, CRSP hydropower production costs are almost always less than market prices. Instead of using a production cost minimization objective, GTMax schedules limited water resources to maximize hydropower water resources.

Readers of the external review document should also be aware that, although not perfect, production costs models are extremely useful. Readers should also realize that the optimization techniques that GTMax utilizes have been extensively used by other models in the past and continue to be widely applied by utility companies and academia throughout the world.

The GTMax model is comprised of a large set of equations that are formulated as a network problem which describe the operation of one or more interdependent systems. In addition, it includes equations that represent physical processes, institutional limitations, and time sensitive scheduling problems. Although the GTMax model possesses several aspects of a network flow optimization problem, there are some fundamental differences from a pure network problem. Unlike traditional network flow models, GTMax contains more complex features. Properties of a resource may be altered as it flows through a network and/or over time and there are numerous temporal constraints, which are more common in sequencing and scheduling problems.

Core mathematical relationships in GTMax require that equations are linear functions. In addition some variables are declared as “integers”; that is, solutions for these variables are required to be discontinuous integer number values. Solutions for other variables, referred to as “real variables” in the mathematical problem, are allowed to be continuous real number values. These two requirements place GTMax core functions into a classification that is commonly referred to as a “mixed-integer linear program (MILP)” problem. The solver that GTMax uses has been shown to solve real-life problems such as the ones required to accurately optimize Colorado River Storage Project (CRSP) operations with tens of thousands of variables and constraints.

Water and hydropower systems are inherently nonlinear and discontinuous, seriously challenging the limitations of leading optimization software packages and the computational capabilities of our most advanced computer systems. While a Mixed Integer Non-Linear Program (MINLP) can most accurately represent the problems modeled by GTMax, the current state of MINLP technology limits its use to tiny models only. GTMax problems typically require thousands of variables and constraints. Considering the complex structure of GTMax and the large problem sizes it solves, we use a general-purpose MILP solver to find the solution.

Linear Programming (LP) techniques in electricity systems modeling have been widely used by academics and electric utility companies since the 1950’s. One study stated that the MILP approach shows the greatest potential for addressing the unit commitment problem for power systems that have combined-cycle generating units (Kinetrics, Inc. 2005). LP and MILP problem formulations have been used to determine Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) for the largest power grids in the world. Some electricity market simulation models using LP and/or MILP include AURORAxmp, PLEXOS, GridView, PROMOD, GE MAPS, and GenTrader.

AURORAxmp was developed by EPIS, Inc., in 1997 to model competitive wholesale electricity markets. It has been licensed to over 60 users such as electric utilities, independent power producers (IPPs), government agencies and regulators, electricity traders, hedge funds, and energy industry consultants in North America, Europe and Asia.

PLEXOS was developed by Energy Exemplar to model electricity markets. By the beginning of 2012 PLEXOS was installed at over 135 sites worldwide. It is currently being used by National Renewable Energy Laboratory (NREL) to study the impact of a proposed energy imbalance market (EIM) in the Western Interconnect (WI).

GridView was developed by ABB and is a security-constrained unit commitment and economic dispatch model. It has been used by the California Independent System Operator (ISO), Southwest Power Pool, the New York ISO, NREL, and others. It was used to perform a cost/benefit analysis of a proposed EIM for WECC in 2011.

PROMOD was developed by Venytx and has been used by energy companies for 30 years. It is currently being used by WECC to perform integrated energy and capacity analyses.

The Multi-Area Production Simulation Software (MAPS) is a chronological simulation model developed by GE. It has been used by numerous transmission companies, PJM, the New York ISO, the New England ISO, and the Midwest ISO to perform reliability studies, and transmission and generator expansion studies.

GenTrader was developed by PCI in 1999. It has been used by utilities such as South Carolina Electric & Gas, Mirant, Kansas City Power and Light, and utilities in the deregulated Texas market such as Reliant Energy, TXU, and Calpine Corp.

Last, but not least, GTMax and its predecessor, the Hydro LP model, have been used for approximately 20 years. When it was first developed no production cost model was available to adequately address hydropower issues at a level of granularity that Western needed to conduct analyses in support of a Power Marketing Environmental Impact Statement (EIS). Western funded Argonne to create a model that mimics its core business function – the dispatch of the Colorado River Storage Project (CRSP). The basic design however is very flexible and can also be used to optimize operations of other systems. Consequently GTMax projects have been sponsored by the Bureau of Reclamation (Reclamation), International Atomic Energy Agency (IAEA), USAID, World Bank, Fichtner GmbH & Co KG (Germany), Adica Consulting, ENRON, and Chubu Electric Power Company (Japan). These studies have been applied to hydropower-centric problems in the United States, Asia, Africa, and several regions in Europe.

The review panel concluded that among production cost models GTMax is exceptional in its representation of hydroelectric systems. We are pleased that reviewers gave GTMax high marks for the purpose it was designed; that is, optimizing the economic value of hydropower plants under a large range of operating criteria and constraints. Determining economic value is a core task that is performed under EISs that examine operational changes in electric power systems.

GTMax has a hydropower-centric design and is tailored to perform specific tasks. It focuses on what is important for problems that are of interest to Western and CRSP stakeholders. This design helps it overcome some of the shortcomings of dispatch models that are designed for more general and broader applications such as imperfect modeling of "*inter-related electricity faculties*" and "*decision factors*" that review committees members listed in the 1st paragraph of the executive summary.

Not only does GTMax better dispatch hydropower plants than the vast majority of production cost models, it also better reflects actual "*decision factors*" regarding water operating criteria as it respects dispatch guidelines and goals that are specific to the CRSP system. It also addresses "*inter-related* *electricity facilities.*" The GTMax CRSP topology links CRSP power facilities together as an interconnected system and explicitly simulates the connectivity of water resources, the flow of water throughout the systems, and water related impacts on power resources. In addition to water resources, GTMax simultaneously schedules Western's federal hydropower resources and engages in short-term firm bilateral power market transactions and spot market activities to meet its obligations to serve firm loads.

The review panel recognized that GTMax is able to account for and simulate the effects of these relationships among CRSP facilities. However, reviewers stated "*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*." Reviewers failed to mention that Western and Argonne staff devised an elegant and effective methodology for isolating and assigning these effects to Glen Canyon Dam. The technique was described in the workshop presentation titled, *Methods for Representing CRSP Resources*.

Reducing Operating Objectives and Constraints to a Single Number

GTMax determines values for "decision variables" that maximize a given function, called the "objective-function," while satisfying given inequalities of other functions called "constraint-functions." The executive summary of the review panel document discusses the "*single number*" that the model produces. This number is essentially the GTMax objective function value. For CRSP applications, the objective function maximizes the economic value of CRSP energy resources over a user-specified time period. This "bottom-line" economic value is comprised of a multitude of additive components. Readers not knowledgeable in LP and MILP modeling should realize that the objective function in large problems such as those posed by the CRSP system is dependent on numerous variables.

The GTMax model determines values of decision variables for all chronological hourly time steps during the model timeline. This timeline typically spans a one-week period. This time chronology feature of GTMax allows it to simulate a host of operational aspects, such as generator ramp-rate limitations, unit commitment schedules, thermal unit starts and stops, and multi-time-period constraints, including maximum and minimum water releases from a reservoir over the simulated period. When optimizing, the model recognizes that the solved state of the system at any point in time affects operations at all other points during the optimized time period. Simulated time is also critical for solving network interdependency problems, such as cascaded reservoirs, because GTMax recognizes reservoir connectivity and the time it takes water to flow through a system.

Therefore, in addition to producing a value for the objective function, GTMax also solves for and produces literally thousands of other results in a typical CRSP optimization run. Some key model outputs include hourly generation levels for each hydropower plant, power and non-power reservoir water releases, reservoir storage volumes and associated forebay elevations, downstream water flow rates, river stage, and marginal values for both water and energy throughout the interconnected network. Therefore, GTMax should not be viewed as a "black-box" model that produces a single inexplicable number. Instead each component of the objective function value is transparent, explainable, and traceable through an analysis of model outputs, constraints, scalars, and equation constants and coefficients.

Workshop Purpose and Proposed Markets

One section of the review panel report describes the purpose of the workshop. We agree with the review panel's first sentence that states "*The purpose of this 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*." However, in the text that follows we find a disconnect between what we were asked to present by GCRMC organizers and several of the statements made by the review panel. The review panel report discusses "*proposed and future uses of GTMax and assess the applicability of the model to anticipated future economic and financial issues*." Reviewers then briefly describe how the power sector is evolving and different types of power sector business models. Then in the sections that follow reviewers are critical of GTMax in its present form since it may be ill-equipped to model potential changes in the Western Interconnect (WI) such as evolving market structures and future supply resource mix – in particular, an increase in variable resources.

Regarding the applicability of GTMax for future studies we would like to point out that GTMax is not a static model. Instead, it has been extensively modified and enhanced to meet the evolving needs of Western to reflect changes in reservoir operating criteria and alterations in Western's marketing goals and objectives. In our opinion it is premature for Western to expend some of its limited resources to either upgrade GTMax or develop new models to better represent potential market structures and business models that are not yet applicable to the CRSP system. Reviewers specifically refer to the proposed WI Energy Imbalance Market (EIM). At the time the workshop was conducted EIM market rules and structures were under development. Although more than16 months have passed, EIM rules have not yet been fully defined and agreed upon. Basic economic analyses continue to be conducted and it is not certain if the envisioned structure of the WI-wide EIM will materialize in the foreseeable future. Western has generously funded GTMax upgrades on an as-needed basis to meet specific needs or in support of well-defined projects. It is anticipated that future upgrades will be made as deemed necessary by Western or in support of GTMax projects funded by other organizations.

Argonne and Western staff are fully aware of changes in the WI markets and are engaged in EIM related activities via participation in webinars, workshops, internal meetings, and through extensive reviews of EIM reports and presentations. In addition, at the request of Western, Argonne has performed an extensive analysis of EIM models, methods, and results to help Western make more informed EIM decisions (Veselka et al. 2012); the report is available to the public at the Department of Energy (DOE) Information Bridge web site at http://www.osti.gov/bridge/.

In addition, several years ago Argonne developed the Electricity Market Complex Adaptive System (EMCAS) to model the behavior of participants in electricity markets under a well-defined set of market rules (DIS 2007*)*. The model has been applied to studies in both the U.S. and Europe. Through this work and our extensive study of both domestic and international markets we disagree with reviewer statements that suggest that "*the fundamental economic behavior driven by cost minimization provides a common foundation that underlies the behavior of market participants in both market and non-market segments of the industry*." In contrast we find that in a competitive marketplace, market players acting as autonomous agents, are driven by corporate objectives such as profit maximization and/or to increase market share. This is in stark contrast to traditional markets in which the cost-minimization objective is the primary force behind utility behavior. In a perfectly competitive market in which there are no barriers for new market entrance, the end result in theory may be cost minimization. However, no such market exists – especially in the utility sector in which market players under some conditions can influence market clearing prices. Later in the review document it states "*Formal electricity markets sharpen the profit incentive of all participants ….*" The statement appears to conflict with prior statements since there are stark differences between cost minimization and profit maximization objectives.

If we had been informed that the workshop would focus more on how Western may model future markets and conditions, the content and focus of workshop presentations would have been different. We would have discussed market issues and ways in which EMCAS algorithms could potentially be leveraged to better represent anticipated changes in the WI and Western's response to these changes. However, it is premature to develop a model for a voluntary EIM that is not yet fully defined and may never be implemented.

Review panelists also suggest that Western engage in marketplace activities that overstep its statutory boundaries and in some instances are physically impossible. Some of the statements include "*opportunities for western generation asset owners to increase returns on operation of their plants*", "*the potential to expand the opportunities for profitable operation*", "*bid into California markets when either energy or ancillary services prices make it financially attractive*", and engage in day-ahead and real-time market "arbitrage." Western is a U.S. government agency that schedulers federal resources; it is not a publicly-traded company that is obligated to maximize shareholder value. Instead its primary mission is to maximize the economic value of federal resources. Ultimately these federal facilities belong to the citizens of the U.S. Western must abide by the Colorado River Storage Project Act, its statutory and delivery obligations, and WAPA's prevailing contractual delivery obligations to existing customers. CRSP resources are already fully dedicated to existing contractual obligations, regardless of specific Colorado River Basin hydrological condition. This includes Western's statutory obligation to market federal project hydropower at the lowest possible rates to consumers consistent with sound business practices. In our view, Western has neither the resource flexibility nor the discretion to pursue reviewer suggestions.

Ancillary Services and Higher Penetration of Variable Resources

Regarding comments concerning the model's treatment of ancillary services we find that reviewers were not adequately informed about or did not fully grasp the model's capabilities. The reviewers state that "*GTMax de-rates hydroelectric generation capability to capture the cost to provide for these services.*" This statement is correct as it applies to the treatment of ancillary services in the CRSP system. We utilized this methodology for CRSP because it adequately captures the impacts of providing ancillary services on hydropower plants operations and system economics. However, reviewers also state that "*GTMax fails to make commitments for security reserves, even at the hourly time step*" and later in the text "*the absence of ancillary service valuation capacity is conspicuous.*" These statements are incorrect.

Not only can GTMax explicitly model ancillary services, it also contains options to represent spinning reserves on an hourly basis as spare generating capacity. Units that provide spinning reserve services must be synchronized to the grid (i.e., are in generation mode in GTMax). The regulation service is used to compensate for (or react to) very short-term (in the range of seconds) changes in the grid through the use of unit automatic generation controls (AGCs). A powerplant providing this service must also be in generation mode in GTMax.

In GTMax units that supply ancillary services affect the range and flexibility of operation to serve load and/or for energy sales. Regulation up and spinning reserves reduces maximum energy schedules. That is, the sum of those two ancillary services plus scheduled energy production at all times must be less than or equal to the maximum operational capacity of the units. For hydropower operations GTMax also ensures that hydropower plants release enough water from reservoirs to accommodate the sum of the minimum flow rate requirement plus regulation services down. The GTMax user sets ancillary service limits by unit/plant and the model then optimizes ancillary service assignments to meet total system and/or subsystem requirements. We find that other production cost models use a similar approach.

Although the current GTMax treatment of ancillary services is adequate under current conditions, the situation may change in the future. The panel review states "*With Western and the WECC entering into a period of increasing generation from renewables and therefore also possibly the need for ancillary services…."* We agree that there is a trend toward more renewables (more specifically variable resources) in the WI. However, it should be noted that Western's current ancillary service obligations are based on its participation in a reserve sharing group and it will sell additional services through bilateral agreements. Also, Western will not construct any variable resources in the foreseeable future and at this point in time there are no plans for forming ancillary services markets in the larger WI footprint. Ancillary services markets are outside the realm of the proposed WI EIM. It is prudent for Western to wait and gain more information about how the system will evolve and about future institutional arrangements before making modifications to either GTMax or adopting a new model.

Regarding ancillary services, reviewers also state *"GTMax cannot simulate operational periods of less than one hour*." We acknowledge that it cannot solve for movements at sub-hourly time intervals such as instantaneous variations in load, continuous changes in generation as a unit ramps between set points, and second-by-second fluctuations in production as units respond to AGC signals. Improvements can be made in this area. To increase and more effectively utilize hydropower in the U.S. the Department of Energy (through Western) entered into a memorandum of understanding with the Department of Interior (through Reclamation) and the Department of the Army (through the Army Corp of Engineers). This partnership is assisting a team of specialists from 4 DOE laboratories to demonstrate a newly developed Water Use Optimization Toolset (WUOT) at the CRSP system. One component of these toolset models is a very detailed, high fidelity hydropower day-ahead scheduling and real-time dispatch tool that operates at user-specified time steps. At present it is designed to model operations at time steps as short as 5 minutes. Another tool deals with inflow water forecasts, longer-term reservoir water routing, and the environment.

The WUOT is also being demonstrated at the Oroville-Thermalito Complex which is in the California ISO and at the Conowingo/Muddy Run pumped storage facility located in the PJM footprint. Western's participation in the WUOT project requires minimal expense and will help prepare for its next generation modeling needs. Application of the day-ahead scheduling and real-time dispatch tool to the CRSP system is ongoing. Preliminary results have been documented and sent to DOE for review.

<u>Modeling Scope and Fidelity</u>

Reviewers suggested that the scope of GTMax be expanded in time and space with a more refined level of granularity and fidelity. To some degree we appreciate this broader perspective and the notion that in principle, everything in this universe and beyond is connected. Sir Arthur Eddington wrote, "*You cannot disturb the tiniest petal of a flower without the troubling of a distant star*." Unfortunately given our present state of technology and knowledge, there are practical limits to achieving this goal. No single model can do everything and answer every question perfectly with a high degree of fidelity. Therefore, a crucial part of any modeling task is to determine what is important and what is not to answer a specific question within the scope and budget allocated to a project. We chose to concentrate on the central problem when applying GTMax. This strategy has been very successful and useful. For example, schedulers in the CRSP Energy Management and Marketing Office located in Montrose, Colorado review GTMax model results each month and use model outputs to aid in their decision making. This is a strong testimony that the model accurately represents of the dispatch of the CRSP system and provides both realistic and meaningful results.

Our approach has been and continues to be to improve the water management and power dispatch functions in GTMax, rather than to expand its scope. As a model grows in scope, the problem size often becomes overwhelming and forces modelers to make compromises in terms of spatial and temporal fidelity. This tactic could potentially compromise the current integrity of the model in terms of its ability to produce realistic CRSP dispatch results. Furthermore, Western has no legal authority to build new capacity, such as wind and solar, or to serve load growth.

To investigate some of the broader issues we leverage a set of specialized tools to feed pertinent information into GTMax. Some of the toolset models (and/or model outputs) that we have used in conjunction with GTMax in the past include: (1) WASP - capacity expansion results provide GTMax with new thermal and hydropower plant additions; (2) Aurora model - results supply GTMax with estimates of future locational marginal prices (LMPs); (3) Riverware - provides GTMax with estimates of future monthly water releases and reservoir storage levels; and, (4) VALORAGUA - provides GTMax with hydrological information in a multi-country region. This approach allows GTMax to focus solely on weekly CRSP operations based on a set of operating limits, goals, and guidelines to evaluate operations in terms of (1) the economics/financial value of energy; and, (2) plant-level "operating" capacity while leveraging results and insights produced by other models to help guide the hourly dispatch from a longer term and broader perspective.

In our opinion, using the toolset approach is a practical and reasonable methodology for conducting studies within the confines of project resources. However, the review panel report states "*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.*" We disagree with the reviewers on this point. Without challenge from numerous affected parties over the last 20 years, GTMax and GTMax-light have been used for this exact purpose. This encompasses numerous studies in support of EISs, and both economic and financial analyzes of CRSP facilities. GTMax performs an economic dispatch under a very specific set of conditions. This set of conditions may be for today, next week, a year from now, or 50 years into the future. Basic dispatch principles are not expected to change; however, model inputs as guided by specialized long-term tools will vary during the course of a long study time horizon. For example, for long-range studies, GTMax relies on results from the Riverware model for future estimates of reservoir water releases and reservoir storage volumes. This allows GTMax to alter its dispatch in response to anticipated changes in hydrological conditions over time. To the extent that the Riverware run has incorporated the effects of global warming into its projections, these will also be reflected in GTMax model results. In this context, GTMax is one piece a model toolset; it is not the sole analytical tool.

Reviewers are concerned about the applicability of GTMax for long-term studies because it does not expand system capacity. The review document states "*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 ….*" We agree that new capacity will be required in the future to maintain reasonable prices. However, embedding MILP equations in a production cost model to expand capacity is not the only approach or always the best method of estimating future WI prices. Reviewers point to research that *"argues that the perfect information assumption of production simulation models and other simplifications make them a poor predictor of electricity market prices*." For CRSP applications, we typically project prices based on futures market indices. As required we can extend forecasts using Energy Information Administration electricity prices projected by the National Energy Modeling System (NEMS) through 2040. This model has a very broad national perspective that goes beyond the WI and the electric sector. We have also used projections made by other models such as Aurora.

We acknowledge that using a fixed price vector has a conceptual weakness since market prices do not react to actions taken at Glen Canyon Dam. One approach that we used to model hydropower systems in the Iberian Peninsula is to use a market price curve instead of a static value because alternative actions often resulted in significant changes in system marginal production costs. However, changes in Glen Canyon Dam operating criteria affects only 200 MW to 400 MW of capacity; that is only 0.1 % to 0.2% of the total WI capacity. Therefore, in past model applications we assumed that capacity swings of this magnitude would have only miniscule impacts on market clearing prices. We based this assumption not only on the small change in generation swings, but the fact that the WI marginal fuel is predominately natural gas. Nevertheless, Argonne is conducting a simplified WI analysis to further study the validity of this assumption.

It should be noted that GTMax has the capability to compute LMPs instead of using exogenous market prices. This modeling option has been exercised in GTMax applications in Europe, Asia and Africa. For long-term applications, we always incorporated exogenous capacity expansion schedules into GTMax topologies. Also, in each of these studies there were adequate data available and sufficient support from utility system experts to perform realistic price calculations.

From comments in the review panel report, it appeared reviewers did not fully understand and appreciate the approximation methods that were used for evaluating capacity costs when time and money do not allow for a more thorough analysis. One of these approximation methods was used for two Reclamation EISs and approved by Reclamation, Western, and Western customer representatives. During the Power Marketing EIS, which was led by Western, and the Glen Canyon Dam EIS, which was led by Reclamation, a more rigorous approach was implemented. Modelers and analysts prefer a more detailed approach, but it is also very expensive and time consuming. In these studies capacity expansion models were run for each of Western's largest customers for each EIS alternative. Experts from each of the utilities modeled provided advice and supplied detailed information about systems operations, objectives, and the slate of candidate expansion technologies.

It is our impression that reviewers would like to employ an even larger and broader perspective by estimating the capacity expansion impacts on the Western Interconnect (WI). Such a model may generate numbers, but it is important to recognize when model "answers" are meaningful. We contend that capacity expansion for the entire WI is based on judgments made by a multitude of independent decision makers. Each has unique objectives, operating conditions, and financial status. Coupled with federal and state laws, renewable portfolio standards (RPS), wind and solar integrations, uncertainty, unique system-level hydropower/water conditions and regulations, national policies etc. makes modeling realistic capacity expansions on a WI level extremely difficult.

Connection issues in the WI are extremely complex and interwoven which makes some of the broader issues beyond the mission and capacity of Western. For example, reviewers suggested that GTMax should quantity the grid benefits of ancillary services. This one task by itself is an enormous problem. Over the last several years, DOE and other organizations such as EPRI have sunk many millions of dollars investigating the grid value of hydropower. Argonne staff members have participated in several hydropower grid services meetings and have reviewed project documents. More recently DOE has funded Argonne to lead a team comprised of national laboratory experts, prominent hydropower consultants, software developers, and utility experts to perform further modeling and analysis on this topic. This project is in addition to the WUOT mentioned earlier. Similar massive studies, years in the making, investigate WI wind and solar integration, energy markets, the system-wide level representation of hydropower, global warming effects, etc. These investigations are ongoing and will continue into the foreseeable future. To the extent possible, it may be possible to leverage information and/or products generated by these projects.

These WI power issues and very long-term trends such as climate change are of great interest, but in our opinion the marginal value of incorporating these factors into CRSP studies for evaluating the power economics of Glen Canyon Dam under alternative operating criteria are very small, exorbitantly expensive, and the confidence level of the model results would be low. We base this option on the following rationale.

(1) Alternative operating criteria imposed at Glen Canyon Dam has very little or no impact on the annual amount of power it produces. In an average hydrological year this accounts for less than 0.6% of WI generation and will progressively decrease in percentage terms over time.
(2) Alternative operating criteria typically increases or decreases Glen Canyon Dam operating capacity by only 200 to 400 MW. This represents only 0.1% to 0.2% of WI generating capacity and it will progressively decrease in percentage terms over time.
(3) The marginal fuel in WI interconnect is predominately natural gas which is abundant and projected to continue to be inexpensive. Therefore, in theory any change in production cost as a result of Glen Canyon operations is primarily a function of changes in heat rate making the cost curve relatively flat. This is the primary reason that pumped storage power plants are rarely used for arbitrage in current WI markets.
(4) Since economic analyses focus on differences among alternatives and not absolute values, the effects of long-term large scale issues such as climate change on the decision-making processes are significantly diminished compared to changes in absolute values.
(5) WI operations are influenced by a multitude of autonomous decision makers in a massive system that is not only exceptionally diverse and complex, but interwoven with water, economic, and political/legal considerations that transcend even the most sophisticated models. Although models may produce "numbers" based on economic theory, this result is very difficult to defend given the simplifying assumptions that are required and the quality and granularity of model input data. Especially when operational changes at Glen Canyon Dam comprise a small fraction of the total grid resource.

Therefore, it is our opinion that it would be a mistake for GTMax to shift focus away from the "flower petal" and on to the "distant star." At the CRSP level, Western has adequate information and data along with the expertise to produce high quality results. In addition, CRSP relationships are well defined and understandable with a high degree of fidelity. To the extent that changes in long-term large scale grid operations can be measured with an acceptable level of accuracy we rely on other models to provide GTMax with direction.

Concluding Remarks

In the introduction the review states that the objectives of the report are "*to review the GT Max model and its uses for economic analysis of issues relevant to the Glen Canyon Dam Adaptive Management Program.*" It appears the focus of the report significantly strayed from this objective throughout much of the text. Instead, it discusses market issues that are not yet applicable to Western and futures that may or may not come into fruition. We are pleased that reviewers found GTMax exceptional in its ability to perform hydroelectric analyses. Unfortunately, most of the review discussed issues that are beyond the current design and scope of the model; that is, it mainly discussed what GTMax does not do. It focused on the inability of GTMax to adequately represent ***potential*** WI-wide changes that, from their viewpoint, ***may be important in the future***. It also suggests the model include actions that are outside the boundaries of Western's statutory obligations.

The reader of the review should recognize that GTMax is not a stagnant model, but it evolves to reflect changing conditions. As instructed by workshop organizers, our presentations were geared toward describing the model and past applications. If informed prior to the workshop that the focus was on issues such as global warming, different utility business models, capacity expansion, and ancillary services, we would have structured our presentations accordingly to describe how GTMax can be integrated with other tools to address these issues.

While we have an appreciation for longer-term and broader perspectives discussed by the reviewers, it should be recognized that no model can do everything. Therefore given limited resources we have developed GTMax to addresses critical operational issues as it pertains to the CRSP system. The narrower scope of GTMax should be viewed as a strength, not as a weakness. It allows GTMax to produce realistic results that are both useful and used with acceptable run times. A testimony to the validity is that it is used on a monthly basis by the CRSP Energy Management and Marketing Office to make CRSP-related decisions. By broadening the scope of GTMax this strength may become diluted. Although there are some very important and interesting topics raised by the reviewers, it is our opinion that some modeling suggestions are extremely costly to implement and of small marginal benefit in terms of addressing pertinent questions related to the economic costs of altering Glen Canyon Dam operations.

As with any model, it is important to make decisions regarding what issues are of importance to the problem it addresses. Reviewers however, discuss broad WI issues that span multiple decades, yet advocate a modeling time step of 5 minutes or less over a vast and complex system. It is our opinion that these issues are beyond the direct scope of issues related to the Glen Canyon Dam Adaptive Management Program and best addressed in other forums.

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CREDA
Colorado River Energy Distributors Association

ARIZONA
Arizona Municipal Power Users Association

Arizona Power Authority

Arizona Power Pooling Association

Irrigation and Electrical Districts Association

Navajo Tribal Utility Authority (also New Mexico, Utah)

Salt River Project

COLORADO
Colorado Springs Utilities

Intermountain Rural Electric Association

Platte River Power Authority

Tri-State Generation & Transmission Association, Inc. (also Nebraska, Wyoming, New Mexico)

Yampa Valley Electric Association, Inc.

NEVADA
Colorado River Commission of Nevada

Silver State Energy Association

NEW MEXICO
Farmington Electric Utility System

Los Alamos County

City of Truth or Consequences

UTAH
City of Provo

City of St. George

South Utah Valley Electric Service District

Utah Associated Municipal Power Systems

Utah Municipal Power Agency

WYOMING
Wyoming Municipal Power Agency

Leslie James
Executive Director
CREDA
10429 S. 51st St., Suite 230
Phoenix, Arizona 85044

Phone: 480-477-8646
Fax: 480-477-8647
Cellular: 602-469-4046
Email: creda@qwest.net
Website: www.creda.org

January 7, 2013 VIA EMAIL

David Lytle - USGS
Jack Schmidt - GCMRC

RE: Final Report of the GT Max Model Review Panel (September 2012)

Dear David and Jack:

CREDA members appreciated the opportunity to participate in the August 31-September 1, 2011 workshop held at GCRMC's offices, and during day two of the workshop, presented information reflecting work undertaken by a CREDA planning, operational and analysis committee over the past couple of years. As a member of the committee, Dave Slick presented a utility perspective and there was discussion of the information amongst the panelists and participants. As some of the information contained in the September 4, 2012 Final Report reflects the utility perspective discussion, CREDA is offering the following observations on the report.

As you read the following observations, please keep in mind that the stakeholder participants in the workshop have not been provided the specific charge or assignment given to the panel participants, so the following comments are based on our assumptions derived from reading the final report. We would welcome an opportunity to discuss the report with you or your staff to have a better understanding as to the task(s)/question(s) the panelists were asked to consider during the workshop and in preparation of the report. We are offering the following technical comments on the report, as well as offering a perspective on how the report may affect collaboration within the Glen Canyon Dam Adaptive Management Program (AMP).

1. Stated Objective Versus Resultant Work Product

In the last paragraph of the introduction on page 6, the author(s) state that their role was "to review the GT Max model and its uses for economic analysis of issues relevant to the Glen Canyon Dam Adaptive Management Program." We are unable to understand how the report addresses that objective; rather, the report emphasizes a formal, centralized electric market advocacy position.

Rather than being a constructive, useful tool to assess applicability of GT Max for AMP applications, the tone and content of the report are quite different than the actual workshop discussions among the participants. The report appears to focus on what the model *doesn't* do, and what WAPA *doesn't* do in fulfilling its statutorily mandated mission, as opposed to assessing the model's applicability to AMP applications.

2. Concept of Peer Review

It was our understanding that a purpose of the workshop was to provide a peer review of the GT Max model. We think that a peer is a person who has equal standing in some respect. We believe that the object of the federal government's peer review process is, generally, to obtain an objective assessment of a body of work by a person who has a similar expert understanding about the subject, or body of work, as the person or persons who perform the work that is being peer reviewed.

As stated in the report, GT Max is a production cost simulation model. Employees of WAPA and Argonne who presented information at the workshop and use the model in the conduct of daily business responsibilities are production cost simulation experts, with very specific, special knowledge and experience in dealing with the complicated nuances associated with CRSP hydro system operation.

Based on many statements/conclusions/recommendations contained in the report, it appears to us that the author(s) may not be production cost simulation experts. Consequently, we are not convinced that an actual peer review has occurred. As pointed out by the author(s), there are a number of production cost models being used in the United States, and a large body of literature about the subject.

We may be misinformed as to the purpose and scope of the workshop and role/charge to the panelists, but possibly that could be resolved if such information is made available.

3. WAPA's Statutory and Contractual Obligations

In various places throughout the report, the author(s) suggest that WAPA should seek to improve its *profit* position, increase net revenues, bid its generation into California's ancillary services market, maximize revenues, and other similar ideas.

These suggestions signal a lack of understanding about the Colorado River Storage Project Act, WAPA's statutory obligation, delivery obligation concepts such as contract rate of delivery and sustainable hydropower, and WAPA's contractual delivery obligations to existing customers.

In short, WAPA's CRSP resources are already fully dedicated to existing contractual obligations, regardless of any year's specific Colorado River basin hydrology (wet or dry). And WAPA's statutory obligation is to market federal project hydropower at the lowest possible rates to consumers consistent with sound business practices. Those rates are structured to recover 100% of the construction and O&M costs allocated to power AND to repay a significant amount of the investment in irrigation projects in the upper Colorado River basin. That irrigation repayment obligation alone sets WAPA apart from any other power marketing administration.

In our view, WAPA has neither the resource flexibility nor the discretion needed to pursue the author(s)' suggestions in a way that would have a material impact on either WAPA or western region electric business economics.

It is our opinion that these comments/recommendations are out of scope (as we understand it) and unfortunately could lead to a serious misunderstanding of these issues by AMP stakeholders. If there is a basic misunderstanding of these issues amongst the AMP stakeholders, it makes collaboration and consensus building, already a challenge, much more elusive.

4. Centralized Market Effectiveness in the Western U.S.

As reflected in the report, a viewpoint of at least one panelist during the workshop was that formal, centralized markets are the panacea solution for all electric business problems, and that WAPA can materially improve its economic welfare through increasingly robust participation in such markets.

An assessment of actual historic experience in the Western U.S. suggests that retail customers in California have not benefited from the presence of the centralized market in that state.

The analysis included with this email transmittal (attachments 1-3) compares the change in prices for the California Independent System Operator (CAISO) participants between 1995 (the year prior to CAISO launch) and 2010 (the latest year for which information was available at the time the analysis was done) versus the change in prices in other Western States where no centralized markets exist.

The essential message of all three attachments is that the organized wholesale market in California has not served to provide bottom line retail cost benefits to consumers relative to electric business management in other Western states during this 15 year period.

While conceding that near-term costs for consumers will go up, a March 16, 2012 DOE Secretary of Energy Chu memorandum expressed the belief that in the long run, consumer costs would go down as a result of centralized market formation. From the perspective of many of WAPA's customers, centralized markets may not be "the" answer.

As with item 3 above, we believe that this portion of the report is out of scope and could lead to a flawed understanding by AMP stakeholders and readers of the report.

5. <u>Revenue Versus Cost</u>

In addition to numerous references to maximizing revenues and improving profits, the author(s) state that "minimizing costs may not be the most important objective", and proceed to suggest that maximizing revenues would constitute a mathematically equivalent approach.

From a WAPA customer perspective, we believe that there is a significant policy-level difference between a statutory obligation that requires WAPA to market federal project hydropower at the lowest possible rates to consumers consistent with sound business practices, and a revenue maximization goal.

On one hand, the author(s) correctly observe that the objective function of the GT Max model is to minimize cost. In this regard, we believe that WAPA and Argonne have correctly oriented the tool so as to be reflective of WAPA's legal obligation.

On the other hand, the author(s) describe the business area where 100% of WAPA's customers reside as "the regulated IOU business model", which suggests to us that the author(s) may not understand the public power characteristics of WAPA's customers.

The foregoing observations notwithstanding, the real damage in the revenue versus cost discussion is the promulgation of the misleading suggestion that utility business entities (WAPA, WAPA's customers, other public power entities, IOUs, etc.) are exclusively focused on maximizing *profits*. This is particularly harmful in the AMP arena, where the majority of participants are not utility business professionals, and a perception that "profits trump natural resources" could be reinforced.

As in items 3-4 above, the promotion of false perceptions such as this serves only to establish or strengthen barriers among AMP stakeholders who might otherwise be able to collaborate more effectively.

6. <u>Capacity Expansion Algorithms</u>

The report's author(s) suggest that the absence of a capacity expansion algorithm is a weakness of GT Max for the "types of analyses that Western is considering".

In contrast, our understanding of WAPA's scope of federal responsibility and mission is such that we do not understand why such modeling capability would *ever* be needed. WAPA has no retail obligation to serve, and no load growth responsibility. In analyses of alternative Glen Canyon and other CRSP hydro system flow regimes, the prospect of federal construction of new generating capability to offset capacity lost due to flow regime changes has, to our knowledge, never been contemplated.

Institutions that are in the business of using production cost models to forecast and study projected future generating system operation and costs (because they have the responsibility to plan for the future electric service requirements of their retail customers) do not use capacity expansion algorithms, and consider doing so to be an academic exercise that is not particularly helpful to the conduct of real world decision-making.

Finally, we think the suggestion that a capacity expansion algorithm is necessary to the production of superior electric price forecast information in future years for the valuation of capacity is not valid.

7. Other

There are other technical errors in the report. For example, the statement on page 21 that "the failure of a substation transformer or transmission line at one of the dams" (referring to Hoover and Glen Canyon) "takes out the entire project" is incorrect. The CRSP (Glen Canyon) and Boulder Canyon Project (Hoover) are separately authorized and marketed projects. Further, the Boulder Canyon Project does not have associated transmission, and the transmission system(s) used to market its output are not automatically "taken out" by a transformer failure or transmission line in the CRSP project (and vice versa).

We are available to discuss these observations with you or your staff, the panelists, and/or the author(s) of the report. Please don't hesitate to contact me at 480-477-8646, or Dave Slick at 602-236-2082.

Sincerely,

/s/ Leslie James

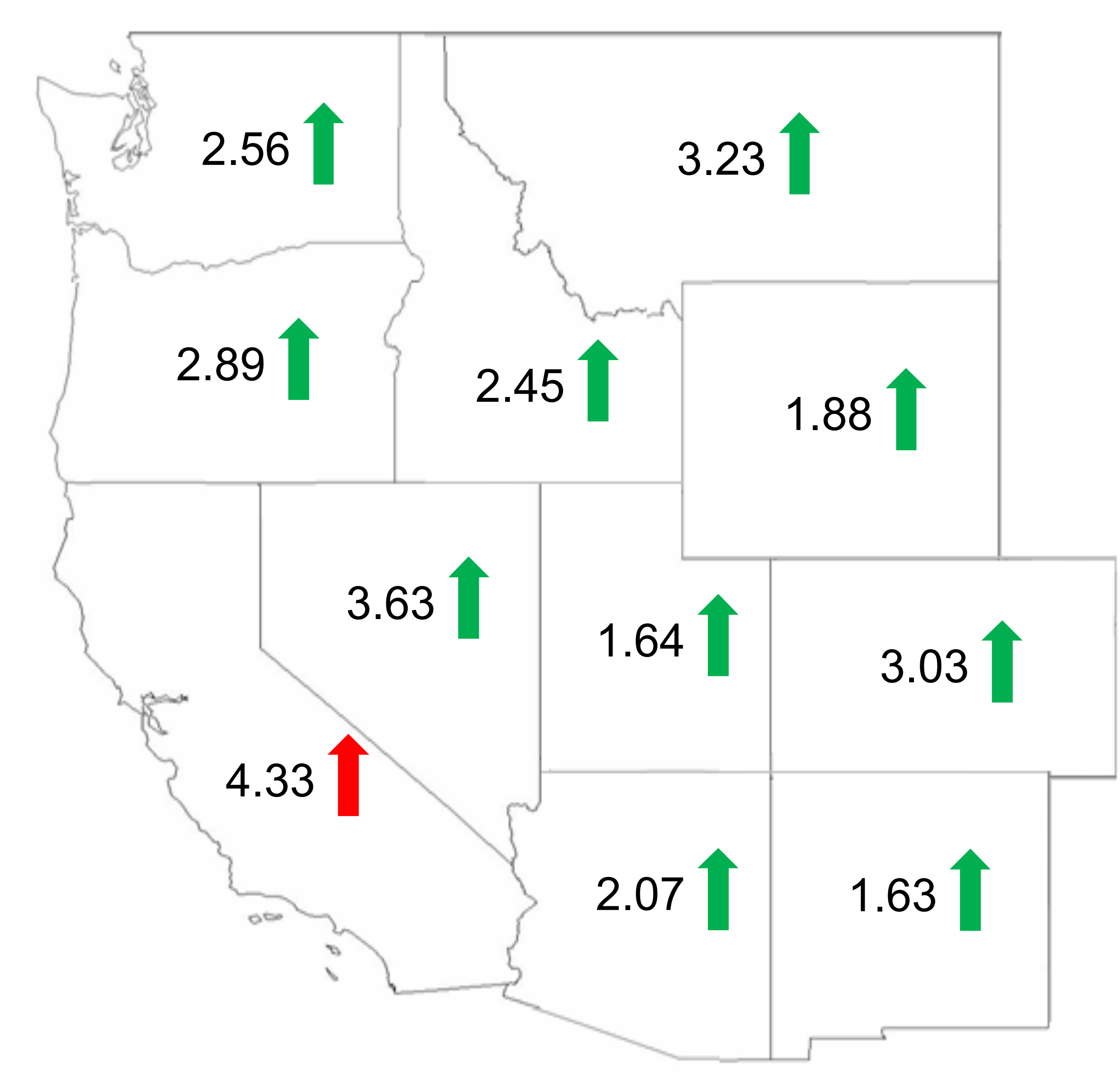
Leslie James
Executive Director

Cc: CREDA Board
Darren Buck – WAPA

Att: 4 attachments to email transmittal

Western States Retail Electric Price Information

Figure 1: Cent / KWh Increase Between 1995 and 2010



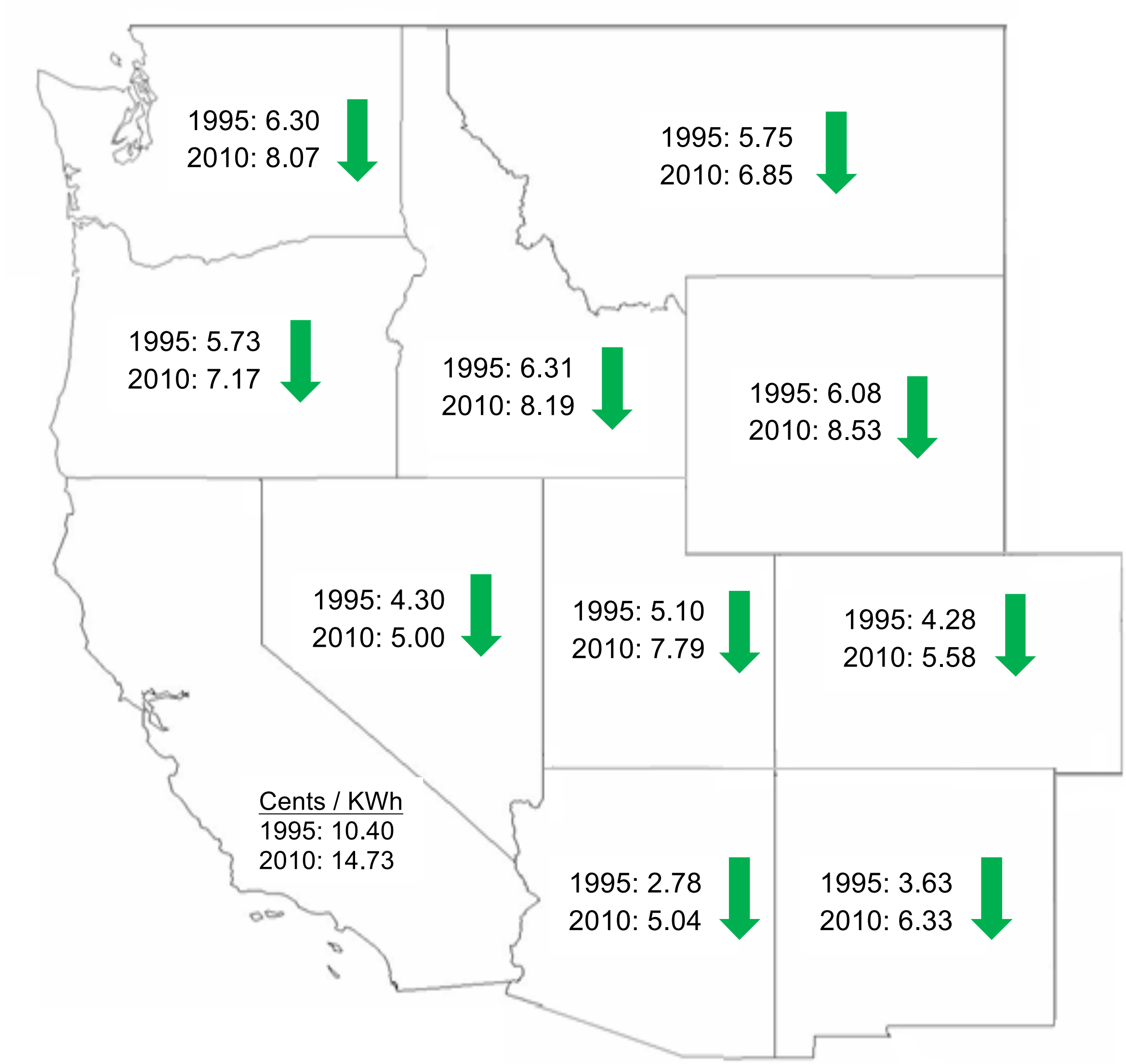
Description
Figure 1 displays the retail electric price increase in each state between 1995 and 2010 as measured in cents per kilowatt hour (Cents/KWh). For example, in Idaho the retail electric price in 2010 was 2.45 cents/KWh higher than the retail electric price in 1995.

Message
The retail electric price increase in California between 1995 and 2010 was significantly higher than every other Western state. The organized wholesale market in California (CAISO) did not serve to provide bottom line retail cost benefits to consumers relative to electric business management in other Western states during this 15 year period.

Details
The Energy Information Administration (EIA) was the source for all data. California prices represent the average of those California entities that are CAISO transmission owners and serve retail customers (PG&E, SCE, SDG&E, Anaheim, Azusa, Banning, Pasadena, Riverside and Vernon). The investor owned utilities (PG&E, SCE, SDG&E) represent 96% of retail sales made by these entities.

Western States Retail Electric Price Information

Figure 2: Cent/KWh Differences Between California Electricity Prices and Other States



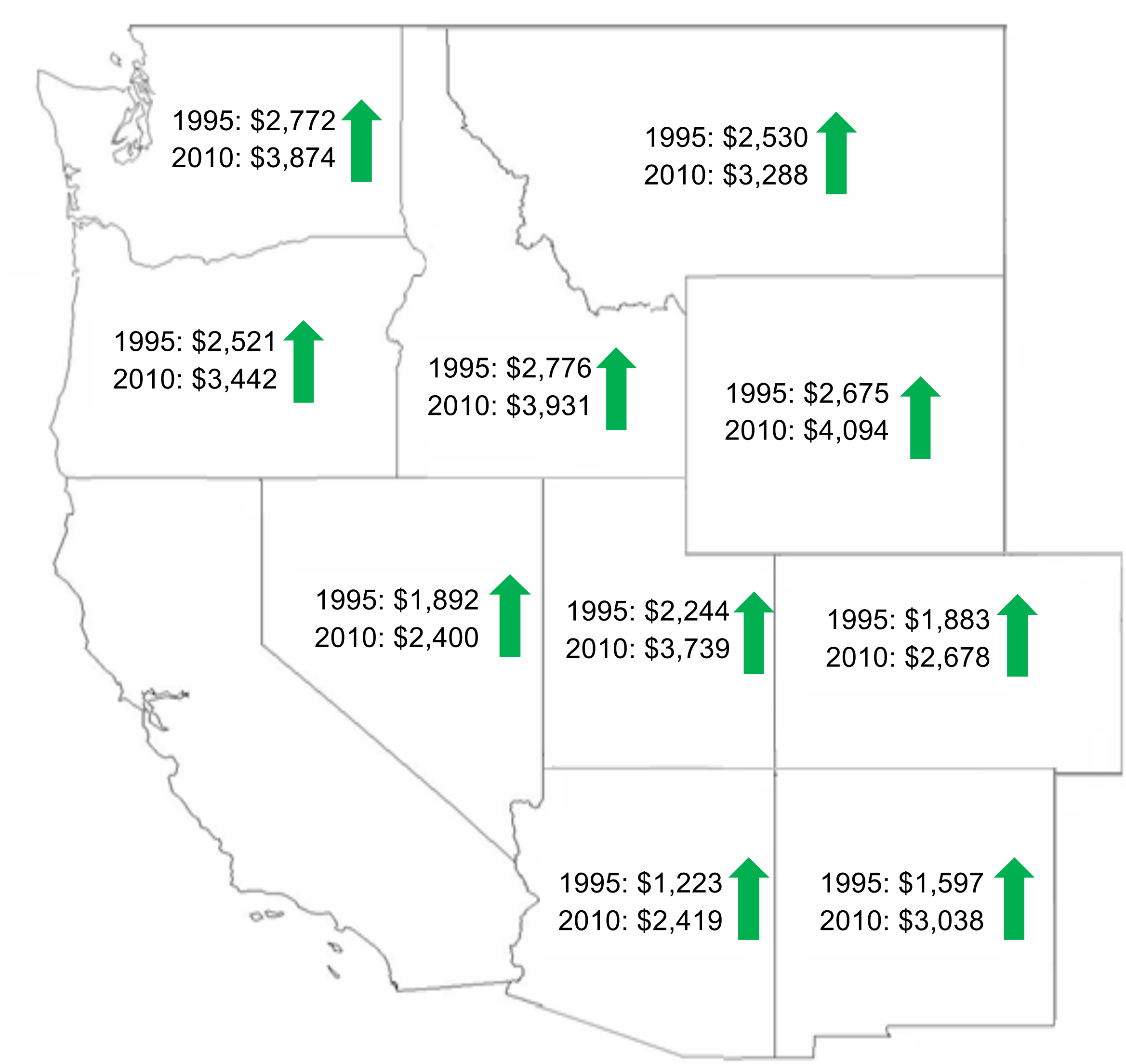
Description
Figure 2 displays retail electric price differences between California and other Western states during 1995 and 2010 as measured in cents per kilowatt hour (Cents/KWh). For example, in 1995 the retail electric price in Utah was 5.10 cents/KWh lower than California, and in 2010 the retail electric price in Utah was 7.79 cents/KWh lower than California.

Message
In 1995 retail electric prices in other Western states were significantly lower than retail electric prices in California, and by 2010 the gap between retail electric prices in other Western states and California had widened. The organized wholesale market in California (CAISO) did not serve to provide bottom line retail cost benefits to consumers relative to electric business management in other Western states during this 15 year period.

Details
The Energy Information Administration (EIA) was the source for all data. California prices represent the average of those California entities that are CAISO transmission owners and serve retail customers (PG&E, SCE, SDG&E, Anaheim, Azusa, Banning, Pasadena, Riverside and Vernon). The investor owned utilities (PG&E, SCE, SDG&E) represent 96% of retail sales made by these entities.

Western States Retail Electric Price Information

Figure 3: Annual Savings For A Family of Four Relative to California Electricity Prices



Description

Figure 3 displays the dollars that a family of four in other Western states saved relative to a family of four in California that consumed the same amount of electricity in 1995 and 2010. For example, in Colorado a family of four saved $1,883 in 1995 and $2,678 in 2010 relative to a family of four in California that consumed the exact same amount of electricity in those years.

Message

For the same amount of electricity, the cost for a family of four in 1995 in all other Western states was lower than that for a family of four in California, and by 2010 the gap between California and other Western states had widened. The organized wholesale market in California (CAISO) did not serve to provide bottom line retail cost benefits to consumers relative to electric business management in other Western states during this 15 year period.

Details

The Energy Information Administration (EIA) was the source for all price data. California prices represent the average of those California entities that are CAISO transmission owners and serve retail customers (PG&E, SCE, SDG&E, Anaheim, Azusa, Banning, Pasadena, Riverside and Vernon). The investor owned utilities (PG&E, SCE, SDG&E) represent 96% of retail sales made by these entities.