RTO West
Benefit/Cost Study

Final Report Presented to RTO West Filing Utilities

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EXECUTIVE SUMMARY

Tabors Caramanis & Associates (TCA) was contracted by the filing utilities proposing to establish a Regional Transmission Organization (RTO) for the Pacific Northwest (RTO West) to undertake an analysis of the probable benefits and costs of RTO West. The goal of the filing utilities was to provide to all stakeholders an independent quantitative and qualitative analysis that would offer insights regarding the relative merits of establishing RTO West, and its related influences on the commercial, wholesale markets.

The TCA Energy Impact Analysis focused on identifying the patterns of energy transactions and energy flows that would take place *only* with the existence of RTO West—patterns that would be the direct result of increased engineering, economic, and organizational efficiencies arising from the establishment of RTO West. The analyses demonstrated how the behavior of the northwest transmission and energy systems is impacted by market structures, without and with an RTO, and how various market characteristics associated with these two contrasted structures are believed to impact future prices for electricity in the northwest.

The TCA analysis effort, which was conducted from September 2001 through February 2002, was overseen by a northwest stakeholder group which was made up primarily of representatives of the filing utilities and of other interested parties, e.g., representatives of direct service industries, public power systems within the region, and representatives from outside of the RTO West "footprint", e.g., Canada and California. The group provided overall guidance to TCA in defining the scope of work, developing the input assumptions, validating the results, and determining which sensitivity cases were evaluated.

Areas of Study

TCA's analyses covered four principal areas.

1. TCA carried out an Energy Impact Analysis (a simulation analysis) of the engineering economics of operation of the RTO West region and the Western Systems Coordinating Council (WSCC), with and without the existence of RTO West. The study used a simulation tool, GE MAPS, to analyze energy flows, market dynamics, and energy pricing. The energy impact simulation quantified economic benefits across the RTO West grid and the WSCC resulting from the following:

   - Elimination of pancaked transmission rates.
   - More efficient, regional utilization of generating resources.
   - Elimination of pancaked transmission loss charges.
   - Access to a broader market for operating reserves.
   - Increased scheduling efficiency of transmission capacity (through reduced requirements for contract path scheduling limits).

The analysis examined the marginal price of energy to determine the impact to the energy value loads pay and the revenues generators receive. TCA used the GE MAPS modeling system to simulate the operating behavior of the western power system both with and without the existence of RTO West[1]. GE MAPS provides an analytic tool with which to simulate the hourly physical and economic behavior of the power grid. With this system it was possible to model the transactions and flows of energy that would result from the existence of an RTO West agreement in which there was a single tariff for energy flowing in the RTO West system. The effect modeled was to reduce the economic barriers to trade within the region that in turn reduces operating costs and increases flows. A set of input assumptions was mutually agreed upon by the study group.

The analysis calculated, on an hourly basis, the spot market price at each major transmission bus in the west. The analysis quantified the changes between a status quo case (Without RTO case), and a modeling case where structures were changed to represent the operations with an RTO in place (With RTO case). The detailed representation of these "Base" cases is provided in the report.

In addition, several sensitivity cases were performed to isolate benefit drivers and test sensitivities to varying market conditions. These included the following cases:

- Physical System Cases:
  - Low Water Year/High Gas Price
  - New Resource Additions in Montana

- Benefit Driver Cases: With RTO case rerun with each of the following items fixed respectively
  - Loss charged as in Without RTO case
  - RTO export fees set to zero
  - Transmission scheduling limits as in Without RTO case
  - Maintenance schedule as in Without RTO case
  - Isolate the impact of operating reserves

2. TCA carried out benchmarking analyses to estimate the costs of operating an RTO, operating a secondary exchange, market participants' acting as a Schedule Coordinator, and of impacts of lost load due to unplanned outages or impacts of reductions in unplanned outages.

3. TCA conducted qualitative evaluations of further potential impacts of implementing an RTO. These addressed the following areas:

   - RTO focus, coordination, and information exchange.

[1] Note that GE MAPS is a product of the General Electric Corporation, Schnectady, NY. GE MAPS is a Security Constrained Dispatch Model. It calculates the optimal (least cost) dispatch of all generators within the studied system subject to transmission constraints and subject to the possibility of operating outages, hence the description, "Security Constrained Dispatch."

- RTO consolidation of functionality.
- Organizational relationships established by the RTO.
- RTO independence.

4. TCA carried out an analysis of market concentration in the northwest that determined levels of market concentration with and without RTO West.

Findings

TCA's results include benefits and costs (both in terms of Energy Impacts and unquantified benefits) and effects on market concentration.

(A) Benefits

(1) Energy Impact Benefits

The Energy Impact Analysis undertaken by TCA estimates system benefits from two related areas: (1) direct savings in operating costs and (2) system benefits that would result from reduced transmission system congestion.

In the core analysis of the study, the "Base Case" analysis, the 2004 annual marginal cost to serve load under the locational pricing structure proposed for RTO West and modeled in the TCA analysis decreases in the northwest by $1.3 billion[2] as a result of putting in place RTO West. At the same time, the lower prices result in lower generator net revenues of approximately $900 million. The difference between the loads' cost reduction and the generators' net revenue reduction represents the net societal benefit of $305 million for the RTO West region and $410 million for all of the WSCC.

The Energy Impact Analysis further provides insights as to the nature of the overall system cost reductions. For the WSCC,[3] of the $410 million difference between the decreased cost of energy to serve load and the decreased generator net revenues, approximately $239 million represents savings in production costs, predominantly arising from greater efficiency in operations that reduce fuel costs. The balance of the $410 million benefit in WSCC, approximately $171 million, represents the calculated value of decreased congestion costs.

In a locational, marginal-priced energy system (as is envisioned for RTO West), the value[4] of reduced transmission congestion goes beyond the value of the reduction in production costs alone. The same phenomenon is also seen in the RTO West region. TCA's analysis shows the significance of the congestion costs in the northwest. If users

[2] US dollars are used throughout this report, unless otherwise noted.
[3] The WSCC is used here as example. The analysis modeled the entire WSCC, but across the WSCC generation and consumption is balanced in both cases. Within the northwest region, the model shows that the exports increase out of the northwest in the With RTO case, making quantification of the exact attribution of the benefits impossible. The sensitivity cases help to identify the component drivers of the benefits. These are presented in detail in the body of the report.
[4] In such a system, the "value" of the congestion is deemed to be equal to the product of (1) the value of a constrained path and (2) the flow of energy across the path.

were required to pay for the marginal cost of congestion rather than only average or incremental cost, as is the case at present, the costs they incurred would be $171 million less with RTO West than without.[5]

In addition to representing a shift in the cost of managing congestion, the impact can perhaps more importantly be seen as enabling the transmission providers to spend less on transmission reinforcements than would otherwise be needed to counteract high-cost congestion. In this sense, the analysis suggests that a change in generation dispatch enables the region to capture a significant opportunity to avoid needed (transmission) capital expenditures of up to $171 million.

The $171 million congestion impact and the $239 million operating cost savings are demonstrated by the base case analyses.

The sensitivity analyses suggest there are two primary benefit drivers, which reflect the modeling techniques. The pancaked rates seem to have a strong bearing on benefits; by reinstating pancaked loss charges alone, net benefits dropped nearly 40% (to $255 million), with all of this reduction ($157) in the area of reduced congestion rent savings. This sensitivity case was the only case significantly impacting congestion rent savings. Similarly, operating reserves seem to be the only attribute tested that had a strong effect on production cost benefits. The efficient allocation of operating reserves also has a strong bearing on total benefits: isolating the impact of operating reserves showed over 60% reduction in production cost savings (from $239 million to $90 million).

The Energy Impact Analysis is relatively insensitive (4% or less impact on total benefits) to other tested attributes, including maintenance scheduling, contract path scheduling limits, export fees, and low hydro conditions.

From the sensitivity runs, TCA draws the following broad implications:

- Generally, the domination of the northwest system by hydroelectric power provides a relatively efficient bulk power system to begin with;
- Pancaking therefore has a greater impact on the congestion prices across constraints than it does on overall production cost efficiency;
- The ability to further substitute hydro resources for thermal resources for operating reserves, through further regionalization, offers significant benefits.

[5] If the marginal value of congestion were valued explicitly today, the great majority of the congestion costs are borne by the Transmission Owners (TOs). Moving to the RTO structure in this framework would result in a transfer of $180 million cost away from the TOs (or possibly transmission rights holders in an RTO world) and to the loads and generators in the With RTO case.

(2) Qualitative Benefits

A variety of other benefits were identified through industry literature and marketer surveys. Many of these benefits are generally viewed to be material, although the study did not quantify potential values. The following areas were addressed in the analysis:

- Planned outage management may provide more accurate assessments of the effects of proposed maintenance.
- Reduced failure propagation: tightened communications and coordination may reduce conditions that cause failures to propagate.
- Voltage/frequency management: broader information and broader control of transmission and generation resources may reduce voltage and frequency problems.
- Loop/parallel path flow: may provide better management of loop flow through improved access to region-wide information and region-wide scheduling authority and through more efficient pricing of congestion.
- Scheduling, system monitoring, checkouts, and settlements: traditional information exchanges, such as checkouts and interchange accounting, will no longer be required.
- Consolidated control area operation and impacts on reserves and transmission capacity may result in likely increases in available transfer capacity (not captured in the Energy Impact Analysis), reduced requirements for automatic generation control, and sharing of reserves beyond those captured in the Energy Impact Analysis.
- Real-time balancing efficiency may result in a simplification of, and improved efficiency associated with, the balancing function.
- Long-term planning and expansion: long-term transmission and generation additions are likely to be more efficient.

(B) Costs

(1) Benchmarking Costs

TCA's benchmarking analyses focused on identifying the expected annual costs of establishing and operating the RTO itself. On average, the analyses show that the cost to operate an RTO would be approximately $0.45 to $0.51 per MWh, or $127 to $143 million per year, including the amortized startup costs of the RTO.

The study also examined market participants' potential costs associated with using an secondary exchange and explored the costs of establishing a Schedule Coordinator role for market participants to interface with the RTO. Market participants in the northwest scheduling energy within the RTO can trade energy through an exchange for approximately $0.10 per MWh, and can receive Schedule Coordination services, for $0.065 to $0.08 per MWh.[6] It is noteworthy that the costs of using an exchange, or

[6] These are the fees of the Automated Power Exchange. Some market participants are likely to be able to provide the service within their organizations for much less than this.

drivers to use an exchange, for the most part also exist absent the RTO. Similarly, many of the functions of Schedule Coordination are being conducted today within organizations.

(2) Qualitative Costs

Additional unquantified costs may include the following:

- Generalization costs—the potential loss of unique expertise currently supported by operating smaller, individual transmission systems.
- Complexity costs—additional costs or externalities, beyond the Schedule Coordination role, required to support the RTO structure.

(C) Impacts on Market Concentration

The market concentration analysis indicates the following:

- As a result of maintaining primarily vertically integrated structures, all electricity markets in the RTO West region are highly concentrated, suggesting the potential for—but not necessarily existence of—the exercise of market power.
- The degree of market concentration is not materially affected by the implementation of RTO West.

Assessing Overall RTO Impacts

Although the several study areas reported on here cannot necessarily be collapsed to produce a single conclusion on the quantitative merits of implementing RTO West, the magnitude of the potential savings reported in the Energy Impact Analysis, relative to the industry costs of RTOs, suggests that the benefits could outweigh the costs. The qualitative impacts—predominantly benefits—would tend to strengthen this conclusion. It is the northwest's producers and consumers, however, who must ultimately determine whether the sum of the quantifiable and unquantifiable benefits are greater than the economic and social costs.

1 Organizational Outline

This report is organized as follows.

Section 2 provides background and context for this benefit/cost study.

The largest aspect of this analysis is the assessment of RTO West impacts on energy flows, market dynamics and energy pricing through the use of the quantitative generation and transmission simulation model, GE MAPS. Using the GE MAPS modeling system, this analysis produced quantitative analytic results based on the economic and physical operation of the regional power system. The impact study approach, detailed assumptions, and base case and sensitivity results are presented in Section 3.

TCA performed quantitative benchmarking analyses for other benefit/cost elements, such as RTO, and exchange and Schedule Coordination costs. The benchmarking elements are presented in Section 4. Qualitative investigation of other potential impacts of an RTO is outlined in Section 5. Section 6 contains the Market Concentration study, including approach and findings.

In order to provide a manageable printed document, detailed (and voluminous) output data associated with the Energy Impact Analysis and the market concentration study have not been included with this report. These data are available for electronic downloading on TCA's web site at www.tca-us.com/publications when made publicly available by RTO West.

2 Background

The Benefit/Cost Study was commissioned by RTO West Filing Utilities for the purpose of evaluating the qualitative and quantitative implications of developing and implementing RTO West.

A previous benefit/cost study[7] was performed by a northwest stakeholder study group using the modeling tool AURORA. Assumptions in that energy analysis included the use of average water conditions and transactions at market clearing prices. The AURORA model did not attempt to reflect dynamic congestion management[8], and although the modeling effort identified some benefits due to removal of pancaking transmission rates, the modeling results did not produce reliable conclusions about the benefits and costs.[9] The previous study also addressed RTO costs by developing an expected budget for RTO West, and it identified savings expected from lower quantities of regulating reserves being required under an RTO.

The Filing Utilities established a work group which involved Filing Utility representatives and other interested parties for the purpose of scoping the Competitive Solicitation, interviewing and selecting project consultants, scoping the evaluation, defining and specifying assumptions and data input, specifying sensitivity analyses and evaluating results. The stakeholder work group directing the present benefit/cost study selected a study methodology that included a detailed modeling of the transmission system and that looked into other benefit and cost impacts of RTO West in more depth. The stakeholder group conducted a competitive selection process in the summer of 2001, worked with TCA to develop a detailed scope of work, and contracted with TCA to perform work under this scope in November 2001.[10] Following those initial steps, TCA and the study group worked closely to develop the assumptions to be used in the analyses.

TCA presented the results of its preliminary analyses on February 4, 2002.[11] TCA and the study group reviewed the results, refined the assumptions, and identified sensitivity cases to be run. This report presents the results of the ultimate modeling activities and the complete results of the other benefit/cost elements.

[7] RTO West Potential Benefits and Costs, October 23 2000.
[8] Op Cit. p 5.
[9] Op Cit, p 23.
[10] Posted at http://www.rtowest.org/Stage2BenCstMain.htm
[11] Ibid.

3 Energy Impact Analysis: GE MAPS Study

TCA conducted a quantitative analysis of the WSCC system under two scenarios: a status quo case in which RTO West is not implemented ("Without RTO") and a case in which RTO West is implemented ("With RTO"). The Energy Impact Analysis used the GE-MAPS model[12], which incorporated the operating procedures and contractual and physical transmission constraints currently used or proposed for the WSCC. The analysis provides insight into the theoretical economic operation of the WSCC markets With and Without RTO.

The analysis shows that there are economic efficiencies to be realized by regionalizing the operation of the electric power market. These results are based on input assumptions that the RTO West Benefit Cost Work Group (work group) considered as reasonably expected conditions for the year 2004 (including the current RTO West proposal, fixed hydro schedules, and economically efficient markets with marginal cost bidding). Most realistically, the benefits fall within a range, and these results show the expected value of benefits given the base-case assumptions. The results of the sensitivity analyses are presented, and they offer insights into the sensitivity of the results to certain assumptions and the relative drivers of the benefits.

3.1 Expected Benefits of RTOs

The economic benefits of RTOs are many, including the following:

- Increased economic efficiency from eliminating pancaked[13] transmission rates and pancaked transmission loss charges;
- Sharing of operating reserves;
- Improved congestion management and internalization of loop flows;
- Coordinated maintenance and scheduling of generation and transmission;
- Increased competitiveness of markets;
- Lower transaction costs (one-stop shopping) and simplified business practices, especially for small players;
- Increased ATC over major transmission lines; and
- Other economic benefits such as coordination of system expansion and planning, adoption of a single OASIS site, and improved reliability on a regional basis.

Economic efficiency, sharing of operating reserves, and improved congestion are addressed as part of this Energy Impact Analysis. The other benefits are addressed qualitatively in Section 5 of the report.

[12] GE-MAPS is a Multi-Area Production Simulation Software developed by General Electric Power Systems and proprietary to GE.
[13] "Pancaked" refers to the additive nature of the charges when energy is transported across multiple transmission areas.

3.2 Measuring Benefits with the Energy Impact Analysis

Two metrics were used in the Energy Impact Analysis to quantify the benefits of RTOs:

1. Production cost savings (fuel and variable Operating & Maintenance costs)
2. Social welfare (consumers' and producers' surplus) benefits.

The social welfare, consumer and producer surplus are economic terms that are often used in cost/benefit analyses. It is assumed that a decision is economic or cost-effective if the net increase in social welfare exceeds the cost. In practice, this concept is applied by governments to aid decisions that affect society, e.g., in deciding to build roads or preserve wilderness areas, in building recreational sites, or requiring environmental mitigation measures. This concept is very useful because it shows the impact on the society as a whole rather than on a portion of it. For example, lowering energy market clearing prices in any given area could reduce generators' profits, but, on the other hand, it reduces load payments. If the measure is only producers' surplus or producers' benefit, then lowering energy prices might seem harmful, and lowering energy prices is a bad idea; however, if we look at both sides of the equation and there are net benefits, then lowering prices is a good idea. Also, using this concept avoids the problem of allocating the benefits or deciding who is getting the benefit and thus avoids dealing with regulatory and contractual issues that determine how the benefits get allocated. Throughout the analysis in this report the impact on consumers and generators is determined separately, as well as the net impact on society.

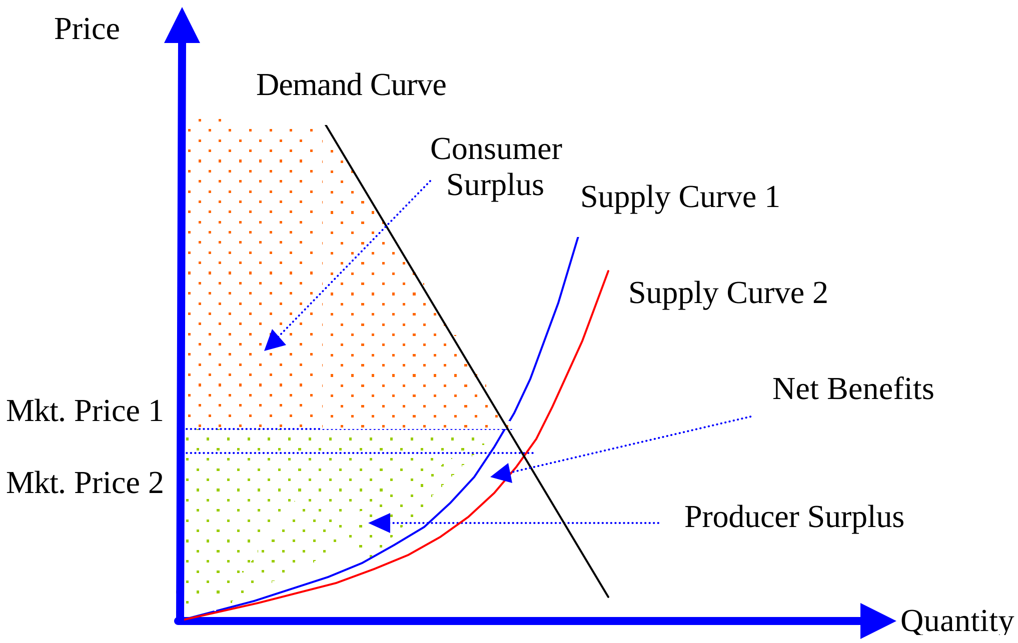
The social welfare is expected to be the same as the production cost savings because inelastic demand was used in the model and thus demand is fixed and the same in both With and Without RTO cases. Additionally, there are three players in this market: consumers and producers of energy, and the transmission rights owners. The impact of implementing RTO on these three players is quantified.

To illustrate how to quantify the benefits of RTOs using these metrics, consider how eliminating pancaked transmission rates increases economic efficiency:

> *Production cost savings:* Eliminating pancaked transmission rates increases the economic efficiency of dispatching generation resources to meet demand at lowest cost, and thus lowers the total cost of producing electricity. Without pancaked transmission rates, during peak hours, for example, high-price areas could buy available steam gas-fired generation from other areas instead of starting a more expensive peaking unit. With pancaked transmission rates, this peaker would have been more economical given the added cost to move power from the steam unit, even though it is much less efficient than a steam gas-fired unit or a combined-cycle unit.

Social welfare benefits: Consider the supply and demand curve in Figure 1. As the supply curve shifts right due to more economic dispatch of generation resources, there is a net increase in both consumer and producer surplus. Eliminating pancaked transmission rates will increase market prices in some areas and decrease prices in other areas. Producers benefit in increased-price areas, while consumers give up value, and vice versa for areas with lower prices. Thus, consumer surplus increases in areas where prices go down and producer surplus increases in areas where prices increase. The net benefit to both consumers and producers in all areas is the increase in social welfare. In addition, exporting areas will realize a net benefit even when prices go up, since generation exceeds demand.

Figure 1: Producer and Consumer Surplus



Similar to eliminating pancaked transmission rates, eliminating pancaked loss charges increases economic efficiency. Currently, most regions have tariffs that include charges for losses based on average loss factors. When transactions cross more than one control area, these loss charges are pancaked. Eliminating the transmission loss charge pancaking, and charging for losses on a regional basis instead, eliminates the penalty effect of moving energy within RTO West and would increase the economic efficiency of dispatching generation resources.

Sharing operating reserves across the RTO West region also leads to lower operating costs. Carrying reserves on the most efficient resources over a wider region will lower operating costs. Take the example of a system with large hydro generation, which is able to carry spinning reserves at a much lower cost than a system with mostly thermal units, and this benefit could be shared among systems that have predominantly hydro generation and systems that have predominantly thermal generation.[14]

Another benefit of RTOs is improved congestion management and internalization of loop flows through the elimination of contract path scheduling. Current contract path limits are set to protect the system in the absence of centralized control and an information collection center. The objective of these contract path limits is to limit the impact of loop flow on neighboring control areas by assuming that there are no loop flows. Eliminating contract path scheduling limits increases the utilization of the transmission system, reduces total production cost, reduces transmission congestion cost, and lowers locational prices.

3.3 Using the MAPS Model to Determine Benefits

3.3.1 Basic Model Representation

The GE MAPS model is a security-constrained dispatch model that simulates the operation of the electricity market over time. It assumes marginal cost bidding,[15] performs a least-cost dispatch subject to thermal and contingency constraints, and calculates hourly, locational-based marginal prices for electricity. Zonal prices can be calculated either as load-weighted averages or as simple averages of locational prices. The congestion cost is calculated as the shadow price[16] multiplied by the power flow on each interface. Because it is reasonable to assume that real markets are not perfectly competitive, the simulated prices represent the lower bound of what actual market prices are likely to be.

The GE MAPS simulation is consistent with the congestion management scheme envisioned by RTO West. GE MAPS simulates the electricity market by dispatching resources to serve load in a least-cost manner. The bidding strategy that is assumed is based upon the marginal cost of generation and therefore reflects the locational marginal price of electricity at specific nodes; nodal data can be aggregated to whatever level (utility, region, state, etc.).

The GE MAPS simulation is also consistent with the RTO West pricing scheme, which is based upon a load-based, company rate concept. More specifically, the RTO West pricing scheme expects to collect most of the embedded cost of transmission facilities from loads, although a portion of the embedded costs are expected to be collected through transitional mechanism, called the Transmission Reservation Fee (TRF). GE MAPS

[14] The RTO should also enable lower reserve requirements, as discussed in Section 5, though the Northwest may already have reserve sharing agreements to take advantage of load and generation diversity. The Energy Impact Analysis did not assume any reductions in total requirements, but rather only considered the optimized dispatch of reserve resources.

[15] However, that assumption can be overridden, implementing strategic bidding behavior, but such effort is not trivial and the study group chose not to pursue this sensitivity case.

[16] The "shadow price" represents the marginal value of a constrained path and is calculated by GE MAPS.

applies the TRF ($3.60/MWh), plus a $0.20/MWh administrative fee, to all transactions that exit the RTO West footprint.

3.3.2 Input Assumptions

The following inputs assumptions were used in the Energy Impact Analysis:

- A load forecast based on most recent forecast as provided by RTO West.
- Fuel price forecasts based on the EIA forecast for natural gas.
- A transmission system configuration based on a load flow representation that includes all transmission upgrades for summer 2004, as provided by RTO West.
- Environmental adders based on expected NOx regulations for 2004.[17]

Details of these and other inputs to the model are described in Attachment 1.

In addition, the Energy Impact Analysis employed basic assumptions about commitment, given fees, and about capacity markets.

The RTO boundaries were defined based on today's boundaries for the California ISO, proposed boundaries/membership for RTO West, and proposed membership for WestConnect. Note that it was assumed that all utilities in the northwest participate in RTO West, **OR** that those entities that do not participate have no impact on the operation of RTO West.

TCA used a regional installed capacity market to accurately represent the transmission system capability, the fact that excess installed capacity in Alberta is not that useful to British Columbia, and so on. Each region was assumed to have a 16% installed capacity reserve margin requirement except Alberta and British Columbia, where an 18% reserve margin requirement was used. Note that TCA did not evaluate the impact of establishing RTO West on the Installed Capacity market clearing prices or the value of installed capacity if there are no explicit markets in the WSCC.

3.3.3 With and Without RTO West Scenarios

The Energy Impact Analysis base case compared two scenarios: a status quo case, assuming no RTO implementation in the northwest (Without RTO), and a case representing operations with RTO West in place (With RTO).[18] The RTO West benefits were deemed to be equal to the change in production cost and the change in producer and consumer surplus between the two cases.

The following represents a summary of the With and Without RTO cases. Detailed discussion for each major attribute is provided in the sections that follow.

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[17] By request of the RTO West benefit/cost study group, however, TCA did not include the NOx environmental adders in generators' simulated bid prices.

[18] In the With RTO case, an RTO in the Southwest was also modeled with similar market conditions to that represented for the RTO West.

The With RTO West market conditions were defined as follows:

- No pancaked transmission or loss rates, only a single region-wide wheel-out rate applied at the region boundaries;
- No contract path scheduling limits;
- Carrying reserve on most efficient resources within the entire RTO West region, with the reserve requirements based on the region's hourly load;
- Optimizing unit commitment and least-cost security-constrained dispatch on a region-wide basis (all generation resources within the RTO area);
- Scheduling maintenance of generation units according to regional load; and
- Hourly hydro generation predefined, based on average historic output; scheduling hydro generation (outside PNW) against regional load.

The Without RTO West market conditions were defined as follows:

- Pancaked transmission wheel-out rates (on company basis);
- Pancaked loss wheel-out rates;
- Contract path scheduling limits in place;
- Carrying reserves on individual company's units and requirements on company's hourly loads;
- Scheduling maintenance of generation unit according to individual company's loads; and
- Hourly hydro generation predefined, based on average historic output; and scheduling hydro generation (outside PNW) against company's loads.

Note that the first three characteristics in the preceding list represent financial or contractual characteristics, rather than being determined by the engineering characteristics of the power system.

3.3.4 Treatment of Wheeling Charges

In the With RTO case, wheeling charges for transactions, or energy flows, between different RTOs were modeled. In this case, power can be moved from any generator in an RTO to any load in that RTO without paying pancaked wheeling charges. However, there are wheeling charges at each of the RTO's boundaries (RTO West, California ISO, and WestConnect). Wheeling charges apply primarily to power flowing out of a region or control area (wheel-outs and wheel-throughs). A small number of utilities also had wheel-in charges.[19] It was assumed that in each RTO the load would pay its local transmission rate, irrespective of that load's source of electricity.

[19] This is the case for BPA and IID. For these entities the modeling assumptions were based on these entities' tariffs and discussions with BPA staff.

For the Without RTO case, wheeling charges were used for each existing transmission owner's service area, based on the rates filed in their transmission tariffs. These charges are assessed on wheel-out and wheel-through transactions.

Table 1 shows wheeling rates used in both the With RTO and Without RTO cases.

The following examples demonstrate the application of wheeling rates in the Energy Impact Analysis.

1. Generation located in the BPA area selling power off the BPA system pays BPA wheeling rates in the Without RTO case.
2. Generation located outside of BPA and delivering energy through and out of the BPA system is considered to represent a wheel-through and also pays BPA wheeling rates in the Without RTO case.
3. Energy moving from a BPA generator to a BPA load, on the other hand, is not assessed a wheeling charge in either case.
4. Generation from a BPA generator to a California load pays the pancaked wheeling charges along the least-cost path from BPA to California in the Without RTO case, and pays only the RTO West export fee in the With RTO case.
5. In the Without RTO case, a generator in Montana serving BPA load pays
    a. the Montana Power Company wheel out rate,
    b. the BPA Montana intertie, and
    c. the BPA network charge for wheeling into BPA[20] (BPA network and intertie rates are pancaked. The same is true for the southern intertie.)
6. In the With RTO case, the above generator in Montana selling to BPA incurs no wheeling charges.

An in-area transmission service charge is not explicitly modeled for the following reason. The load pays the transmission service charge irrespective of where its power originates, and thus the transmission service charge is a sunk cost that should not affect the dispatch decision. In both the With RTO and Without RTO cases, the loads are exactly the same. Thus, transmission service payments by in-area loads will not be impacted by other aspects of the cases. Therefore not modeling such payments has no impact on the outcome of the modeling or the collection of load-based transmission revenues.

The revenues from wheeling charges differ between the With RTO and Without RTO cases. Considering wheeling charges internal to RTO West, there may be a cost shifting *among* RTO West members but zero impact on net benefits *across* RTO West. There is a wealth transfer to/from the RTO West, the CA ISO, and the Southwest RTO only to the extent that total export charge revenues differ in the With RTO and Without RTO cases.

[20] TCA tested this assumption by setting the wheeling-in charges to zero for both BPA and IID. The results of this simulation show a deminimus change in either total production cost savings or WSCC-wide net savings.

TCA did not quantify the impact of the changes in wheeling rates into and out of RTO West as part of the RTO West benefits.[21]

Table 1: Wheeling Rates Used in the With and Without RTO Cases

Wheeling Charges ($/MWh)

Region / Utility	*With RTO*	*Without RTO*	*Region / Utility*	*With RTO*	*Without RTO*	*Region / Utility*	*With RTO*	*Without RTO*
RTO West	3.80	0.00	California			WestConnect	3.00	0.00
Avista Corp.		1.50	PG&E - high voltage only	1.77	1.77	Arizona Public Service		3.50
Idaho Power Company		1.50	PG&E - low voltage	3.76	3.76	El Paso Electric		5.50
Montana Power Co.		4.48	SCE - high voltage only	2.05	2.05	Public Service of New Mexico		2.84
PacifiCorp		1.50	SCE - low voltage	2.28	2.28	Salt River Project		4.12
Portland General Electric		1.50	SDG&E - high voltage only	2.01	2.01	Texas-New Mexico Power	0.00	5.34
Puget Sound Energy		1.50	SDG&E - low voltage	4.85	4.85	Tucson Electric Power		6.52
Sierra Pacific Resources	0.00		California - Oregon Border (COB)	1.83	1.83	WAPA Lower Colorado		2.13
Zone A (Sierra Pacific Power)		3.92	Palo Verde intertie	2.03	2.03	WAPA Rocky Mountain		4.17
Zone B (Nevada Power)		1.66	Nevada - Oregon Border (NOB)	1.84	1.84	WAPA Upper Missouri		4.04
Bonneville Power Administration			Mead intertie (MEAD - WALC)	2.05	2.05	Imperial Irrigation District		1.00
Network		1.50	Victorville intertie	2.05	2.05			
Southern intertie		2.20	Sylmar AC	2.05	2.05			
Montana intertie		3.56	LADWP	9.00	9.00			
BC Hydro		3.98						
Alberta (includes losses)	3.00	3.00						

Notes:

With RTO West case: RTO West tariff is $3.60, plus a $0.20 administrative charge.

BPA charge applies to wheel-outs and wheel-ins. When wheeling power over an intertie, the intertie rate is added to the network rate.

California and WestConnect charges apply to wheel-outs, except for Imperial Irrigation, which applies to wheel-ins and wheel-outs.

No charges apply to flows within the California ISO (PG&E, SCE, and SDG&E) for both scenarios.

3.3.5 Modeling of Charges for Losses

In the Energy Impact Analysis, charges for losses were added to the transmission tariff rates and were applied to power flowing out of a region or control area (wheel-outs and wheel-throughs). As with the treatment of a wheeling charge, a loss charge[22] was applied only to power flowing out of an RTO in the With RTO case; transactions within an RTO were not charged for losses. In the With RTO case, RTO West was separated into two sub-regions, BC Hydro and the rest of RTO West, applying respectively BC Hydro's loss rate or using a load-weighted average loss factor of individual companies for the balance of RTO West. The tariff losses were applied to flows between the two sub-regions and flows to external regions.

Note that since GE MAPS does not calculate marginal loss factors on an hourly basis and thus cannot determine the actual losses on the system, TCA modeled the transmission losses on the DC lines only. GE MAPS uses a set of fixed loss factors based on the specified load flow case and scales these factors up or down as the load increases or decreases with respect to the base case (i.e., it assumes a linear relationship between transmission losses and load on the system). As long as the power flows on transmission lines do not change direction, this is a reasonable approximation, but as is well known in

[21] However, the higher single export rate in the With RTO case counter balances the reduced pancaking levied in the Without RTO West case.

[22] The losses charge was calculated using a loss factor and an average energy price around $30/MWh.

the west, the flows reverse direction depending on the season. As a result, the GE MAPS logic to calculate marginal losses was not used, and the impact on market clearing prices of changing physical losses was not determined. Rather, only financial fees for losses, and the resulting impact on the dispatch and market clearing prices of eliminating the pancaking of these fees, were incorporated into the Energy Impact Analysis. In the Without RTO West case, tariff loss rates were charged at the boundaries of control areas using loss factors by company. Both the With and Without loss factors are shown in Table 2.

The Energy Impact Analysis also treated loads as if they were located at the generation bus, thus capturing the cost of transmission losses, but not any impacts of distribution losses.[23]

Table 2: Loss Rates With and Without the RTO

Loss Factors

Region / Utility	*With RTO*	*Without RTO*	*Region / Utility*	*With RTO*	*Without RTO*	*Region / Utility*	*With RTO*	*Without RTO*
RTO West	2.83%	0%	California			WestConnect		
Avista Corp.		3.00%	PG&E - high voltage only			Arizona Public Service		2.50%
Idaho Power Company		3.60%	PG&E - low voltage			El Paso Electric		3.00%
Montana Power Co.		4.00%	SCE - high voltage only			Public Service of New Mexico		3.00%
PacifiCorp		4.48%	SCE - low voltage			Salt River Project		2.30%
Portland General Electric		1.60%	SDG&E - high voltage only			Texas-New Mexico Power	included in wheeling charge	3.34%
Puget Sound Energy		2.70%	SDG&E - low voltage			Tucson Electric Power		3.30%
Sierra Pacific Resources	0.00%		California - Oregon Border (COB)	3.0%	3.0%	WAPA Lower Colorado		3.00%
Zone A (Sierra Pacific Power)		2.34%	Palo Verde intertie			WAPA Rocky Mountain		5.50%
Zone B (Nevada Power)		1.32%	Nevada - Oregon Border (NOB)			WAPA Upper Missouri		4.00%
Bonneville Power Administration			Mead intertie (MEAD - WALC)			Imperial Irrigation District		3.0%
Network		1.90%	Victorville intertie					
Southern intertie		3.00%	Sylmar AC					
Montana intertie		3.00%	LADWP	4.8%	4.8%			
BC Hydro	6.05%	6.05%						
Alberta (included in wheeling charge)	-	-						

Notes:

BPA loss factor applies to wheel-outs and wheel-ins. When wheeling power over an intertie, the intertie rate is added to the network rate.
California and WestConnect losses apply to wheel-outs, except for Imperial Irrigation, which applies to wheel-ins and wheel-outs.
No charges apply to flows within the California ISO (PG&E, SCE, and SDG&E) for both scenarios.
No charges apply to flows within Westconnect for With RTO West scenario.

3.3.6 Contract Path Limits

TCA used contract path power flows limits from a study done for the Western Governors' Association[24] for the Without RTO case only. Wheeling charges and losses along these paths were calculated as previously described. If more than one tariff existed along a contract path, a simple average of the tariffs along that path was used.

[23] This is generally seen as reasonable, as the implementation of an RTO in and of itself would likely not significantly affect the distribution company charges.
[24] "Conceptual Plans for Electricity Transmission in the West, Report to the Western Governors' Association," August 2001. Available on the website: www.westgov.org.

RTO West and WSCC provided the contract path scheduling limit data, and the limits are listed in Attachment 1.

No contract path flows were used in the With RTO case; only real power flows and physical constraints were used.

3.3.7 Operating Reserves

The operating reserves are set by WSCC as a percentage of load in each control area. TCA modeled the operating reserve requirement as 7% of the load in each control area, of which 50% was spinning reserve and 50% was non-spinning reserve. The spinning reserve market affects the energy market prices because the units that spin cannot produce electricity under normal conditions. The energy prices are higher when reserves markets are modeled.

In the With RTO case, TCA assumed that reserve levels are 7% of each reliability region load (see three regions below) carried on most efficient units in the region, rather than 7% of individual control areas load carried on their own units. There is currently a reserve-sharing agreement among NWPP control areas; the current requirement is that each control area carries its own reserves, which is not the same as having a regional requirement.[25] This results in more economic allocation of reserves. TCA defined operating reserves for three regions (BC Hydro, Montana–Utah, and the balance of the northwest) in the With RTO scenario, based on input from the study group. These regions were used in order to capture the fact that energy from the reserves has to be deliverable to the site of the contingency, and therefore this locational requirement compensates for significant transmission constraints. Table 3 lays out the requirements in both cases.

It was assumed that only a small percentage of generation units' capacity can provide spinning reserves because there are ramp-up constraints that prevent units from delivering energy needed within short periods (usually ten minutes). This percentage varies by unit type, as listed in Attachment 1. It was assumed that a portion of unloaded hydro resources (20%) could be used to meet the spinning reserves requirements[26].

[25] There is currently a similar reserve-sharing agreement among Arizona / New Mexico / Southern Nevada control areas.

[26] Source: communication with BPA staff.

Table 3: Reserves in With and Without RTO Cases

Operating Reserves

	With RTO West	*Without RTO West*
Reserve Requirement	7% reserves 1/2 spinning, 1/2 non-spinning	7% reserves 1/2 spinning, 1/2 non-spinning
Geographic Basis	Three regions: 1. BC Hydro 2. Northwest 3. Montana-Utah	Company-by-company basis

3.3.8 Physical Transmission Constraints

The same data for physical transmission constraints were used for both cases, including seasonal ratings for lines in the northwest as specified by RTO West. Ratings from the WSCC 2001 Path Rating Catalog were used for other areas. TCA included all proposed transmission projects expected to come on-line by 2004.

Phase angle regulators are centrally controlled and optimized to minimize total production cost in both cases, but they effectively minimize loop flow in the Without RTO case, and attempt to hold power flows according to the schedules. RTO West provided the load flow data, based on the list of transmission upgrades and data contained in the Western Governors' Association (WGA) study, as well as the seasonal path ratings. All of these are listed in Attachment 1.

3.3.9 Maintenance Schedule for Generation Units

The GE MAPS feature of scheduling maintenance of thermal generation units was used to levelize the reserves on an annual basis (reserves being available capacity minus peak load on a weekly basis).

In the Without RTO case, it was assumed that companies schedule the maintenance of their units such that they levelize their own reserves on an annual basis. For example, if a company's load peaks in the summer, it will schedule little or no maintenance in that season; similarly, if a company's load peaks in the summer and winter, it will schedule no maintenance in these two seasons. For the With RTO case, it was assumed that the RTO will coordinate the scheduling of generation unit maintenance across all units in the RTO region, and that the maintenance schedule will be determined by levelizing the reserves for the entire region on an annual basis. This effectively means a better and more economic scheduling of maintenance on generation units.

Note that the RTO-coordinated maintenance schedule could yield company-specific schedules that are more expensive to a few individual entities and yet are more efficient on a system-wide basis. This is therefore an issue to consider, and more importantly it is something that cannot be achieved without coordination by an RTO or a similar institution.

3.3.10 Generation from Hydro Units

The hourly generation schedule of hydro units in the northwest and British Columbia was provided by RTO West based on average hydro conditions and was used in the GE MAPS in both With RTO and Without RTO cases. The Benefit Cost Work Group decided on this approach to ensure that the model captured all environmental, operational, and other constraints that determine generation from hydro units. The work group fixed the hydro schedule because the "hydro operations in the Pacific Northwest are driven largely by non-power constraints associated with fish and wildlife mitigation, flood control, irrigation, navigation, etc." [27]

The hydro generators in California (including pump storage units) are scheduled against California ISO load in both With RTO and Without RTO cases. Only hydro generation in the southwest and small hydro units in the northwest and Canada are scheduled differently in the With RTO and Without RTO cases; in the Without RTO case, these units are scheduled against a company's load, while in the With RTO case they are scheduled against regional load, i.e., the RTO load in which these units are located.

The GE MAPS model generally does not dispatch hydro generation to relieve transmission congestion. However, if the locational price at the generation unit is very low (less than $5/MWh), then MAPS backs down generation from that unit to relieve congestion; that is, backing down the hydro unit is the most economic and maybe the only alternative to relieving congestion. Also, GE MAPS does not increase generation from hydro resources to relieve congestion. This modeling assumption impacts the results in both cases because thermal units are used for congestion management in both cases. It is not clear how modeling fixed hydro schedules biases the results compared to reality. Also, to the extent that the operational and environmental constraints prevent dispatching hydro to relieve transmission congestion, the model is replicating reality.

Overall, TCA believes that this assumption produces a conservative representation of benefits, because the hydro generation is not flexible enough to take advantage of the changes in market conditions due to the implementation of RTO West. Thus there could be additional benefits from more optimal scheduling of hydro resources, which are not captured in this quantitative analysis.

[27] Communication with Carol Opatrny.

3.3.11 Regional Least-Cost Dispatch

The GE MAPS feature of committing generation resources on regional basis (equivalent of the day-ahead market) and dispatching generation units on the WSCC-wide basis was used in both the With RTO and Without RTO cases. The objective was to capture all the economy transactions that currently take place among various entities in the WSCC, even without an RTO, and those expected by establishing RTO West. This modeling assumption represents an assumption that the wholesale electricity market in the WSCC is currently very efficient and that RTO West will not increase the efficiency of the trading market. This is a conservative assumption that does not capture the increased efficiency of the WSCC market that would arise (if any) from implementing RTO West.

3.4 Summary of Results - Base Cases

The results of the GE MAPS analysis are summarized in this section. The section provides the quantification of benefits, changes in energy prices, and resulting transmission constraints for the base case and sensitivity analyses. All financial values shown in this section are expressed in real year-2000 dollars. All dollar values in this and other report sections are in U.S. dollars unless otherwise stated.

The quantification of benefits from the GE MAPS analysis is based on comparisons between the two scenarios[28] and includes generation production cost, load payments based on spot market purchases, and generation revenues based on spot market payments. The comparisons are made both across the WSCC system and, where possible, for the RTO West region.

Results are presented for both the changes in the value of energy to loads[29] and the generators' revenues (based on the value of energy at the generator busses).

As reported, both the load costs and the generator revenues consist of several components: energy, daily uplift, spinning reserves, and other factors not modeled (Installed Capacity, Automatic Generation Control and other ancillary services). The energy revenue or payment is the marginal value of energy at each load bus times the

[28] Capturing benefits in this way removes the majority of concerns regarding inaccuracies in modeling variables, as the great majority of parameters act equally in both the With and Without RTO cases. By examining differences between the cases, therefore, adverse impacts of a majority of modeling assumption inaccuracies are eliminated.

[29] As was earlier stated, the Energy Impact Analysis calculates the marginal price of energy. For calculating benefits, the value of the energy consumed by the loads is calculated as the marginal price of energy at each load bus times the load consumption at that bus. These are the values that are compared between the With and Without RTO cases. Throughout this analysis, other, more concise terms are used to represent this value. As such, it should not be assumed that when terms such as "Load Energy Payment", or "costs to loads", are used TCA was presumptuous enough to know what loads would actually pay. What loads actually will pay depends on many factors, including rate design, which are outside the scope of this wholesale analysis. The analysis herein is limited to the value of the marginal value of the wholesale energy.

volume of energy delivered or consumed. Daily uplift is an accounting of funds needed to "make generators whole" across each operating day, should the most economic solution dispatch a generator that subsequently does not recover its startup costs through energy net revenues.

Uplift is a construct in use in most of the location-based marginal-priced markets in the East. Spinning reserves represent the sum of funds paid to resources for provision of spinning reserves or charged to loads for their having received the spinning reserve service. It is useful to keep in mind that when benefits are netted across load and generation sectors, the changes in daily uplift and spinning reserve payments net out because those two categories of funds are equally paid and received by loads and generators respectively.

3.4.1 Summary of Benefits - Base Cases

This section presents the Energy Impact Analysis results for the fundamental cases modeled as the "base cases."[30]

Table 4 presents the results of the base case analysis. The figures in the table, as with all similar results tables in this section, represent the difference of the modeling results in the With RTO and the Without RTO cases. Columns A and F show that energy prices go down, causing load payments and generators' revenues to go down, in the With RTO case compared to the Without RTO case. Column C shows that the spinning reserve market prices also go down, lowering both load payments and generators revenues; having a similar impact as energy prices. Since load and generation see the same spinning reserve savings, this has no net impact. However, spinning reserves have an indirect net impact through the energy prices, as is to be seen in the sensitivities in the next section.

Note that RTO West production costs increase simply because exports increase as pancaked wheeling charges are eliminated.

[30] The results here differ from the preliminary results presented on February 4, 2002 in two ways: first, the wheeling charges for BC Hydro, Montana Power Company, Nevada and Sierra Power were modified. Second, the cost and revenues from purchases and sales from outside the WSCC were included.

Table 4: Summary of Benefits, Base Cases

Summary of Benefits ($M)- Difference Between With and Without RTO - Base Case								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(53)	0	(1)	(54)	(8)	(51)	(44)	10
BRITCOL	(70)	(2)	(3)	(75)	(87)	(147)	(65)	10
CA ISO	(526)	13	(50)	(563)	(174)	(711)	(573)	(10)
Rocky Mtn	(266)	0	(77)	(343)	(58)	(253)	(272)	70
Rest of RTO West	(1,174)	1	(209)	(1,383)	124	(755)	(1,087)	295
W Connect	(426)	(1)	(111)	(539)	(37)	(429)	(504)	34
Total	(2,516)	11	(451)	(2,956)	(239)	(2,345)	(2,546)	410

The table shows WSCC-wide savings of $410 million; $239 million are due to generation cost savings due to more efficient dispatch, while the remaining $171 million are from lower transmission rents due to lower transmission congestion causing lower congestion charges.

In these base cases, the 2004 annual marginal cost to serve load under the locational pricing structure proposed for RTO West and modeled in the TCA analysis decreases in the northwest by $1.3 billion[31] as a result of implementing RTO West and WestConnect. At the same time, the lower prices result in lower generator net revenues of approximately $1.1 billion. The difference between the loads' cost reduction and the generators' net revenue reduction represents the net societal benefit of $305 million for the RTO West region and $410 million for all of the WSCC.

3.4.2 Explanation of Benefits

The Energy Impact Analysis further provides insights as to the nature of the overall system cost reductions. For the WSCC,[32] of the $410 million difference between the decreased cost of energy to serve load and the decreased generator net revenues, approximately half ($239 million) represents savings in production costs, predominantly arising from greater efficiency in operations that reduce fuel costs.

The balance of the $410 million in WSCC, approximately half, represents the calculated value of decreased congestion rents, which consist of transmission congestion, transmission wheeling and loss charges. In a locational, marginal-priced energy system

[31] For RTO West impacts the totals from the "RTO West W/O BC" and the "Britcol", otherwise broken out for further information, are added.

[32] The WSCC is used here as an example. The analysis modeled the entire WSCC, but across the WSCC generation and consumption is balanced in both cases. Within the Northwest region, the model shows that the exports increase out of the northwest in the With RTO case, making quantification of the exact attribution of the benefits impossible. The sensitivity cases help to identify the component drivers of the benefits. These are presented in detail in the body of the report.

(as is envisioned for RTO West), the value[33] of reduced transmission congestion[34] is greater than the value of the reduction in production costs. The same phenomenon is also seen in the RTO West region. TCA's analysis shows the significance of the congestion costs in the WSCC. If users were required to pay for the marginal cost of congestion rather than only average or incremental cost, as is the case at present, the costs they incurred would be $171 million less with the RTO than without.[35]

In addition to these benefits described across the WSCC, specific benefits accrue to the northwest, as the northwest generators are seen as more competitive in the With RTO case and export more energy out of the northwest. This explains why generators' operating costs in the northwest increase with the RTO; although more efficient generators are running to meet the needs of the northwest, the northwest generators are exporting significantly more energy out of the northwest in the With RTO case than in the Without RTO case. The table demonstrates that within the WSCC the great majority of benefits from RTO West accrue to the northwest, rather than to neighboring regions.

Finally, in the analysis hydro generation in the northwest consists of a pre-defined schedule so as to ensure that the MAPS dispatch mechanism does not violate environmental limits. This results in some unrealistic system behavior. For example, to the extent that hydro generation has flexibility to vary output from hour to hour, one would expect the hydro operators to change operating behavior to reflect the new market conditions and capitalize on high-priced hours. To the extent that this can occur, actual benefits will be higher than simulated benefits.

3.4.3 Change in Generation Patterns

Table 5 shows the levels of generation in the With RTO and Without RTO cases for each region. This table also demonstrates that the total generation on the system equals the

[33] In such a system, the "value" of the congestion is deemed to be equal to the product of (1) the value of a constrained path and (2) the flow of energy across the path.

[34] To understand the source of the system congestion savings beyond the fuel cost savings, consider the following example. Assume that loads and generators are attempting to use a 1000MW transmission path. If 1001MW of flow requests use of the path, congestion is created and 1MW of redispatch is required to maintain the path within limits. Assume it costs $10 in redispatch cost to alleviate the 1 MW because the fuel cost to alleviate the constraint was $10. In a locational marginal-price system the value of the congestion would be $10 X 1001 MW of users on the path, or $10,010. This is the marginal value of the path. Assume an RTO is implemented in this simple example, and a more efficient generator is able to alleviate the 1 MW of congestion, resulting in a redispatch cost of only $9. In this case the marginal value of the constrained path is $9,009. Applying the concepts of the Energy Impact Analysis to this example would say that the operating cost savings was $1, but reduction in the value of congestion was roughly $1000; loads and generators would have paid $1000 less to use the path in the With RTO case.

[35] If the marginal value of congestion were valued explicitly today, the great majority of the congestion costs would be borne by the Transmission Owners (TOs). Moving to the RTO structure in this framework would result in a transfer of $171 million cost away from the TOs (or possibly transmission rights holders in an RTO framework) and to the loads and generators in the With RTO case.

total load including the pump storage load. It is important to make sure that the energy balance is met, and if the same market clearing prices were used for all buses then there would be no transmission rent or difference in transmission rent.

Table 5: Generation Output in Base Cases

Generation and Demand Balance - Base Cases					
	Generation (GWh)			Demand (GWh)	
Sub-Region	Without	With	Demand	PS Demand Without	PS Demand With
ALBERTA	57557	57362	57278		
BRITCOL	58452	55996	63478		
CA ISO	290232	285498	297923	3,789	3,764
Rocky Mtn	41870	39841	55203		
RTO West	278519	286672	281203		
W Connect	136837	137786	103659	923	635
Total	863467	863154	858744	4,722	4,410
Net after PS	858745	858744			

Table 6 shows the impacts of implementing the RTO on the mix of generation output, as determined in the Energy Impact Analysis. There is a net increase in generation in the RTO West region, mainly from low-cost units, such as coal units, which displace more expensive units (such as combustion turbines and steam gas) in California, the Southwest, and British Columbia. Note the lower generation in British Columbia, which means higher imports from the northwest and Alberta, and lower production cost since the expensive steam gas fired units are displaced.

Note that there is a net mismatch in generation of 313 GWh, which is due to change in the pumping load of pump storage units.

Table 6: Impact of RTO on Generation Mix

Difference in Generation by Unit Type: With RTO-Without RTO (GWh)								
Unit		Region						
Type	Legend	Alberta	BC Hydro	CA ISO	Rocky Mtn	RTO-W	W Connect	Total
AS	Aluminium Smelter Interruptible Loads	0	1	0	0	(28)	0	(27)
CCg	Combined Cycle Gas	20	0	(956)	(1053)	2638	2505	3154
CCgo	Combined Cycle Gas/Oil	0	0	18	0	165	27	210
CCog	Combined Cycle Oil/Gas	0	0	0	0	0	8	8
CG	Co-Generation	2	91	0	114	0	1	209
CTg	Combustion Turbine Gas	(48)	(293)	(978)	(902)	227	(464)	(2457)
CTgo	Combustion Turbine Gas/Oil	0	0	(64)	33	270	0	239
CTo	Combustion Turbine Oil	0	0	0	0	0	0	0
DD	Dispatchable Demand	0	0	(1)	(0)	(1)	(0)	(1)
GEO	Geothermal	0	0	5	0	5	0	10
GTg	Turbine Gas	(6)	0	(272)	10	(30)	0	(298)
GTgk	Turbine Gas/Kerosene	0	0	0	0	0	0	0
GTgo	Turbine Gas/Oil	0	0	0	0	180	0	180
GTk	Turbine Kerosene	0	0	0	0	0	0	0
GTo	Turbine Oil	0	0	0	0	(3)	0	(3)
GTog	Turbine Oil/Gas	0	0	0	0	0	0	0
HRM	Hourly Modifier: Hydro or DC Export	0	0	0	0	(11)	0	(11)
ICgo	Internal Combustion Engine Gas/Oil	0	0	0	0	(0)	0	(0)
ICo	Internal Combustion Engine Oil	0	0	0	0	(0)	0	(0)
NU	Nuclear	0	0	0	0	0	0	0
OTn	Other Types - Non-specified Fuel	1	0	(0)	0	900	0	901
PND	Pondage or Conventional Hydro	0	(0)	(0)	0	0	0	(0)
PSH	Pumped Storage	0	0	(18)	(13)	0	(187)	(217)
PUR	Purchase: DC Import	(162)	0	0	(317)	0	(1445)	(1923)
RET	Retired Unit	0	0	0	0	0	0	0
SOL	Solar	0	0	0	0	0	0	0
STc	Steam Turbine Coal	(3)	0	215	181	3948	746	5086
STcg	Steam Turbine Coal/Gas	0	0	3	(85)	0	(322)	(404)
STco	Steam Turbine Coal/Oil	0	0	2	3	52	94	150
STg	Steam Turbine Gas	0	(2256)	(669)	0	(25)	0	(2950)
STgo	Steam Turbine Gas/Oil	0	0	(2019)	0	(217)	(15)	(2250)
STog	Steam Turbine Oil/Gas	0	0	0	0	0	0	0
STr	Steam Turbine Refuse	0	0	(0)	0	82	0	82
WND	Wind	0	0	0	0	0	0	0
Total		(196)	(2456)	(4734)	(2029)	8153	949	(313)

3.4.4 Average Energy Price Change with RTO West

The base case results show that average annual market clearing prices[36] go down in most load areas in the northwest with the implementation of RTO West, on the order of 10% to 15%, as shown in Table 7. Prices decrease in all regions except Montana, where removal of relatively high company wheeling rates causes an increased flow of higher-priced resources into the region.

Alberta energy prices go down, but there is minimal net impact because Alberta's connection to the WSCC is radial and Alberta is not participating in any RTO. British Columbia energy prices go down as well, but because hydro represents most of generation in BC and the hydro schedule is the same in both the With- and Without RTO cases, the benefits are not significant. Similarly, California prices go down, but the net

[36] The market clearing prices represent the marginal value of the marginal MW produced or consumed at a given location.

impact is small because there are not significant changes between the With RTO and Without RTO cases for California.

Table 7: Average Annual Energy Prices Comparison

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	35.80	34.41	(3.89)
Avista Corp	RTO-West	35.50	29.70	(16.34)
Bonneville Power Admin	RTO-West	34.82	29.75	(14.57)
Chelan Douglas Grant PUD	RTO-West	34.18	29.73	(13.01)
Idaho Power Company	RTO-West	30.30	28.93	(4.53)
Montana Power Company	RTO-West	25.24	26.82	6.27
Nevada Power Company	RTO-West	33.75	30.38	(9.99)
Pacificorp East	RTO-West	30.16	27.46	(8.94)
Pacificorp West	RTO-West	32.73	29.68	(9.33)
Portland General Electric	RTO-West	33.42	29.73	(11.05)
Puget Sound Energy	RTO-West	35.60	29.77	(16.39)
Seattle City Light	RTO-West	34.82	29.75	(14.56)
Sierra Pacific Power	RTO-West	40.99	33.21	(18.97)
Tacoma Public Utilities	RTO-West	34.42	29.75	(13.56)
Alberta Power	ALBERTA	23.98	23.81	(0.69)
LA Dept of Water & Power	CA ISO	34.39	30.99	(9.87)
Pacific Gas & Electric	CA ISO	32.88	31.32	(4.76)
San Diego Gas & Electric	CA ISO	32.20	30.97	(3.83)
Southern California Edison	CA ISO	32.93	31.41	(4.61)
Public Service of Colora	Rocky Mtn	32.66	25.72	(21.23)
WAPA Colorado-Missouri	Rocky Mtn	26.75	25.76	(3.73)
WAPA Upper Missouri	Rocky Mtn	27.59	24.56	(10.99)
Arizona Public Service	WConnect	31.17	27.77	(10.93)
El Paso Electric	WConnect	36.17	30.63	(15.32)
Imperial Irrigation Dist	WConnect	30.69	28.71	(6.44)
Public Service New Mexico	WConnect	33.16	27.80	(16.14)
Salt River Project	WConnect	31.12	27.68	(11.06)
Tucson Electric Power	WConnect	31.14	27.41	(11.96)
WAPA Lower Colorado	WConnect	31.11	27.42	(11.85)

3.4.5 Monthly Energy Price With RTO

Table 8 shows the average monthly prices in each region in the With RTO case. These prices are the simple average of hourly load-weighted zonal prices over each month. The energy prices vary by location and time, and prices are higher in constrained areas during their load peak periods (such as British Columbia in the winter, and SDG&E in the summer).

Table 8: Monthly Energy Prices With RTO

Monthly Simple Average of Hourly Load-Weighted Average Energy Prices ($/MWh)														
Area	Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Alberta Power	Alberta	31	25	22	21	24	22	22	18	20	24	24	23	23
BC Hydro + W Kooteny	BC Hydro	53	37	33	29	33	31	31	25	30	37	38	37	35
LA Dept of Water & Power	CA ISO	30	32	30	27	28	30	33	31	31	33	34	33	31
Pacific Gas & Electric	CA ISO	30	32	30	28	29	30	34	31	32	34	34	33	31
San Diego Gas & Electric	CA ISO	30	32	30	28	28	30	33	31	31	33	33	32	31
Southern California Edis	CA ISO	31	32	30	30	30	30	33	31	31	33	33	33	31
Public Service of Colora	Rocky Mtn	26	26	25	23	23	25	27	25	25	28	30	28	26
WAPA Colorado-Missouri	Rocky Mtn	26	27	25	23	23	25	27	25	25	28	30	28	26
WAPA Upper Missouri	Rocky Mtn	26	26	25	22	21	18	24	23	23	27	31	30	25
Avista Corp	RTO W	31	31	29	24	24	24	30	27	28	36	37	35	30
Bonneville Power Adminis	RTO W	31	31	29	24	24	25	30	27	28	36	37	35	30
Chelan Douglas Grant PUD	RTO W	31	31	29	24	24	25	30	27	28	36	37	34	30
Idaho Power Company	RTO W	29	30	28	24	25	27	30	27	27	32	35	33	29
Montana Power Company	RTO W	27	28	26	24	24	20	27	25	26	29	33	32	27
Nevada Power Company	RTO W	29	31	29	27	28	31	34	30	31	32	32	30	30
Pacificorp East	RTO W	27	29	27	24	25	27	28	26	26	29	31	29	27
Pacificorp West	RTO W	31	31	28	24	24	25	30	27	28	36	37	34	30
Portland General Electri	RTO W	31	31	29	24	24	25	30	27	28	36	37	34	30
Puget Sound Energy	RTO W	31	31	29	24	25	25	30	27	28	36	37	35	30
Seattle City Light	RTO W	31	31	29	24	25	25	30	27	28	36	37	34	30
Sierra Pacific Power	RTO W	36	33	30	26	28	30	35	31	33	38	39	38	33
Tacoma Public Utilities	RTO W	31	31	29	24	25	25	30	27	28	36	37	35	30
Arizona Public Service C	W Connect	27	29	27	24	25	27	30	27	28	30	30	28	28
El Paso Electric	W Connect	32	29	27	25	29	33	34	31	31	31	32	33	31
Imperial Irrigation Dist	W Connect	28	29	27	25	27	28	32	29	29	30	31	29	29
Public Service New Mexic	W Connect	27	28	27	24	25	28	30	27	28	29	30	29	28
Salt River Project	W Connect	27	29	27	24	25	27	30	27	28	30	30	28	28
Tucson Electric Power	W Connect	26	29	27	24	25	27	30	27	28	29	30	28	27
WAPA Lower Colorado	W Connect	27	28	27	24	25	27	30	27	28	29	30	28	27

Table 9 shows the load-weighted average monthly prices in each region in the With RTO case. These prices are the zonal load-weighted average of hourly load-weighted zonal prices over each month. These prices would be more reflective of energy cost when multiplied by the monthly energy consumption of each region. The pattern is similar to that in the preceding table.

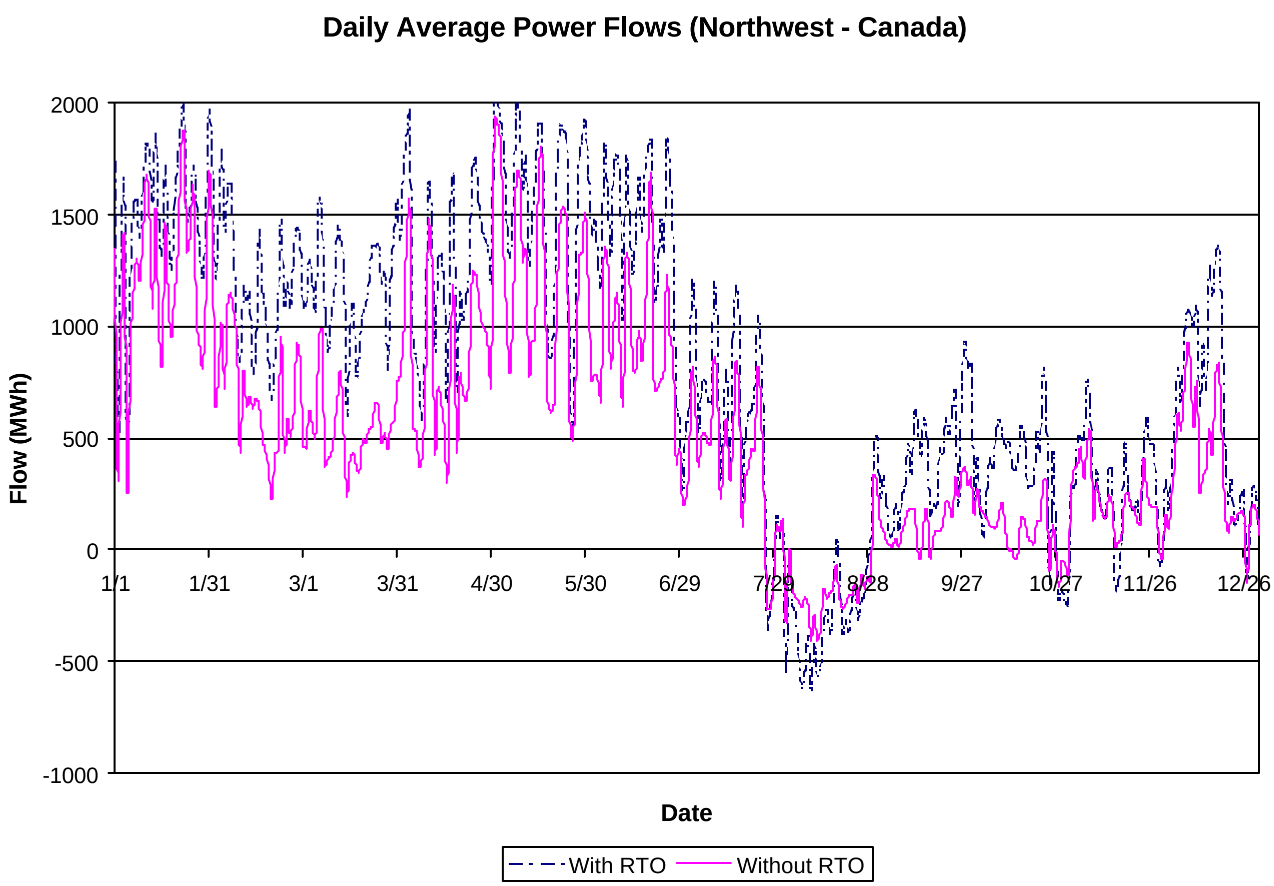
Table 9: Monthly Load-Weighted Average Energy Prices—With RTO

Monthly Load-Weighted Average of Hourly Load-Weighted Average Energy Prices ($/MWh)														
Area	Region	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Year**
Alberta Power	Alberta	32	26	22	22	24	23	22	19	20	24	25	24	24
BC Hydro + W Kooteny	BC Hydro	56	37	33	29	34	31	32	26	30	38	39	37	36
LA Dept of Water & Power	CA ISO	30	32	30	28	29	31	34	31	32	33	34	33	32
Pacific Gas & Electric	CA ISO	30	33	30	28	30	31	35	32	33	34	35	34	32
San Diego Gas & Electric	CA ISO	30	33	30	28	29	31	35	32	32	34	34	33	32
Southern California Edis	CA ISO	31	32	30	30	30	31	35	32	32	34	34	33	32
Public Service of Colora	Rocky Mtn	26	27	25	23	24	26	28	26	26	28	30	29	26
WAPA Colorado-Missouri	Rocky Mtn	26	27	25	23	23	25	28	25	25	28	30	29	26
WAPA Upper Missouri	Rocky Mtn	26	26	25	22	22	19	25	24	24	28	31	31	25
Avista Corp	RTO W	31	31	29	24	24	24	30	27	29	37	37	35	30
Bonneville Power Adminis	RTO W	31	31	29	24	25	25	30	27	29	37	37	35	30
Chelan Douglas Grant PUD	RTO W	31	31	29	24	25	25	30	27	29	36	37	35	30
Idaho Power Company	RTO W	29	30	28	25	25	27	30	27	28	33	35	33	29
Montana Power Company	RTO W	27	28	27	24	24	20	28	26	26	30	33	32	27
Nevada Power Company	RTO W	29	31	29	27	29	32	36	32	32	33	33	30	31
Pacificorp East	RTO W	27	29	28	25	26	28	29	27	27	30	32	30	28
Pacificorp West	RTO W	31	31	29	25	25	25	31	28	29	36	37	35	30
Portland General Electri	RTO W	31	31	29	25	25	25	31	27	29	37	37	35	30
Puget Sound Energy	RTO W	31	31	29	25	25	25	30	27	29	37	37	35	30
Seattle City Light	RTO W	31	31	29	25	25	25	30	27	29	37	37	35	30
Sierra Pacific Power	RTO W	36	33	30	26	28	30	35	31	34	38	39	38	33
Tacoma Public Utilities	RTO W	31	31	29	24	25	25	30	27	29	37	37	35	30
Arizona Public Service C	W Connect	27	29	27	25	26	28	31	28	29	30	30	29	28
El Paso Electric	W Connect	32	29	27	25	29	33	34	31	31	31	32	33	31
Imperial Irrigation Dist	W Connect	28	29	27	26	27	29	32	29	30	31	31	30	29
Public Service New Mexic	W Connect	27	28	27	24	26	28	30	28	28	30	30	29	28
Salt River Project	W Connect	27	29	27	25	26	28	31	28	29	30	30	29	28
Tucson Electric Power	W Connect	26	29	27	25	26	28	31	28	29	30	30	29	28
WAPA Lower Colorado	W Connect	27	30	28	26	27	30	33	29	30	31	32	30	29

3.4.6 Comparing With RTO and Without RTO Power Flows

Figure 2 shows the hourly flows from the U.S. to Canada (positive) starting in January, in the With RTO and Without RTO West cases. The figure demonstrates how the economic transfers (power flows) increase among regions with the introduction of RTO West.

Figure 2: Intertie Flows With and Without the RTO



3.4.7 Binding Transmission Constraints

The more efficient dispatch causes higher congestion on some paths and lower congestion on other paths (because it is utilizing the transmission system more efficiently without the contractual constraints). Table 10 shows the change in the number of hours in which significant paths are shown by the Energy Impact Analysis to be binding.

Table 10: Impact of RTO West on Individual Constraints

	% of Hours Binding	
Constraint	**Without RTO**	**With RTO**
Pavant/InterMt-Gonder Actual	99%	75%
EDMONTON-CALGARY LIMIT	96%	96%
Eagle Mountain-Blythe 161 k	90%	91%
Montana to Northwest MIN	74%	75%
Northwest-Canada MIN	46%	67%
Pacificorp/PG&E South	63%	7%
TOT 2C	58%	44%
PG&E - SPP	58%	15%
NM1 Actual	15%	50%
Montana Southeast Tie MIN	35%	48%
ALTURAS	22%	40%
Idaho to Northwest MIN	26%	30%
Intermountain - Mona 345	26%	26%
South of San Onofre	16%	9%
Montana to Northwest MEAN	11%	15%
Inyo-Control 115 kV	13%	15%
Idaho-Sierra	5%	11%
BLGS PHA 230-YELOWTLP 230	8%	10%
INYOKERN-KRAMER 115	10%	10%
Billings-Yellowtail	9%	7%
Northwest-Canada	3%	9%
BIGGRASS 161-DILLON S 161	4%	8%
Northern - Southern Californ	7%	8%
Coranado-Silverking-Kyrene	1%	7%
COI MIN	6%	4%
TOT 2A Actual	0%	5%
Montana Southeast Tie	0%	5%
BOUNDARY 230-NLYPHS 230- 1	2%	5%
Path C Actual MIN	2%	4%
Midway - Los Banos	4%	2%
WOR Northern System Actual	1%	4%
Northwest-Canada MEAN	0%	2%
TOT 1A Actual	2%	1%
TOT 4B Actual	2%	2%
Keeler Allston Tie MIN	1%	1%
MONA 345-BONANZA 345- 1	0%	1%
LUGO 500-VICTORVL	1%	1%
Borah West Actual	0%	1%
TOT 5 Actual	0%	1%
HATWAI 230-LOLO 230 0	1%	1%
Bridger West	0%	1%
Idaho-Northwest 500	0%	1%
West of Borah - Path 15 Wint	1%	0%
TOT 3 Actual	0%	0%

3.5 Sensitivity Runs - Descriptions and Results

TCA was directed to evaluate sensitivity runs of two types:

1. Physical System Modifications
    a. Short Supply Case: Low Water/High Gas Prices
    b. Resource Addition Case: Montana New Entry

2. Benefits Driver Sensitivities
    a. With RTO: Transmission Line Losses Fixed as Without RTO
    b. With RTO: RTO Export Fees Set to Zero
    c. With RTO: Scheduling Limits Fixed as Without RTO
    d. With RTO: Maintenance Schedule Fixed as Without RTO
    e. Operating Reserves (Non AGC) set to zero in both cases, eliminating impact of Operating Reserves on Benefits

3.5.1 Summary of Sensitivity Runs

The sensitivity analyses suggest two primary benefit drivers, which reflect the modeling techniques. The pancaked rates seem to have a strong bearing on benefits; by reinstating pancaked loss charges alone, net benefits dropped by 38% (to $255 million), all of this reduction ($155) comes from reduced congestion rent savings. This sensitivity case was the only case significantly impacting congestion rent savings. Similarly, operating reserves seem to be the only attribute tested that a strong effect on production cost benefits. The efficient allocation of operating reserves also has a strong bearing on total benefits: isolating the impact of operating reserves showed over 60% reduction in production cost savings (from $239 million to $89 million).

The Energy Impact Analysis is relatively insensitive (3% or less impact on total benefits) to other tested attributes, including maintenance scheduling, contract path scheduling limits, and export fees.

From the sensitivity runs, TCA draws the following broad implications:

- Pancaking therefore has a greater impact on the congestion prices across constraints than it does on overall production cost efficiency; and
- The ability to further substitute hydro resources for thermal resources , through further regionalization of operating reserves, offers significant benefits.

Table 11 summarizes the impact of various benefit-driver sensitivities.

Table 11: Summary of Sensitivity Run Results

Savings in $ Millions (2000 Dollars)			
Sensitivity	Impact on Generation Cost Savings	Impact on Congestion Rent Savings	Total Impact
Base Case	239	171	410
Use Low Hydro conditions and High Gas prices in both cases	263	142	405
Change in Savings	24	-29	-5
Use higher New Entry in Montana in both cases	246	150	396
Change in Savings	7	-21	-14
Pancaked Loss Charges in With RTO West Case	241	14	255
Change in Savings	2	-157	-155
Set the export fee to zero in the With RTO Case	239	164	403
Change in Savings	0	-7	-7
Impose Scheduling Limits on Paths in with RTO West Case	238	160	398
Change in Savings	-1	-11	-12
Use same Maint. Sch. for Gen. units in both cases	212	196	408
Change in Savings	-27	25	-2
Isolate the impact of Operating Reserves in both cases	89	202	291
Change in Savings	-150	31	-119

3.5.2 Low Water/High Gas Prices

In this sensitivity, the following were changed in the With RTO and Without RTO cases:

- The hydro fixed schedule was changed to correspond to a dry hydro year as provided by RTO West.
- Natural Gas price forecast was changed to correspond to EIA high gas price forecast (AEO 2001).

Summary of Benefits

The results summarized in Table 12 show that net benefits would decrease by $5 million, due to greater fuel savings of $24 million and reduced transmission rent savings of $29 million compared to the base case as shown in Table 11[37].

Table 12: Low Water/High Gas Price Results

Summary of Benefits ($M)- Difference Between With and Without RTO - Low Water/High Gas								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(59)	0	0	(58)	(4)	(50)	(46)	13
BRITCOL	(93)	(2)	(16)	(111)	(84)	(171)	(106)	5
CA ISO	(1,044)	22	(120)	(1,142)	(108)	(1,170)	(1,159)	(17)
Rocky Mtn	(471)	(2)	(107)	(580)	(139)	(444)	(413)	167
Rest of RTO West	(943)	3	(340)	(1,280)	102	(641)	(1,081)	199
W Connect	(591)	(3)	(132)	(726)	(30)	(583)	(688)	38
Total	(3,201)	18	(714)	(3,898)	(263)	(3,060)	(3,493)	405

3.5.3 Montana New Entry

The following generation units were added in Montana in both With RTO and Without RTO cases (on-line date is 2002–2003):

- MT First MW: 280 MW gas-fired combined cycle unit at Great Falls
- Hardin Generator: 100 MW coal-fired steam unit at Hardin Auto
- MT Wind harness—3 sites
- 50 MW, near Judith Gap
- 50 MW, near Cut Bank
- 50 MW, near Adel-Seiben

Summary of Benefits

The results summarized in Table 13 show that the net benefits decrease by $14 million. Although the fuel cost savings are higher by $7 million, the transmission rent savings are lower by $21 million.

[37] Additional information on annual average locational energy prices are included in Attachment 3.

Table 13: MT New Entry Results

Summary of Benefits ($M)- Difference Between With and Without RTO - MT New Entry								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(35)	0	(1)	(36)	(6)	(35)	(30)	6
BRITCOL	(40)	(2)	(1)	(44)	(91)	(119)	(32)	12
CA ISO	(479)	6	(44)	(517)	(155)	(636)	(519)	(2)
Rocky Mtn	(435)	(1)	(80)	(516)	(122)	(459)	(418)	98
Rest of RTO West	(965)	0	(196)	(1,161)	137	(570)	(902)	258
W Connect	(415)	(1)	(116)	(533)	(8)	(399)	(508)	25
Total	(2,369)	2	(438)	(2,806)	(246)	(2,218)	(2,409)	396

It is interesting that the net savings are lower in this case. As shown in Table 15, the energy prices in Montana are much lower (by 9%) than in the base case, for both the With RTO and Without RTO cases. The additional generation units created excess capacity in Montana that increased congestion out of Montana and lowered the locational energy prices in Montana, as shown in Table 14. Thus, the system is more efficient with the additional units, and there are fewer savings from implementing the RTO. This is a very important observation: the higher the excess generation levels throughout the system, the lower the savings or the benefits of establishing an RTO.

Table 14: Change in Transmission Congestion in Montana

	Base Case		MT New Entry		Change	
Line Name	With	Without	With	Without	With	Without
Montana to Northwest MEAN	1333	988	2408	1903	81%	93%
Montana to Northwest MIN	6553	6458	6973	6818	6%	6%
Montana Southeast Tie MIN	4197	3117	5519	3274	31%	5%
Billings-Yellowtail	609	794	140	582	-77%	-27%
BLGS PHA 230-YELOWTLP 230	913	690	748	668	-18%	-3%

Table 15: MT New Entry—Change in Prices

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	35.19	34.43	(2.15)
Avista Corp	RTO-West	34.57	29.42	(14.91)
Bonneville Power Admin	RTO-West	33.94	29.45	(13.22)
Chelan Douglas Grant PUD	RTO-West	33.44	29.42	(12.01)
Idaho Power Company	RTO-West	29.11	28.39	(2.48)
Montana Power Company	RTO-West	23.04	24.20	5.06
Nevada Power Company	RTO-West	32.68	30.05	(8.03)
Pacificorp East	RTO-West	28.94	26.87	(7.14)
Pacificorp West	RTO-West	31.68	29.33	(7.43)
Portland General Electric	RTO-West	31.52	29.41	(6.70)
Puget Sound Energy	RTO-West	34.77	29.48	(15.21)
Seattle City Light	RTO-West	34.01	29.46	(13.38)
Sierra Pacific Power	RTO-West	40.47	32.99	(18.50)
Tacoma Public Utilities	RTO-West	33.59	29.46	(12.30)
Alberta Power	ALBERTA	23.62	23.06	(2.40)
LA Dept of Water & Power	CA ISO	33.84	30.80	(8.99)
Pacific Gas & Electric	CA ISO	32.66	31.19	(4.49)
San Diego Gas & Electric	CA ISO	31.91	30.79	(3.49)
Southern California Edison	CA ISO	32.65	31.23	(4.33)
Public Service of Colora	Rocky Mtn	34.95	25.26	(27.73)
WAPA Colorado-Missouri	Rocky Mtn	29.13	25.19	(13.53)
WAPA Upper Missouri	Rocky Mtn	28.48	22.25	(21.89)
Arizona Public Service	WConnect	30.83	27.59	(10.49)
El Paso Electric	WConnect	36.91	30.47	(17.45)
Imperial Irrigation Dist	WConnect	30.24	28.56	(5.56)
Public Service New Mexico	WConnect	32.60	27.54	(15.53)
Salt River Project	WConnect	30.78	27.51	(10.62)
Tucson Electric Power	WConnect	30.50	27.23	(10.73)
WAPA Lower Colorado	WConnect	31.03	27.22	(12.28)

3.5.4 Transmission Line Losses

The pancaked loss charges were changed to be included in both the With and Without RTO cases, instead of the With RTO case only, as shown in Table 16.

Table 16: Pancaked Loss Factors Case—Loss Factors

Loss Factors

Region / Utility	*With & Without RTO*	*Region / Utility*	*With & Without RTO*	*Region / Utility*	*With & Without RTO*
RTO West		California		WestConnect	
Avista Corp.	3.00%	PG&E - high voltage only		Arizona Public Service	2.50%
Idaho Power Company	3.60%	PG&E - low voltage		El Paso Electric	3.00%
Montana Power Co.	4.00%	SCE - high voltage only		Public Service of New Mexico	3.00%
PacifiCorp	4.48%	SCE - low voltage		Salt River Project	2.30%
Portland General Electric	1.60%	SDG&E - high voltage only		Texas-New Mexico Power	3.34%
Puget Sound Energy	2.70%	SDG&E - low voltage		Tucson Electric Power	3.30%
Sierra Pacific Resources		California - Oregon Border (COB)	3.0%	WAPA Lower Colorado	3.00%
Zone A (Sierra Pacific Power)	2.34%	Palo Verde intertie		WAPA Rocky Mountain	5.50%
Zone B (Nevada Power)	1.32%	Nevada - Oregon Border (NOB)		WAPA Upper Missouri	4.00%
Bonneville Power Administration		Mead intertie (MEAD - WALC)		Imperial Irrigation District	3.0%
Network	1.90%	Victorville intertie			
Southern intertie	3.00%	Sylmar AC			
Montana intertie	3.00%	LADWP	4.8%		
BC Hydro	6.05%				
Alberta (included in wheeling charge)	-				

Notes:

BPA loss factor applies to wheel-outs and wheel-ins. When wheeling power over an intertie, the intertie rate is added to the network rate.

California and WestConnect losses apply to wheel-outs, except for Imperial Irrigation, which applies to wheel-ins and wheel-outs.

Summary of Benefits

The results summarized in Table 17 show that fuel cost savings increase by $2 million while transmission rent savings decrease by $157 million. Note that the increase in fuel savings is due to lower generation from thermal units.

As a result of eliminating pancaked losses in this sensitivity, the pump storage units are running less often, reducing pumped storage demand by around 13 GWh. This results in lower generation cost and the higher fuel savings.

Table 17: Pancaked Losses Results

Summary of Benefits ($M)- Difference Between With and Without RTO - Pancaked Loss Charges								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(53)	0	(2)	(54)	(8)	(53)	(46)	8
BRITCOL	(56)	(2)	(3)	(61)	(87)	(134)	(51)	9
CA ISO	(548)	15	(54)	(586)	(184)	(739)	(594)	(8)
Rocky Mtn	(251)	(0)	(76)	(327)	(62)	(250)	(264)	63
Rest of RTO West	(1,163)	1	(214)	(1,375)	121	(857)	(1,190)	185
W Connect	(344)	(2)	(106)	(452)	(20)	(365)	(454)	(2)
Total	(2,413)	14	(455)	(2,854)	(241)	(2,398)	(2,599)	255

3.5.5 Export Fees

In this sensitivity, TCA assumed that there is no export fee for energy flowing out of the RTO West region (in the With RTO case).

Summary of Benefits

The results summarized in Table 18 show that net benefits would decrease by $7 million, mainly due lower transmission rent savings. Lowering wheeling rates from $3.80/MWh to $0/MWh has small impact on system wide operation.

Table 18: Zero RTO West Export Fee Results

Summary of Benefits ($M)- Difference Between With and Without RTO - Export Fee								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(18)	0	(0)	(18)	(3)	(18)	(14)	4
BRITCOL	12	(2)	(2)	8	(83)	(68)	11	3
CA ISO	(575)	18	(54)	(611)	(196)	(778)	(618)	(6)
Rocky Mtn	(242)	0	(77)	(319)	(51)	(228)	(254)	65
Rest of RTO West	(798)	0	(201)	(998)	134	(365)	(700)	298
W Connect	(419)	(1)	(111)	(531)	(40)	(420)	(493)	39
Total	(2,041)	15	(444)	(2,471)	(239)	(1,878)	(2,068)	403

Table 19: Zero RTO Export Fee Energy Prices

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	35.80	35.87	0.20
Avista Corp	RTO-West	35.50	31.20	(12.13)
Bonneville Power Admin	RTO-West	34.82	31.27	(10.20)
Chelan Douglas Grant PUD	RTO-West	34.18	31.26	(8.52)
Idaho Power Company	RTO-West	30.30	30.25	(0.19)
Montana Power Company	RTO-West	25.24	28.06	11.18
Nevada Power Company	RTO-West	33.75	30.98	(8.23)
Pacificorp East	RTO-West	30.16	28.17	(6.61)
Pacificorp West	RTO-West	32.73	31.22	(4.61)
Portland General Electric	RTO-West	33.42	31.28	(6.42)
Puget Sound Energy	RTO-West	35.60	31.28	(12.13)
Seattle City Light	RTO-West	34.82	31.27	(10.18)
Sierra Pacific Power	RTO-West	40.99	34.47	(15.91)
Tacoma Public Utilities	RTO-West	34.42	31.27	(9.14)
Alberta Power	ALBERTA	23.98	23.72	(1.10)
LA Dept of Water & Power	CA ISO	34.39	30.97	(9.94)
Pacific Gas & Electric	CA ISO	32.88	30.99	(5.76)
San Diego Gas & Electric	CA ISO	32.20	30.96	(3.87)
Southern California Edison	CA ISO	32.93	31.37	(4.74)
Public Service of Colora	Rocky Mtn	32.66	26.14	(19.95)
WAPA Colorado-Missouri	Rocky Mtn	26.75	26.24	(1.93)
WAPA Upper Missouri	Rocky Mtn	27.59	25.63	(7.10)
Arizona Public Service	WConnect	31.17	27.85	(10.67)
El Paso Electric	WConnect	36.17	30.66	(15.23)
Imperial Irrigation Dist	WConnect	30.69	28.74	(6.34)
Public Service New Mexico	WConnect	33.16	27.86	(15.97)
Salt River Project	WConnect	31.12	27.76	(10.80)
Tucson Electric Power	WConnect	31.14	27.51	(11.63)
WAPA Lower Colorado	WConnect	31.11	27.56	(11.41)

3.5.6 Scheduling Limits

Scheduling limits were imposed on the With RTO case, but there were assumed to be no wheeling charges associated with contract path flows.

Summary of Benefits

The results summarized in Table 20 show that the contract path scheduling limits have small impact on the dispatch and prices. This happens because MAPS reschedules the flows on alternative paths at no cost (zero wheeling charges were assumed on all paths) when that path reaches its limit. The net benefits decrease by $12 million, due to lower transmission rent savings of $11 million, and lower fuel savings of $1 million.

Table 20: RTO With Scheduling Limits Results

Summary of Benefits ($M)- Difference Between With and Without RTO - Scheduling Limits								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(14)	0	(0)	(14)	(4)	(13)	(9)	5
BRITCOL	(82)	(2)	(3)	(87)	(88)	(159)	(75)	11
CA ISO	(525)	14	(50)	(560)	(175)	(712)	(572)	(12)
Rocky Mtn	(270)	0	(77)	(347)	(60)	(259)	(276)	72
Rest of RTO West	(1,164)	1	(209)	(1,372)	125	(744)	(1,078)	295
W Connect	(424)	(1)	(110)	(536)	(36)	(432)	(508)	28
Total	(2,479)	12	(450)	(2,917)	(238)	(2,319)	(2,519)	398

3.5.7 Maintenance Schedule

For this sensitivity test, instead of optimizing the maintenance schedule of generation units according to regional loads in the With RTO West case, TCA used the same maintenance schedule in the With RTO case as MAPS determined for the Without RTO case.

Summary of Benefits

The results summarized in Table 21 show a minor reduction of $2 million in net benefits for this case, resulting from additional expenditures for fuel of $27 million and reduction in transmission rents of $25 million.

Table 21: RTO With Control Area Maintenance Schedule Results

Summary of Benefits ($M)- Difference Between With and Without RTO - Maintenance Schedule								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(55)	(0)	(2)	(57)	(8)	(54)	(48)	9
BRITCOL	(70)	(1)	(3)	(75)	(75)	(130)	(59)	16
CA ISO	(515)	11	(53)	(557)	(163)	(687)	(566)	(10)
Rocky Mtn	(263)	0	(77)	(340)	(62)	(251)	(266)	74
Rest of RTO West	(1,105)	1	(209)	(1,313)	127	(709)	(1,045)	268
W Connect	(425)	(1)	(109)	(535)	(31)	(405)	(484)	50
Total	(2,432)	9	(453)	(2,876)	(212)	(2,236)	(2,469)	408

3.5.8 Operating Reserves

In this sensitivity, our objective was to isolate the impact of more efficient allocation of operating reserves from the impact of other variables. The difference in benefits in this case compared to the base case can be attributed to the change in operating reserves allocation. TCA achieved this by excluding the impact of operating reserves in both the

With RTO and Without RTO cases and calculating the benefits of other features of RTO West.

Summary of Benefits

The results summarized in Table 22 show that most of the fuel savings are eliminated by ignoring the impact of operating reserves.

Table 22: Operating Reserve Sensitivity Results

Summary of Benefits ($M)- Difference Between With and Without RTO - Operating Reserves								
	A	B	C	D	E	F	G	H
Sub-Region	Load Energy Payment	Uplift Payment	Spinning Reserve Payment	Total Load Payment A+B+C	Generation Cost	Generator Energy Revenue	Generator Net Revenue B+C+F-E	Net Impact G-D
ALBERTA	(9)	0	-	(9)	(3)	(9)	(6)	3
BRITCOL	1	(4)	-	(3)	(76)	(61)	12	14
CA ISO	1	(7)	-	(6)	9	(2)	(18)	(12)
Rocky Mtn	(69)	0	-	(69)	(44)	(106)	(62)	7
Rest of RTO West	(455)	0	-	(455)	79	(157)	(235)	220
W Connect	(217)	(1)	-	(218)	(53)	(211)	(159)	59
Total	(747)	(12)	-	(759)	(89)	(546)	(469)	291

4 Other Quantified RTO Impacts - Benchmarking

This section describes the quantitative benchmarking analyses. TCA gathered information from industry sources in several areas:

- Startup and operating costs for RTOs,[38]
- Startup and operating costs of exchanges,
- Costs of performing a schedule coordinator role, and
- Monetary valuation of impacts of unplanned outages (loss of load).

Each of these areas is addressed below.

4.1 Startup and Operating Costs for RTOs

The October 2000 "RTO West Potential Benefits and Costs" report estimated the RTO West expected startup costs at $82 million and the annual operating costs at $50 million. This estimate was based on the October 2000 study group's best estimate of the levels of staffing and startup costs anticipated.

TCA collected data related to costs to develop and maintain ISOs/RTOs in North America.[39] This effort was intended to provide insights into the *actual* operating costs of similar organizations in the United States and Canada. The cost data were collected from a variety of sources, primarily publications from the respective organizations.

Table 23 summarizes the data collected for each of the ISOs and RTOs in North America.[40] The table shows startup and annual operating costs where available. In all

[38] "RTO" is used in this Section and in Section 5 to represent the broad set of RTO organizations, including ISOs.

[39] Within this section the terms ISO and RTO are used interchangeably to represent, except where noted, functionality on the scale expected within the RTO West.

[40] Notes/Sources:

A. All values in $US.
B. Direct comparisons across regions must be undertaken with care. Some shared regional functions and cost responsibilities are handled outside of ISO cost structure.
C. Some start-up costs not reflected or associated with previous tight pool structure and cost recovery.
D. Cost values actual or projected for 2000 or 2001, except where noted.
E. New England annual depreciation and interest costs are accounted for outside of the NE-ISO tariff structure.
F. Ontario, PJM, New England, and NY values from Ontario Independent Market Operator (IMO) Business Plan 2001-2003, November 2000.
G. NY ISO transition costs were obtained from the NY ISO Annual Report, 2000.
H. ERCOT values taken from Public Utility Commission of Texas Docket 23320 filings.
I. Alberta values from Transmission Administrator (TA) and Power Pool of Alberta (PP) Annual Review / Report documents for 2000, and Cox Report (see note L), and as provided by EAL professionals.

cases, however, all-in per-megawatt-hour carrying costs (startup and operating costs) have been provided or derived for each ISO/RTO and are shown.

J. Ontario start-up costs based on 1999 - 2001 capital expenditures from the IMO Business Plan 2001-2003, page 32 ($CA 254 Million).
K. ERCOT start-up costs based on 2000 - 2001 capital expenditures as reported in the "Year 2001 ERCOT Fund Summary" in Docket 23320 filing.
L. California numbers are from 2001 and are from “Participant Charges at Electricity Exchanges, Pools and ISOs: Towards a Benchmarking Study,” prepared for the Power Pool of Alberta by Paul Cox, December 29, 2000, and revised May 9, 2001.
M. PJM is represented in several configurations in the table, and all configurations are included in the weighted averages. Since the costs of these configurations span the range of other ISO costs, this factor is not expected to materially bias the average.

Table 23: Startup and Operating Costs of ISOs/RTOs

	Annual O&M Costs ($ million)	Annual Amortized Depreciation and Interest Costs ($ million)	Total Annual Revenue Requirement with Debt & Interest ($ million)	Annual Energy (TWh)	Unit O&M Costs ($/MWh)	Unit Revenue Requirement ($/MWh)	Peak Demand 2000 (MW)	Transmission Miles	# FTE employees	Staffing FTE/TWh	Start-up Costs ($ million)
PJM (2000)	70.2	31.6	101.8	256	0.27	0.40	49,417	8,000	384	1.50	140
PJM without PJM West (2002)			128.9	256		0.50		8,000			
PJM with PJM West (2002)			137.3	314		0.44		13,100			
New York	53.7	6.9	60.6	149	0.36	0.41	30,311	10,800	222	1.49	82
New England	55.7		55.7	122	0.46	0.46	23,300	7,000	323	2.65	55
Calif ISO			228.0	270		0.84	45,990	25,526	544	2.01	
ERCOT	44.6	77.4	122.1	281	0.16	0.44	57,606	37,000	250	0.89	137
Alberta TA and SC	6.3		21.4	54		0.40	7,785	10,540	76	1.41	
Ontario	57.6	28.4	86.0	150	0.39	0.58	23,428	18,000	417	2.79	172
Weighted Average $/MWh RTO Carrying Cost						0.51					
Weighted Average $/MWh RTO Carrying Cost, Without CA ISO						0.45					

Several items should be noted when applying these numbers to the relative net merits of RTO West.

- Numbers should be viewed as "ball park," given, for example, the averaging of dollar values from different years.
- Application of these values to an RTO West valuation requires judgment about the comparable level of effort required for RTO West.
- Various attributes are not distinguished in the preceding table:
  - ISO costs may include upgrades that would have occurred with or without the RTO:
    - Regional upgrades
    - SCADA upgrades
    - Y2k upgrades
  - RTO West costs are direct costs, not adjusted for parallel savings by the TOs or CAOs.
  - RTO West costs do not include the costs of stakeholder participation in the development process.

However, the table shows that the carrying costs of an RTO generally group fairly tightly. With the exception of California, which is broadly believed to have encountered unusually high startup costs, the other RTOs are relatively tightly grouped in a range of $0.40/MWh to $0.58/MWh.[41] The weighted average cost of the existing RTOs in North America is approximately $0.45 to $0.51, with the lower value representing the case in which California and Alberta are excluded from the mix.

Given the annual energy throughput expected for RTO West[42] in 2004, per-unit costs such as these quoted above equate to approximately $127 million to $143 million per year, depending on whether California's costs are included in the mix or not.

As RTOs mature and more such organizations become operational, parties can hope that experience will drive startup and operating costs down. The data from ERCOT and Ontario do not necessary demonstrate that RTOs have yet benefited from this learning curve. Conversely, however, the startup of Ontario and ERCOT do suggest that costs are being contained rather than significantly increasing, as the California ISO's experience, taken alone, would have suggested. These data are therefore seen as solid benchmark for average ISO/RTO costs. To the extent that RTO West could "beat the averages" and start up and/or operate for less cost, the overall RTO West net benefits would increase.

[41] Even the $.58/MWh RTO, Ontario, is somewhat of an "outlier", with the next most costly RTO at $.46, and represents a relatively small service area.
[42] From the Energy Impact Analysis TCA estimated approximately 280 TWh annual energy.

4.2 Operations of Secondary Exchanges and SC Functions

The RTO West benefit/cost study group directed TCA to examine the costs of secondary transmission exchanges. TCA chose to broaden the review to include both energy and transmission exchanges and ultimately found that there are no exchanges that specialize in transmission products alone, and few that offer the exchange of transmission rights, for example, at this time.

TCA was also asked to examine the costs of operating a Schedule Coordinator (SC) function, the role played by market participants (or third-party agents) to provide market participant interfacing roles with RTO West.[43]

The discussion of these topics in this report has been grouped here for two primary reasons:

- Minimal cost data are available for both of these functions because providers are primarily private and in many cases the functionality is only partially in support of the exchange or SC function.
- Some of the exchanges will also provide from minimal to substantial portions of the SC functionality.

TCA used several techniques to collect data reflecting the costs of these services, including:

- Conducting an original survey of members of the Association of Power Exchanges,
- Conducting an original survey of SCs and Qualified Scheduling Coordinators (QSEs) in the California and ERCOT markets,
- Using previous benchmarking works,[44] and
- Looking at published data on provider's web sites.

The survey questions are included in Attachments 4 and 5.

TCA received generous feedback from SC organizations and especially from members of the Association of Power Exchange throughout the world. However, data in this area are difficult to regard as intercomparable or complete. The most of these organizations are private, without standardized offerings. Comparing cost information is therefore less than satisfying.

[43] The Schedule Coordinator role is a significant one in markets where scheduling is primarily seen as communicating bilateral arrangements, such as in the RTO West, California and ERCOT. In such regions where a centralized pool is not operated in conjunction with the ISO or RTO, the Schedule Coordinator is the primary party who matches "buyers and sellers" or generators and loads. This role thus requires sophisticated scheduling systems, settlement systems and contractual arrangements to track, and aggregate and disaggregate, both the ISO/RTO schedules and the underlying portfolios of various sub organizations.

[44] Namely Cox.

4.2.1 Energy Exchange Information

Table 24 shows the data collected from various sources related to exchanges.[45] In many cases the data are incomplete; this was not surprising, given the extensive set of data that TCA was trying to collect.

To arrive at a proxy for average exchange fees, those exchanges that provided transaction fees were averaged, using a simple averaging, and doubling the transaction fee where it applied to both sides of the trade. From this simple analysis, a proxy price of $0.10/MWh was arrived at.

The transaction fees provide a proxy for the all-in costs of the exchange, including a profit margin. However, only a fraction of RTO West throughput would use the services of an exchange, namely that fraction that is not traded directly through bilateral arrangements and that is not provided to the RTO for balancing, redispatch, or ancillary services.

Although using an exchange causes parties to incur such an added cost, market participants would not use an exchange unless they believed that the benefits of doing so increased the value of their transaction by an amount equal to or greater than the

[45] Notes/Sources for the exchange data are as follows:

A. No complete set of either startup and operating costs data, or transaction fee data, was provided. TCA chose to use the transaction fee data, where provided, to average for a simple proxy. Parties are advised to estimate actual costs, and relevance of exchange data for themselves.

B. To develop the transaction fee average, TCA doubled the transaction fees if the exchange applied the fee to both buyers and sellers. The transaction fee averaging used a simple average, rather than weighted average.

C. Anonymity was offered to those responding to TCA's survey; exchange names have been suppressed to this end.

D. Exchange data for exchanges 1 through 6 are from TCA's international survey of exchanges, winter 2001 – 2002.

E. Exchange data for exchange 7 were gathered from the exchange's public web site.

F. Exchange data for exchanges 8 through 11 are from Cox, op. cite.

transaction costs.[46] As a matter of fact, these types of exchanges exist today, regardless of the existence of an ISO or RTO; the use of an exchange is not a directly incurred incremental cost of putting an RTO in place.

Exchange costs often include the costs of scheduling with the system operator/RTO, thereby offsetting the need for SC infrastructure.

[46] The Energy Impact Analysis, did, however, assume that markets are liquid. To the extent an exchange is needed to ensure that, this cost can be seen as incremental, relative to the energy impact benefits.

Table 24: Summary of Exchange Costs

Exchange	Type(s) of Market(s)	Primary or Secondary	Annual Volume (ranges)	Number of Control Areas	Start-up Capital Cost US$Million	Operating Cost US$Million	Transaction Fee (per MWh) US$	Transaction Fee Applied to:
1	Energy: day-ahead and intra-day	Primary physical and secondary financial	40,000 GWh to 70,000 GWh	1	10.85	6.83	0.069	buyers and sellers
2	Energy: spot (hourly and blocks)	Not available	<10,000 GWh	6	11.60	Not provided	0.036	buyer and seller
3	Energy: spot, forward	Primary. An exchange to match bilateral trades.	<10,000 GWh	6 (note 1)	3.9	2.5		
4	Energy: day-ahead	Primary	10,000 GWh to 40,000 GWh	1	Not provided	3.9		
5	Energy: real-time, reserves	Primary	40,000 GWh to 70,000 GWh	1	4	4.0	0.138	buyers and sellers
6	Energy: day-ahead, forward	Primary	<10,000 GWh	1	2.5	Not provided		
7	Energy: spot, forward		10,000 GWh to 40,000 GWh		Not available	Not available	0.002	contracts
8							0.030	buyers and sellers
9	Energy: spot, forward; clearing facility		> 100,000 GWh			1.00	0.028	buyers and sellers
10			> 100,000 GWh	1		62.00		
11			> 100,000 GWh			5.70		buyers
Average charge per MWh traded (note 2)							0.10	

Notes: (1) Six Transmission Areas
(2) Transactions applied to buys and sells are doubled for purposes of average

4.2.2 Schedule Coordinator Costs

TCA conducted a survey of SCs and QSEs. However, few respondents provided meaningful information other than suggesting directly or indirectly that it is very difficult to provide cost information because their operations are integrally connected to their other business functions. TCA therefore has no broad quantitative results to provide related to this topic.

There are, however, several pieces of information that may be useful to those contemplating the effort to establish this SC functionality.

First, exchanges, as described above, to greater or lesser extents provide scheduling services in addition to exchange platforms. Therefore, the exchange fees quoted above may also cover some SC functionality. Perhaps the most applicable case of this to the northwest markets is the services provided by the Automated Power Exchange (APX). Although conceived primarily as an exchange, APX has found its competitive advantage to be its ability to provide full-service SC services. APX provides these services in the California ISO market and in ERCOT and further was selected by ERCOT to be the "Default QSE," able to provide QSE services should any other QSE default, for example.

APX charges $0.0625/MWh to schedule power into the California ISO and $0.08/MWh for scheduling in ERCOT. These fees provide one indicator of the cost of providing SC services. Generally, small market participants may rely on APX for schedule coordination, because startup costs and the costs of 24/7 operations are viewed as prohibitive relative to the simple transaction fee. Mid- and large-sized participants, on the other hand, generally prefer to establish their own SC functionality, and they must therefore find that it is cost-effective, all things considered, to be their own SC, relative to the $0.0625/MWh and $0.08/MWh APX fees. This provides some understanding of order-of-magnitude costs.

Additionally, many of the functions of the SC overlap with existing infrastructure, so that not all of the effort to provide schedule coordination is incremental. In the responses received, the SC role was viewed as being a value-added service. For one relatively small participant (approximately 1000 GWh/yr throughput), the startup costs were seen as nominal, with slight modifications made only to existing systems, policies, and procedures. Further, for this participant, personnel costs were minimal, because marketers, traders, and schedulers simply picked up the SC functions.

In summary, the cost to set up and operate as a Scheduling Coordinate is often seen as significant. However, upon inspection one finds that many of the SC functions are business functions that many participants are already providing. SC costs can be seen as bound by the costs charged by a full third-party provider such as the APX, because should a party not wish to make the initial and ongoing investment, they could choose to contract for the services at $0.06 to $0.08/MWh. Additionally, of survey respondents, at least a good fraction believed that their investment in the SC function produced net value for the organization.

4.3 Value of Loss of Load

The study group has had an interest in quantifying the financial impacts of reducing the number and/or duration of outages (loss of load, or LoL), should an RTO structure be shown to improve reliability. Although TCA was not tasked with quantifying such LoL reductions, TCA did endeavor to examine what has been published on their value.

Several appropriate sources of data were identified. First, voluntary load-reduction programs are in place throughout the country, generally paying hundreds of dollars per megawatt-hour of curtailed load.[47] For two reasons, however, such values may significantly underestimate the value of load interruptions. First, load curtailment programs have varying degrees of notification, but in all cases participants can anticipate being interrupted at some time. Awareness of the possibility of interruption varies widely, from optional daily participation, to calls by the ISOs or Control Areas, to a simple awareness of the likelihood of a curtailment resulting from the participant's agreement to participate in the programs. Second, with all the programs listed below, only a fraction of all load participates in the program. Assuming that loads whose opportunity cost is less than the payment for curtailment or possible curtailment participate, that means that for these other consumers, the cost of loss of load exceeds the value of the program compensation.

For involuntary load curtailments, several sources of data suggest that the impacts can be tens of thousands of dollars per megawatt-hour.

- A recent study performed on behalf of the California Manufacturers' Association found the impact of rolling blackouts in California to be approximately $30k/MWh.[48]

- Further studies have found values of LoL to range from $10k/MWh to $50k/MWh.[49]

[47] TCA collected some actual data, for example the CA Demand Relief program pays $500/MWh plus a capacity payment for participating of $20k/MW-month, the CA Discretionary load reduction program pays $500/MWh to $700/MWh, the NY Emergency Demand program pays at most $500/MWh, as does the PJM Emergency Load Response program. However, the effort did not look across all programs such as utility programs, nor did it attempt to capture all the relevant facts of each program. Order-of-magnitude impacts seem relevant here.

[48] "Impact of Continuing Electricity Crisis on the California Economy," AUS Consultants, May 2, 2001. Report suggests $6.8 billion direct costs and $14.9 billion of indirect costs. Given 20 hours of rolling blackouts and 3647 MW of total CA load, this represents roughly $30k/MWh.

[49] From Power System Economics, Steven Stoft, draft publication (publishing anticipated for May 2002), Part 2, "Reliability, Price Spikes and Investment." This section reports on a value of loss of load determined in Australia of $16k/MWh, and a LoL of $10k/MWh used for the purpose of purchasing

Regardless of the specific value employed, it is clear that a significant change in LoL duration or frequency, determined theoretically to accompany the implementation of the RTO, could easily amount to a significant potential benefit for the northwest.

installed capacity. The study further reports that trading agreements in England value loads at greater than $50k/MWh, although Stoft is unclear as to whether this is $US, or $CA

5 Additional Impacts: Qualitative Assessment

TCA investigated a variety of additional benefits and costs that were not quantified. These additional items are discussed in this section. Many of these benefits are viewed as material to impacts of an RTO, and the cited basis for RTOs often reflects these types of attributes. For this study, however, no quantification was attempted given the level of effort and likely controversial nature of the results. The study also did not attempt to evaluate the extent to which these benefits or costs have played out in other markets.

The additional areas of impact have been grouped into four topic areas:

- RTO focus, coordination and information exchange.
- RTO consolidation of functionality.
- Organizational relationships established by the RTO process.
- RTO independence.

Each of these areas is discussed below in more detail.

TCA also surveyed marketers in the northwest, addressing perceived benefits of the RTO. The results from that survey complement the direct discussions of the areas of benefits and follows at the end of this Section 5.

5.1 Focus, Coordination and Information Exchange

One of the major areas of impacts of an RTO comes from the improved ability for the broader system operator (RTO) to focus on operations in the region and to coordinate activities to allow for easy information exchange. Benefits in this area seem to far outweigh costs. This section presents the details of the benefits, followed by a discussion of neutralizing impacts and costs.

5.1.1 Potential benefits

There are many areas of potential benefits related to focus, coordination, and information exchange. These are discussed as follows:

5.1.1.1 Planned outage management

The Energy Impact Analysis examined the impacts of improved generation outage planning, by looking at the value of planning generator outages based on the more global northwest market, rather than within each control area. However, the RTO's "big picture" perspective will also allow it to make more accurate assessments of the effect of proposed maintenance schedules on reliability.

RTOs have the authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards. Control over transmission maintenance is a necessary RTO function because outages of transmission facilities affect the overall transfer capability of the grid. If a facility is removed from service for any reason, the power flows on all regional facilities are affected. These shifting power flows may cause other facilities to become overloaded and thereby adversely affect system reliability.[50]

For example, when the owners of a constrained interface between MAPP and MAIN tried to remove the line from service for maintenance, they found that 500 MW of flow remained on the line even after all scheduled transactions were terminated. There were so many transactions in the region at the time that transmission operators could not determine the source of this 500 MW loop flow and were unable to ask other parties to cut their schedules to permit the necessary maintenance.[51]

The RTO's "big picture" perspective will allow it to make more accurate assessments of the reliability effect of proposed maintenance schedules, taking into account system-wide effects and seasonal demand variations.

5.1.1.2 Reduced failure propagation and improved outage restoration

The geographically fragmented approach by which the transmission system is operated today can allow system operators in one area to act without realizing the security implications for other neighboring areas, frequently with significant consequences. A case in point is the massive outage in the west that occurred during the summer of 1996, when a Bonneville Power Administration transmission line sagged too close to a tree, causing a flashover that led to cascading transmission line outages and subsequent generation outages. In total, nearly 7.5 million customers lost power, for periods ranging from several minutes to as long as nine hours. Transmission systems in 14 states, Canada, and Mexico were affected. Key factors that allowed a single transmission line outage to lead to significant regional losses were inadequate contingency plans, operating studies, and instructions to dispatchers.[52] The existence of an RTO would have reduced, if not prevented, this event.

The RTO, through tightened communications and coordination, may reduce conditions that cause failures to propagate throughout an entire region, relative to the geographically fragmented approach by which the transmission system is operated today.

Furthermore, a single integrated operator would likely be able to restore system operation following an outage more quickly and in a more orderly way than can separate control area operators.

[50] FERC Order 2000, p. 319.
[51] Ibid, p. 40.
[52] *Western Systems Coordinating Council Disturbance Report for the Power System Outage that Occurred on the Western Interconnection August 10, 1996;* October 18, 1996, posted online at www.wscc.com/news_regrading_power_outages.htm.

5.1.1.3 Voltage/frequency management

Frequency oscillations outside of an acceptable range have the potential to impose damaging stresses on generating machinery and large motors and can upset the stability of the entire grid. It is not uncommon for neighboring control areas in the Eastern U.S. to experience frequency oscillations because of the interaction between generating units in their respective areas. An example of this type of interdependence among control areas within a region is presented in the *1998 MAAC Reliability Assessment* (April 28, 1999) www.maac-rc.org.

In the northwest the maintenance of voltage stability is of greater practical importance than frequency. The RTO West would likely provide increased ability to manage frequency and voltage given its broader information and broader, coordinated control of transmission and generation resources and loads

5.1.1.4 Loop/parallel path flow

Loop flows can pose a significant security challenge for the neighboring power grids because all the unscheduled electrical paths that lie outside of relevant control area boundaries are not under the control and oversight of a single operator whose systems must accommodate these unplanned power flows. According to an EIA report:

> This cross-over can create compensation disputes among the affected transmission owners. It also impacts system reliability if a parallel path flow overloads a transmission line and decisions must be made to reduce (curtail) output from a particular generator or in a particular area. An RTO with access to region-wide information on transmission network conditions, with region-wide power scheduling authority, and with more efficient pricing of congestion can better manage parallel path flows and reduce the incidence of power curtailment. [53]

Thus, the ability to better manage loop flow directly affects the reliability of the system; it should also allow for the removal of overly conservative Available Transmission Capacity (ATC) requirements and should ease intercontrol area checkouts and settlements, as described below.

5.1.1.5 Scheduling, System Monitoring, Checkouts and Settlements

Several categories of information exchange will be automated or will no longer be required with an RTO:

- Information on schedules, system state, and real-time flows on interacting transmission elements (nomograms);

[53] Energy Information Agency, *The Changing Structure of the Electric Power Industry 2000: An Update*, Chapter 7, October 2000, posted online at www.eia.doe.gov.

- Real-time check-out and coordination of schedules and reservations on inter-control area ties;
- Inadvertent interchange and accounting, data collection and data sharing, and settlement.

Much of the cost and complexity of an RTO arises from integrating the control areas and automating the management of information. The benefit of these activities is ongoing avoided effort in these areas. This results in the elimination of these costly activities within each control area, and more importantly efficiency improvements, possibly higher ATC levels, and better ability to manage the reliability of the system.

5.1.1.6 Impacts of a Single Control Area on Transmission Capacity and Regulating Reserves

Given the improved focus and coordination with an RTO, available transmission capacity (ATC) will likely increase[54] due to a variety of mechanisms:

- A reduced need to set aside transmission capacity to compensate for the inability to manage transmission and generation resources in neighboring control areas. Without the ability to have full knowledge of the actions of adjacent system operations or to have control over adjacent systems, ATC may have built-in levels of conservatism beyond the scheduling limits evaluated in the Energy Impact Analysis.
- Better scheduling of transmission line maintenance, as described in Section 5.1.1.1, should result in higher overall availability of transmission capacity.
- Standard approaches to defining path ratings and transfer capabilities. As stated in FERC Order No. 2000, an RTO of sufficient regional scope can make more accurate determinations of ATC across a larger portion of the grid using consistent assumptions and criteria.[55] Because the RTO would be at least partially responsible for developing standards and ATC criteria, such development should produce more consistent guidelines, which should ultimately allow higher levels of ATC.

5.1.1.7 Automatic Generation Control (AGC)

To the extent that benefits have not already been captured through the regional reserve sharing policies, AGC requirements will decrease mainly because of higher load diversity and larger geographic regional requirement determination.[56] Further, as with the impacts

[54] Such increases in ATC were not incorporated into the Energy Impact Analysis. Higher levels of ATC could be modeled, but for the difficulty in estimating the resulting increases of these factors with any degree of certainty.
[55] FERC Order No. 2000, p. 255.
[56] The October 2000 study quantified potential benefits of lower regulating reserve requirements and found that 364 MW fewer of regulating reserves would be required with the RTO due to the load diversity (295

of operating reserves in the Energy Impact Analysis, having available more efficient resources for regulating reserves will reduce the costs of reserves. Additionally, although the Energy Impact Analysis evaluated savings in operating reserves arising from more efficient provision of those reserves, as with AGC, single largest contingency requirements may further decrease with an RTO. To the extent that the single largest contingency causes higher levels of reserves to be required, the RTO may allow for eliminating the reserves for some of these contingencies.

Similarly, to the extent the northwest control areas have required additional reserves for use of non-firm transmission between existing control areas, this need should decrease or disappear within the RTO region as a result of the RTO overseeing all of the delivery of resources (energy or reserves) within the northwest. The need for reserves to cover interruptible imports is based on the fact that imports may be interrupted at the discretion of external system operators, whose actions cannot be controlled or anticipated. This risk is practically eliminated between all contiguous member control areas within RTO West, since a single control area operator would control them all. This significantly reduces reserve requirements. Additional reserves for on-demand obligations may not change, however, because contractual obligations may remain under a single control area.

5.1.1.8 Real-time Balancing Efficiency

With the consolidation of control areas, RTO West will have several options for performing real-time balancing and regulation. Depending on their choice of implementation and on the historical diversity of area control error (ACE) in the member control areas, RTO West may save significant resources through centralization of the regulation and balancing function as a single control area and the existence of a single, aggregated ACE. This will eliminate the need for management of inadvertent interchange between member control areas, which at present perform regulation and balancing individually with their own ACE. Schedules on what are currently inter-control area ties will be managed under a single control area, just the same as schedules on any internal transmission paths. This will permit an aggregation and simplification of the balancing and settlement function.

5.1.1.9 Long-term planning and expansion benefits

In Order No. 2000, the FERC states that the RTO must have ultimate responsibility for both transmission planning and expansion within its region, because "a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity performing these functions, there is a danger that separate transmission investments will work at cross purposes and possibly even hurt reliability."[57]

MW) and relaxed standards (69 MW). When valued at Bonneville Power Administration's cost of service this quantity of regulating reserves was valued at $28 million. TCA in this study has made no effort to quantify these savings or to validate the October 2000 study conclusions.

[57] Ibid, p. 486.

Moving to an RTO with regional authority for transmission planning would avoid current problems arising from transmission planning based on local or sub-regional needs. In the current environment, transmission expansion has not kept pace with the changing needs of the market. Although levels of commerce in electricity are increasing, very little is being done to increase the load serving and transfer capability of the bulk transmission system.[58] According to EPRI, failure to satisfy grid expansion needs is resulting in increasing frequency and duration of power disturbances and outages costing $50 billion per year.[59] These failures stem from three root causes: the existing institutions have incomplete information on actual operating conditions, their unilateral responses to conditions are often ineffective, and their approach to planning is myopic. The last point is particularly important, because current institutions consider only the *local* benefits of transmission investments and upgrades, although the actual benefits obviously extend well beyond the control area where the upgrade occurs.[60] The benefit of such investment is therefore undervalued, and improvements that are critical to the regional electricity needs are not made. The creation of a large, regional RTO will allow it to "address larger issues that affect an entire region, including planning and investing in new transmission facilities…."[61]

Generation additions would also likely be more optimal, given that an RTO will create more efficient locational price signals, and that a broader market will allow more efficient use of generating resources (more baseloaded units, and a reduced need for service area peaking units). As the RTO results in lower capacity requirements, benefits will be recognized in the long run through reduced need for additions to generating capacity.

5.1.2 Neutralizing impact of RTO Focus, Coordination, and Information Exchange

The above discussions link benefits in focus, coordination, and informational areas to the RTO. However, ongoing industry coordination may create benefits even absent RTO formation. To the extent this occurs, or would occur, benefits cannot be attributed directly to the RTO formation.

5.1.3 Potential costs of RTO Focus, Coordination and Information Exchange

Some parties believe that by forming a large, centralized RTO, the unique experience of the operators of individual transmission systems may be lost or diluted.

[58] Reliability Assessment 2000-2009, NERC, October 2000, p. 26.
[59] FERC Order No. 2000, p. 44.
[60] FERC 32,541 at 33, 702-03.
[61] FERC Order 2000, p. 63.

5.2 RTO Consolidation of Functionality

In addition to the benefits of coordination and broader perspective, the consolidation will also offer some direct efficiencies and cost savings.

5.2.1 Potential benefits

5.2.1.1 Cost Effectiveness

A single RTO should be more efficient as the breadth increases, thereby reducing costs relative to the sum of the costs of the individual control centers.

5.2.1.2 Having a Single OASIS Site Should Reduce Costs and Improve Liquidity

The benefits of having a single OASIS administrator are several. A single OASIS administrator over an area of sufficient regional scope would better allocate scarcity as regional transmission demand is assessed; promote simplicity and "one-stop shopping" by reserving and scheduling transmission use over a larger area; and lower costs by reducing the number of OASIS sites….[62] In addition, a single OASIS site for each region instead of multiple sites would enable transactions to be carried out more efficiently.[63] Finally, standardization should help liquidity within RTO West and should facilitate seamless trades across the RTOs.

5.2.1.3 A Single Region-Wide Tariff Will Reduce Costs and Encourage Market Competitiveness

Maintaining a single tariff should produce benefits in the overall effort required to maintain tariff language, relative to what is required with each transmission owner maintaining a tariff, and should reduce costs of operation for market participants using the tariffs. This should also provide the added societal benefit of leveling the playing field, thereby allowing broader market participation.

5.2.1.4 Standardized Business Practices

Terminology and operating practices vary with OASIS sites. Because current market participants have to deal with multiple OASIS sites, transactions are limited because of the complexity of dealing with different systems and understanding different procedures. In addition to standardized tariffs, other business practices will be standardized with the RTO, thereby reducing transaction costs of market participants.

[62] FERC Order 2000, p. 255.
[63] Ibid, p. 432.

5.2.2 Neutralizing impact

Similar to impacts related to focus and breadth, ongoing industry standardization may create benefits even absent RTO formation.

5.2.3 Potential costs

An RTO may be more complex and may therefore cost more for market participants to schedule and settle with than would each individual control area.

5.3 The RTO Formation Establishes New Relationships

5.3.1 Potential Benefits

5.3.1.1 The Legal Relationships Created by the RTO May Provide an Enhanced Business Structure

By working through legal liability issues, the formation of the RTO may reduce the total costs of managing liability between parties. This could manifest itself as the ability to more quickly establish business relationships, for example.

5.3.1.2 Credit Management is Formalized by the RTO

The RTO will put in place structures that will facilitate, to some extent, credit management and it may provide a forum for resolution of ongoing regional/local regulatory issues.

5.3.2 Potential Costs

5.3.2.1 Resources are Required to Form New Relationships

Although direct RTO costs are likely rolled into quantified RTO cost data, developing relationship structure requires stakeholder resources pre-RTO. For example, the considerable time involved in stakeholder processes such as this benefit/cost study is rarely valued as part of the cost to implement an RTO.

5.3.2.2 Entity Tax Implications

An RTO may result in new tax treatment. However, the details of such an assessment were outside the scope of this benefit/cost study.

5.4 The Independent Nature of the RTO

5.4.1 Potential benefits

The RTO's independent transmission maintenance scheduling is viewed by some to be advantageous. A transmission owner that also owns generation may have an incentive to schedule transmission maintenance at times that would increase the energy price, thus increasing generator revenues. A transmission company, not affiliated with any generators, would not have these same incentives. Similarly, RTOs may eliminate—through structural separation—the economic incentive to act in ways adverse to other control areas in the region. Finally, an independent RTO would remove any mechanism for influencing ATC values based on energy portfolios.

5.4.2 Potential costs

Separating transmission operations from generation operations requires formalizing management of the interrelationship of generation impact on transmission and transmission impacts on generation (e.g., formal procedures and/or markets would be needed for VAR control).

5.5 Survey of Marketers in the Northwest

5.5.1 Intent

To provide a validation of theoretical potential benefits, the study scope included a direct survey of market participants. TCA conducted telephone interviews on behalf of RTO West with seven market participants[64] to get their views on the pros and cons of RTO West as it is currently configured. The survey questions (listed below) were developed by the study group. The survey interactions themselves were often more wide-ranging than is suggested by the questions.

[64] Ten market participants were contacted, but only seven interviews were completed prior to completion of this report. They are: 1) Pennsylvania Power & Light (PP&L) Montana; 2) TransAlta Corporation; 3) UBS Warburg (formerly Enron); 4) Calpine Corporation; 5) Alberta Power Pool; 6) Mirant Americas; 7) Powerex Corporation.

Standard Survey Questions

(1) What do you see as being the benefits of having an RTO (and specifically, the footprint and configuration of RTO West)?
   - One-stop-shop for services
   - Single tariff
   - Single set of Business Practices
   - Competitive Ancillary Services market
   - Other

(2) What do you see as being the detriments of having an RTO (again, relating to RTO West)?
   - Reliance on one entity
   - Uncertainty, given the expectation that the RTO, once up and running, will determine the specific details that will affect marketing efforts.
   - Issues re: the configuration of RTO West
   - Seams issues
   - Other

(3) In answering the above questions, did the configuration/proposed operation of RTO West affect your answers?

Most participants took the interview seriously and appreciated the fact that RTO West would seek feedback from market participants and the opportunity to provide their own opinion. The seven market participants reached were mostly project developers or power marketers, with the exception of the Alberta Power Pool. Thus, they had a common standpoint and similar expectations of the market, as is reflected in their responses.

5.5.2 Outcome

Overall, participants expressed strong support for the formation of RTO West. The main benefits cited were (1) the elimination of rate pancaking, (2) the standardization and centralization of the tariff and of business practices, and (3) the prospect of increased market liquidity and transparency from a larger, centralized energy market. Other benefits, expressed by fewer respondents, included standardization of generation interconnection agreements, the reduction of transaction costs through one-stop shopping, and the likelihood of a more stable investment environment for capacity expansion.

The almost unanimous concern expressed by the respondents was that the current proposal runs the risk of undermining the objectives of RTO West. Specifically, most respondents felt that the grandfathering of transmission rights inhibits the creation of a liquid transmission rights market because incumbents may not have financial incentives to release these rights in a secondary market. A second concern expressed by the six power marketers was that the rules preclude a true level playing field in the market between new entrants and incumbents. In addition to the grandfathering of transmission rights, the transmission access fee also contributes to this sentiment. Although they acknowledged that the incumbents paid an access fee based on their company rate sheet, they pointed out that incumbents would receive congestion rights with transmission access, but new entrants would not. Under FERC Order No. 888, all transmission users were accorded congestion rights on purchasing transmission, but under RTO West only incumbents continue to receive this benefit. Further, the access fee would render a significant number of previously economical transactions uneconomical in the new regime.

5.5.2.1 Select Survey Participant Comments

Below are paraphrases of some individual comments received during the interviews. These were chosen either because they offer more detail on the above summary points or because they reflect a less heard, but valid, consideration.

- A single tariff is particularly advantageous to merchant generation, because it provides a stable investment environment in the form of a large regional, liquid, accessible energy market. This will help in securing project financing.
- Marginal cost of trading will likely decrease under RTO West.
- Alberta marketers will benefit tremendously for export and import purposes from standardization and tariff simplification under RTO West.
- Market participants may have to give up existing competitive advantages and create new ones, because markets under RTO West may demand different skill sets. For example, scheduling in WSCC was a core competence in the past, but may not be as important if RTO West "accepts all schedules." Rather, other skills such as settlement complexities may gain importance.
- Alberta power marketers would favor integration of BC Hydro into RTO West, because that would reduce the seams they would to cross in order to transact with the U.S. However, membership of Alberta in RTO West would face significant legal hurdles, as well as significant learning curves in terms of the incorporation of congestion rights and pricing in Alberta.
- Grandfathered transmission rights slow down market development, and should at least be phased out with time. The current proposal will likely create barriers to entry to new participants, because incumbents will have little incentive to sell transmission rights that are most in demand, namely those that are likely to face congestion.
- All generators, including existing ones, should be on generation interconnection agreements in order to create a level playing field.
- The absence of a day-ahead, centralized power pool will hurt market efficiency and flexibility to market participants.
- The efforts required to resolve seams issues with the other two RTOs may be better spent in integrating all three into a single Western RTO.

6 Market Concentration Analysis

6.1 Introduction and Objectives

A market concentration analysis of the RTO West region was performed as part of the benefit/cost study performed by TCA for the RTO West Filing Utilities. The objective of this analysis is to provide an initial estimate of the market concentration in the region both before and after implementation of the RTO. This analysis identifies geographic regions and load centers that are highly concentrated and that could therefore experience high prices as a result of market power abuse. This type of market concentration study reflects the concern of the Federal Energy Regulatory Commission (FERC) over market power in electricity markets, as is discussed in FERC Order No. 2000, *Regional Transmission Organizations*. As referenced in this Order, the Federal Power Act gives FERC the primary responsibility to ensure that regional wholesale electricity markets operate without market power. In Order No. 2000 the Commission found that RTOs would be needed to resolve impediments to fully competitive electricity markets. As independent entities with no financial interest in the wholesale market, RTOs will also reduce the potential for market power abuse by mitigating potential vertical market power.

To maintain ongoing market power analyses, the Commission proposes in Order No. 2000 that RTOs perform a market monitoring function, which would include monitoring transmission service, ancillary services, and bulk power markets, and providing reports on market power abuses and market design flaws. Appropriate market monitoring, FERC states, provides an objective basis to observe markets and, if appropriate, to produce reports and market analyses.

The market concentration analysis reported in this study was performed according to the FERC Competitive Analysis Screen (Appendix A of the FERC Electric Merger Policy Statement, Order No. 592) to provide a baseline for possible future strategic market power analyses in the RTO West region and for future filings with FERC by the RTO West Filing Utilities.

6.2 Definition of Market Power

Market power is generally defined as the ability of a particular seller, or group of sellers, to significantly influence the market price of a product to its advantage over a sustained period. Regulators typically look for a combination of incentive and ability, because ability alone does not necessarily mean that prices will be raised. However, experience with electricity markets in the United States and other countries makes it clear that the threat of market power is real and that the exercise of market power can result in prices above the competitive level.

There are numerous negative implications when market power is exercised, among which the following are perhaps the most significant:

- Inefficient operation of the electric power system as out-of-merit-order (expensive) generators are dispatched.
- Distorted incentives for technological investments as a result of distorted market signals.
- Compromised long-term system reliability resulting from distorted market signals and consequent insufficient investment and system expansion.
- Financial harm to consumers through higher prices.

Market power is often equated to market concentration, as it is in Appendix A of the FERC Electric Merger Policy Statement, Order No. 592. However, there is no direct theoretical link between the Herfindahl-Hirschman Index (HHI), or other measures of market concentration, and measures of market power. Therefore, although the HHI can be used as a simple indicator of the *potential* exercise of market power, it does not measure market power directly.

6.3 Market Concentration Analysis Methodology

6.3.1 Overview

The analysis presented in this study determines market concentration. A "market" in this context refers to the collection of all entities that can provide power to a geographic region under a specific set of conditions. In this analysis, each hour of the year is considered to fall into one of 12 "product markets" in each utility service territory: for each of the four seasons (winter, spring, summer and autumn), a given hour is categorized according to load as Off-Peak, On-Peak, and or Super-Peak. This analysis is performed for both the long-term capacity and the short- and mid-term energy markets, as described below under Native Load Obligation.

While it is useful as an initial screen, the market concentration analysis is inherently a snapshot analysis that does not take market dynamics into account. It is a measure of how access to the market is apportioned given a certain set of market conditions. If conditions change, for example through a change in price or transmission system state, the market concentration can change as well.

The standard U.S. Department of Justice (DOJ) anti-trust measure of market concentration,[65] and the index calculated in this analysis, is the Herfindahl-Hirschman

[65] U.S. Department of Justice and the Federal Trade Commission, "Horizontal Merger Guidelines," April 2, 1992. http://www.usdoj.gov/atr/public/guidelines/horiz_book/hmg1.html

Index (HHI). The data needed to calculate the HHI for an electricity market are the following:

- Market price of electricity.
- Marginal cost and ownership of potentially participating generators.
- Obligation of market participants to serve native load.
- Transmission costs.
- Available transmission capacity.

Once all of these variables have been evaluated, the economically and physically deliverable capacity of each generator can be determined. The generators are then assigned to the market participant that controls their output, either the owner of the plant or the purchaser in a long-term contract. The aggregate market participant shares, expressed as percentages, are then used to calculate the HHI as detailed below.

6.3.2 Steps and Assumptions for Market Concentration Analysis

The study of market concentration begins with a simulation of market conditions and prices in two scenarios, with and without RTO West in place. The outputs of these baseline market simulations, prepared using the production cost model GE MAPS, provide the foundation for the market concentration analysis.

The market concentration analysis is based on the Competitive Analysis Screen defined in Appendix A of FERC Order No. 592. This test is intended for use in evaluating proposed mergers, to determine if a market is or will become significantly concentrated as the result of a merger, and it has also been used by FERC in evaluating proposed RTOs. If there is a significant change in concentration as a result of the RTO implementation, or of a merger or acquisition, then a further analysis of the ability of market participants to exercise market power and thereby raise prices in an anticompetitive fashion may be warranted.

The goal of the market concentration analysis in this study is not to identify the market concentration implications of a proposed merger but to predict whether the electricity market in RTO West will be workably competitive and the extent to which the implementation of the RTO will affect market concentration in the RTO West region. It serves as an indication of whether the electricity market in RTO West is sufficiently concentrated to warrant concern about the potential exercise of market power by any one participant. This part of the analysis does *not* examine anti-competitive pricing or the potential impact of strategic behavior (raising prices or withholding capacity) on the region's electricity markets and customers. Such an analysis could be conducted as an additional phase in this study.

The following steps are required for performing the market concentration analysis:

- Definition and identification of geographic markets.
- Definition and identification of energy product markets.

- Identification of potential suppliers of each product to each geographic region.
- Determination of native load obligation assumptions.
- Calculation of market shares and market concentration in the identified markets.

6.3.2.1 Definition of Geographic and Product Markets

Geographic Markets

The first step in defining a geographic market is to select a load center from which to begin the analysis. The second step is to identify suppliers capable of serving this load center. Suppliers are included if they are able to deliver the product (accounting for transmission constraints, costs and losses) to the customer at a cost no greater than 5% above the competitive price[66] to that customer. Taken together, the load center and the set of suppliers constitute the geographic market.

Our analysis thus begins with determining load center/destination markets based on the similarity of nodal prices with in each load center. Next, for each load center, all potential suppliers that could compete to serve that destination market are identified. Nodal prices for all load centers in RTO West (from GE MAPS) are analyzed using a clustering technique to identify buses that could be aggregated into a distinct electricity market or load center. Each cluster of buses is then designated as a destination market.

The clustering analysis includes all generator buses in the WSCC and load buses of 115 kV or above, for a total of 1,949 buses. The prices at these buses, taken from the GE MAPS output for the "With RTO" case, are then analyzed using the FASTCLUST procedure in SAS, and 15 clusters of buses are identified as appropriate destination markets for this analysis. In general, the majority of buses in each control area clustered together, as shown in Table 25. For example, 86% of the buses in Avista, and 93% of the buses in British Columbia Hydro Authority, fell into a single cluster associated with that company. The buses that did not fall in this main cluster were scattered in other clusters, in most cases in small groups of one to eight buses.

Two companies clearly divided into multiple clusters: Idaho Power Co. and PacifiCorp East. Transmission data were used to determine whether these companies should in fact be subdivided into smaller destination markets. On this basis it was decided to divide PacifiCorp East into two markets, PACE-UT for the Utah bus and PACE-WY for the Wyoming bus. Idaho Power Co. (IPC) is modeled as a single destination market, because its transmission capacity did not justify splitting this market into sub-markets.

[66] The competitive price is the price that would be expected in the market if all participants had perfect information and there was no market power. In this analysis, we assume the hourly competitive price to be the locational price calculated by GE MAPS. The competitive price used for the market concentration analysis, as discussed in this section, is then the simple average of these hourly locational prices across all buses in each load center.

Table 25: Percentage of Buses in Clusters

Control area	Percent of buses in single cluster	Where applicable, percent of buses in additional clusters	
Avista	86%		
British Columbia	93%		
Bonneville	95%		
Idaho Power	47%	29%	
Montana Power	88%		
Nevada Power	91%		
NorthWest PUB	99%		
PacificCorp East	36%	23%	22%
PacificCorp West	76%		
Portland	99%		
Puget Sound	100%		
Seattle	100%		
Sierra Pacific	61%		
Tacoma Power	100%		

The general conclusion from the clustering analysis is that the control area territories are an adequate proxy for destination markets. It is interesting to note is that this analysis indicates that a number of control areas, representing 1,278 buses in total, could have been merged into one destination market. These areas are the following:

- Avista
- Bonneville Power Administration
- NorthWest Publics
- Portland General Electric
- Puget Sound Power and Light
- Seattle City Light
- Tacoma Power Utility

However, these control areas were modeled separately in the analysis in order to maintain separate identification of ownership and market shares.

The twelve product markets

For each geographic market, there are 12 electricity product markets to represent the range of market conditions under which potential market power is screened. These product markets are Off-Peak, On-Peak, and Super-Peak defined according to load conditions during each of the seasons winter, spring, summer, and autumn.[67]

The product markets within each geographic market and season are defined as Super-Peak, Peak, and Off-Peak loads. These loads are defined on the basis of the maximum single-hour load in that geographic region during the given season. Starting with that

[67] Winter is defined as December, January, and February; the successive seasons are corresponding successive three-month intervals. In other studies, spring and autumn are often combined into one "shoulder" period. However, given the importance of hydro resources in this region we believe that distinguishing between spring and autumn is essential.

maximum single hourly load in each season, the hours of the season are categorized as follows:

Super-Peak =	Load is at least 95% of maximum hourly load
Peak =	Load is at least 80% but less than 95% of maximum
Off-Peak =	Load is less than 80% of maximum

6.3.2.2 Identification of Potential Suppliers

Once the hours that fall into each of the product markets in a region are identified, the price associated with that product market is computed as the simple average of the market prices for those hours as calculated by the GE MAPS production cost model. Consistent with the DOJ/FTC Horizontal Merger Guidelines and the FERC Competitive Screen Analysis, a price threshold for market participation (105% of the average price) is used to screen out suppliers whose cost of supplying energy to the destination market, including costs for production, transmission, and losses, is too high to warrant their participation in the market.

A generating unit within the geographic market is considered able to participate in a given product market if its marginal cost is less than or equal to the price threshold. A generator outside the destination market is considered able to participate in a given product market if its marginal cost of electricity, adjusted for losses, plus the minimum transmission cost to the destination market, is less than or equal to the price threshold. Any generating company that owns a generating unit that meets either of these standards is considered to be economically capable of participating in the given product market.

Assumptions with respect to the availability and costs of hydroelectric generation are critical to this analysis. Unlike thermal generating units, whose available capacity typically varies only slightly between seasons, the capacity of hydroelectric units varies considerably between and even within seasons, and this can substantially influence the results of the market concentration analysis.

Although hourly schedules of hydroelectric units were available, hydroelectric availability data were aggregated in order to be consistent with the snapshot analysis for the 12 product markets defined for the market concentration analysis. The capacity associated with each product market was calculated as follows.

- First, we assumed that in all Super-Peak hours, the hydroelectric unit is available at its *maximum annual capacity*. Super-Peak periods are very short, ranging from 34 hours in winter to 71 hours in the autumn, so it is reasonable to assume that the resource could be available at its maximum capacity during the Super-Peak hours in all four seasons. This is true even though the historical maximum schedule in a given season may be less than the nameplate capacity.

- Second, for the Peak period in each season, we assumed that the level of availability will be equal to the *maximum scheduled capacity in that season*. In RTO West, Peak hours comprise more than half all operating intervals. However, the need to react to high prices may not necessarily exist during all those hours. Therefore, for the purpose of the market concentration analysis, it is reasonable to assume that the capacity available to react to high prices will be at the level corresponding to the highest output scheduled in a season.
- Finally, during Off-Peak hours, we assumed that the capacity available is equal to the *average scheduled capacity* in each season. This level is higher than the average use of capacity scheduled for Off-Peak hours, indicating that if it were necessary to react to higher than normal prices, hydroelectric resources could be used at the seasonal average scheduled levels. This assumption recognizes the reluctance of operators to increase the use of hydroelectric resources in Off-Peak hours to levels significantly exceeding the scheduled level.

Transmission Constraints

Transmission into the geographic markets is limited by the physical transfer capability of the transmission system. For the WSCC, transmission constraint data were taken from the WSCC path limits, as provided to TCA by the RTO West participants. For the purposes of this analysis, TCA assumed that transfer capability at each transmission constraint is apportioned pro rata to the generators on the upstream side of the constraint that have been found to meet the 105% economic test. A generator that requires transmission service across more than one constrained interface to reach the destination market will see its deliverable capacity reduced at each successive constraint. Regardless of the availability of low-cost power in the surrounding areas, the total capacity that can be imported from all generators outside of the destination market region cannot exceed the import capability of the transmission paths into that market. Generating capacity that meets the price threshold within the geographic market and that is not restricted by transmission constraints is considered to be 100% available to the local destination market.

The total power available to a product market in any destination market is a function of market price, the price at which generators can deliver power to the market, transmission capacity into the geographic market, and the native load obligations (if any) of the potentially participating entities.

6.3.2.3 Native Load Obligation in the Short-, Medium-, and Long-Term

Three levels of native load obligation are assumed for this analysis: (1) an obligation to serve 100% of the current native load, (2) an obligation to serve 80% of the current native load, and (3) no native load obligation.

The assumption of 100% native load obligation means that market participants are required to withhold a portion of their least-cost capacity from the wholesale market to satisfy their native load obligations and other long-term wholesale contracts. This is interpreted as representing the short-term market, when participants remain obligated to serve both long-term contracts and native load.

The 80% native load assumption represents the possibility that there will be some opportunity for native load customers to switch suppliers and buy energy on the wholesale market, while the remaining native load is served directly by the traditional supplier. This scenario is modeled by assuming that companies retain 80% of their current native load obligation, while the remaining 20% is able to buy energy from the competitive wholesale market. The significance of this test to the market concentration analysis presented here is that it allows examination of market concentration in the near term, but after some retail access has occurred.

In the third case, it is assumed that there is no native load obligation in any of the markets included in the analysis, so that all market participants are allowed to sell all of their power on the wholesale market. This can be interpreted as representing the long-term capacity market.

Transmission Availability and Native Load Obligations

The amount of transfer capability made available to the wholesale market decreases as the native load responsibility increases. To understand this relationship, examine the case of no native load obligation first. In this case, all of the load is participating in the wholesale market and all generators are supplying the wholesale market. In this situation, the starting point for the analysis assumes that no generators are operating and thus no power is flowing. This implies that the total transfer capability of the transmission system is available to transmit power for the wholesale market.

In contrast, the 100% of native load case assumes that companies must serve that load before they sell any power to the wholesale market. In this case, the starting point for the analysis assumes two things that are different from the previous case.

1. Available supply. The lowest-cost generators of each company are used to supply their native load and so are not available to the wholesale market.

2. Available transmission. The fact that native load is being served first means that power is flowing in the initial state of the system for the 100% of native load case, which means that not all of the transfer capability of the transmission system is available to the wholesale market. Some of the transfer capability is being used to serve native load, and only the unused portion is available for transmitting power

for the wholesale market. This remaining transfer capability is what is assumed to be available for the 100% of native load case. TCA modeled two levels of transfer capability available after native load is served: 40% available and 85% available. These values were based on a survey of available transfer capability values posted on WSCC OASIS sites and other regional transmission trading sites. Because of the inconsistency of these posted numbers, two levels of available transfer capability were modeled rather than one.

6.3.2.4 Calculation of Market Concentration

Market concentration is calculated in three steps. First, the database of the power system, including generators, production cost data, transmission lines and constraints, and transmission rates, is used as described above with a computer model to determine which generators can economically and physically supply each destination market. Each destination market is analyzed separately, and all suppliers that can supply each market are assumed to participate in that market (that is, in order to ensure that all potential suppliers are included in the calculation, the local demand is essentially modeled as infinite, allowing all suppliers the chance to participate). The second step is to determine the market share of each supplier. Finally, the market concentration index is calculated.

Market concentration is calculated according to the DOJ/FTC Horizontal Merger Guidelines, which use the Herfindahl-Hirschman Index (HHI). The HHI is the sum of the squared market shares (percentages) of each of the market participants:

$$HHI = \sum_{i=1}^{N} \left(100 * \frac{P_i}{\sum P_i} \right)^2$$

where

N = Number of market participants,
P_i = Total capacity of participant i that meets the price threshold and is deliverable to the destination market,.

As a screening test, the DOJ interprets HHI values as follows:

HHI range	Interpretation
HHI < 1000	Unconcentrated Market
1000 HHI < 1800	Moderately Concentrated Market
HHI 1800	Highly Concentrated Market

6.4 Market Concentration Analysis Results[68]

Charts for the market concentration and market share results are presented and discussed below. The complete set of tables and charts is provided in the accompanying electronic data. Recall that market concentration as indicated by HHI is only an indicator of potential market power, not a measure of market power itself. If a supplier were to attempt to exercise market power in the RTO West region, with the intent of raising the price, the result would likely be that more generators would become economical and would therefore be able to supply energy to the affected market. This increase in market supply would counteract the attempted exercise of market power.

Figure 3 and Figure 4 show HHI results for each destination market in the RTO West region, With and Without RTO. Each HHI result presented is the average value for the indicated market across the 12 product markets analyzed. The values for all markets except IPC and Sierra Pacific Power Company (SPP) are well above the range considered to be highly concentrated by DOJ and FERC.

Figure 3 compares the HHI values With and Without the RTO, assuming that companies retain 100% of their native load obligation. Figure 4 shows the average HHI values for the scenario in which companies have no native load obligation, so that the availability of generation for participation in the wholesale market is determined solely on economic grounds (the results for assuming 80% native load obligation are provided in the electronic data.)

Comparison of the two bars for each company within a single chart (see also the non-averaged charts presented in the electronic data) shows that the HHI values within any given destination market are not significantly affected by the implementation of the RTO. The figure shows that the implementation of an RTO does not necessarily result in a decrease in market concentration; it may even result in an increase in some regions. Although seemingly counterintuitive, these results reflect the fact that sufficient low-priced power is available throughout most of the RTO West region to serve each destination market.

[68] The Market Concentration results are based on the GE MAPS nodal prices calculated for the March 5, 2002 draft of the report. The changes to the GE MAPS nodal prices between the March 5, 2002 draft and this March 11, 2002 draft are expected to have minimal impacts on these results.

This result is better understood by reviewing the market concentration results in conjunction with the seasonal prices for each destination market. In general, one would expect to observe that as electricity prices decrease, fewer regional generators would be able meet the economic test (that is, to deliver energy at less than or equal to 105% of the local price). In this situation, even though the costs for transmission and losses after the RTO is implemented would be less, they could still be high enough to prevent distant generators from being competitive. This leads to the result that as prices decrease, fewer generators are able to meet the price threshold, which has the effect of raising market concentration.

A second way to interpret Figure 3 and Figure 4 is to compare the HHI values for a single company between the two figures. This comparison demonstrates that market concentration in the *wholesale* market tends to be higher when companies retain their native load obligation than when there is no longer an obligation to serve. The comparison across the figures shows that when companies serve their historic native load with the least expensive generation (Figure 3), leaving only the more expensive generation to serve the wholesale market, market concentration is higher than when all generation is made available to the wholesale market (Figure 4). The assumption of a native load obligation leads to higher HHI values in most markets and for most of the 12 product markets, because fewer suppliers have excess capacity available to serve the wholesale market. However, because the native load is being served by the least-cost generators, the native load costs would not be affected by strategic bidding in the residual wholesale market.

HHI values provide information on overall market concentration. Further insight into the market structure is provided by looking at the market shares of each individual supplier into the market. A complete set of figures and tables on market shares is provided in the electronic data. Figure 5 and Figure 6, provided as examples of these figures, show Summer Peak market share in the Portland destination market.

Figure 5 shows the market share of all suppliers with at least 1% of the Portland market (8 suppliers in all) with and without the RTO, assuming that the native load obligation remains. Figure 6 repeats this chart except that zero native load obligation is assumed. In both of these figures, BPA has the largest market share. The trading division of Pacific Gas & Electric, the PG&E National Energy Group, also has a noticeable share in the Portland market, reflecting the fact that PG&E has significant capacity, and aside from serving its own native load is analyzed here as its potential to serve only the Portland market. Note in Figure 5 that Portland General Electric (PGE) itself does not have any market share in the wholesale market when it is assumed to retain its full native load obligation. This demonstrates, for example, that PGE would import power to serve load above its historic native load level during the Summer Peak product market.

In general, the results convey the following points:

- Most destination markets in the RTO West region have HHIs that indicate a high degree of market concentration. This appears to result from the low overall regional electricity prices (see Table 26 and Table 27), rather than indicating high prices and market power. (See the charts in ‘TCA RTO-West HHI by Region.pdf’ and ‘TCA RTO-West HHI by Scenario.pdf’ in the electronic data for the summary of HHI values.)

- The companies listed below, which appear to behave as a single market according to the preliminary price clustering analysis, do in fact behave as a single market for many of the scenario’s 12 product markets. For example, see Figure 7.

    - Avista
    - Bonneville Power Administration
    - NW Publics
    - Portland General Electric
    - Puget Sound Power and Light
    - Seattle City Light
    - Tacoma Power Utility

  However, for the scenarios in which there is assumed to be no native load obligation, these markets no longer behave as one market, as indicated by the different market concentration indices. (See the full set of charts in the electronic data.)

- In general, the native load assumption has a greater impact on market concentration and market share than does the implementation of the RTO and the associated changes in transmission rates.

- BPA has the dominant market share for most or all of the 12 product markets in most of the destination markets. See Table 28. (See also ‘TCA RTO-West Market Share Summary Tables.xls’in the electronic data.)

- In a few destination markets, BPA is not the dominant supplier. The following companies have the dominant market share in their own, local destination market. Table 29 presents data for British Columbia. (See also ‘Market Share Tables.xls’ on the TCA web site.)

    - Bonneville Power Administration
    - British Columbia Hydro Authority
    - Nevada Power Company
    - Pacificorp East

Table 26: Threshold Prices - With RTO Case

Threshold Prices ($/MWh) in All Destination Markets – With RTO Case												
	Winter Super-Peak	**Winter Peak**	**Winter Off-Peak**	**Spring Super-Peak**	**Spring Peak**	**Spring Off-Peak**	**Summer Super-Peak**	**Summer Peak**	**Summer Off-Peak**	**Autumn Super-Peak**	**Autumn Peak**	**Autumn Off-Peak**
BC Hydro	82.13	52.55	37.19	36.75	32.87	31.27	32.31	30.42	30.05	44.98	43.42	36.99
Bonneville	59.33	40.58	33.45	32.56	30.30	26.99	36.26	31.95	26.08	46.27	43.99	37.30
Idaho Power Co	33.40	35.40	33.38	30.66	28.93	27.33	35.46	35.84	27.17	34.12	37.28	36.03
Montana Power Co	68.75	37.35	29.75	28.75	28.45	25.12	34.28	31.83	24.97	42.73	39.34	29.81
Nevada Power	42.12	31.96	28.22	34.31	33.26	27.53	45.99	42.74	28.96	37.95	36.02	29.56
NW Publics	43.75	39.55	33.55	33.47	30.15	27.08	33.86	31.04	26.25	44.16	41.47	36.70
Pacificorp—WY	56.14	34.85	28.60	33.50	30.16	25.41	45.64	35.63	27.09	40.70	38.29	29.90
Pacificorp—UT	51.78	32.22	26.10	33.38	30.24	24.43	44.00	34.91	25.49	36.61	34.18	26.74
Pacificorp West	64.72	39.38	33.62	31.21	29.72	27.03	46.81	35.65	28.83	46.03	44.05	37.25
Portland General Elec.	79.30	40.42	33.61	34.00	30.96	27.17	35.59	36.25	28.88	46.25	44.44	37.27
Puget Sound	56.55	39.39	33.52	33.02	32.11	27.19	41.98	32.03	28.42	46.62	45.18	37.54
Seattle City Light	56.18	39.89	33.61	33.31	31.10	27.15	31.90	30.97	29.41	46.92	44.55	37.26
Sierra Pacific	48.59	39.85	38.94	32.98	32.38	33.48	46.93	40.24	36.00	48.45	43.48	44.13
Tacoma Public Utilities	38.69	36.50	34.74	31.78	31.65	27.21	26.53	31.17	29.30	45.25	44.00	37.75
Avista	36.54	33.40	36.54	32.29	28.91	24.52	34.34	32.62	27.70	45.78	41.71	35.91

Table 27: Threshold Prices - With RTO

Threshold Prices ($/MWh) in All Destination Markets – Without RTO Case												
	Winter Super-Peak	**Winter Peak**	**Winter Off-Peak**	**Spring Super-Peak**	**Spring Peak**	**Spring Off-Peak**	**Summer Super-Peak**	**Summer Peak**	**Summer Off-Peak**	**Autumn Super-Peak**	**Autumn Peak**	**Autumn Off-Peak**
BC Hydro	75.93	51.22	38.23	33.87	31.28	31.64	34.84	32.61	33.68	51.42	47.49	41.72
Bonneville	75.66	47.00	37.41	34.42	33.02	30.34	42.21	38.49	28.91	56.09	48.45	45.91
Idaho Power Co	28.44	39.14	33.86	33.10	32.88	29.30	38.44	42.38	27.57	40.72	40.87	39.22
Montana Power Co	79.38	37.31	27.65	26.47	28.25	24.22	30.92	36.28	22.00	44.17	38.63	30.37
Nevada Power	52.08	37.18	30.57	40.11	41.01	29.38	99.32	65.60	31.05	49.38	41.73	31.20
NW Publics	55.14	44.94	37.01	35.42	33.08	29.92	40.06	36.35	28.88	50.37	46.83	45.45
Pacificorp—WY	64.72	39.76	30.21	34.94	34.43	28.23	62.15	47.32	27.98	51.45	42.52	33.45
Pacificorp—UT	61.25	36.08	27.03	34.45	34.20	26.37	60.46	45.67	25.20	48.21	38.51	28.53
Pacificorp West	70.63	43.90	35.43	31.76	31.48	29.15	60.40	45.72	30.74	56.45	47.80	43.66
Portland General Elec.	86.01	45.83	35.60	31.25	31.73	28.64	41.57	46.23	30.06	55.64	47.49	43.03
Puget Sound	72.24	46.47	38.26	36.76	36.11	31.31	51.37	39.41	33.32	57.94	50.50	46.76
Seattle City Light	71.18	45.85	37.76	35.61	34.45	30.52	37.93	34.72	35.38	54.51	50.81	45.71
Sierra Pacific	62.61	47.74	43.42	45.79	40.53	39.88	80.34	51.36	42.14	54.64	55.58	46.58
Tacoma Public Utilities	41.27	41.27	38.87	35.22	34.78	30.13	31.36	35.58	34.38	52.81	49.06	45.73
Avista	42.70	37.78	42.23	35.88	32.56	29.13	42.08	40.42	31.41	52.80	51.31	44.02

Table 28: BPA Market Share - Without RTO

BPA Market Share in the All Destination Markets – Without RTO, 100% Native Load Obligation													
Company	Winter Super-Peak	Winter Peak	Winter Off-Peak	Spring Super-Peak	Spring Peak	Spring Off-Peak	Summer Super-Peak	Summer Peak	Summer Off-Peak	Autumn Super-Peak	Autumn Peak	Autumn Off-Peak	Average
BCHA	37	27	47	32	32	50	27	24	47	34	28	23	34
BPA	65	64	66	79	78	71	78	78	72	67	65	41	69
IPC	49	25	34	43	38	33	31	26	39	24	23	18	32
MPC	68	73	72	81	79	90	82	81	91	74	74	46	76
NEVP	1	2	2	3	3	1	3	2	2	3	3	1	2
NWPUB	63	63	66	79	78	71	78	80	71	68	63	39	68
PACE-UT	9	11	12	11	10	10	11	10	12	9	10	5	10
PACE-WY	13	15	17	18	16	16	17	16	18	14	14	7	15
PACW	59	57	57	70	69	61	64	61	65	55	54	43	59
PGE	57	56	66	79	78	71	78	61	71	63	59	40	65
PSPL	64	64	65	78	77	71	78	78	71	67	65	40	68
SCL	64	63	65	78	77	71	78	79	68	67	64	40	68
SPP	35	40	38	41	35	36	35	31	38	28	27	23	34
TPU	67	65	65	79	78	71	80	79	70	69	65	40	69
WWPC	69	72	56	80	79	75	81	81	74	72	67	44	71

Table 29: Market Share in BC Hydro - With RTO, No NLO

Market Share in the BC Hydro Service Area – With RTO, No Native Load Obligation

Owner Name	Winter Super-Peak	Winter Peak	Winter Off-Peak	Spring Super-Peak	Spring Peak	Spring Off-Peak	Summer Super-Peak	Summer Peak	Summer Off-Peak	Autumn Super-Peak	Autumn Peak	Autumn Off-Peak	Average
British Columbia Hydro Authority	78.72	78.72	71.88	78.53	78.33	65.18	77.16	77.16	67.12	77.61	77.61	71.24	74.94
Bonneville Power Administration	8.96	8.98	10.48	9.43	9.68	13.74	10.46	10.52	12.96	9.17	9.19	9.38	10.25
Alberta	7.09	7.09	9.37	7.16	7.22	11.61	7.61	7.61	10.96	7.46	7.46	9.59	8.35
PG&E National Energy Group	1.25	1.25	2.27	1.24	1.27	2.70	1.33	1.34	2.75	1.49	1.49	2.61	1.75
Southern California Edison	0.52	0.54	0.87	0.47	0.48	1.03	0.48	0.49	1.04	0.67	0.61	0.98	0.68
Puget Sound Power and Light	0.59	0.59	0.74	0.41	0.40	0.81	0.38	0.39	0.70	0.59	0.57	0.75	0.58
Portland Gen and Electric	0.51	0.52	0.56	0.50	0.36	0.63	0.35	0.34	0.53	0.57	0.58	1.01	0.54
Seattle City Light	0.39	0.38	0.48	0.38	0.38	0.51	0.41	0.37	0.48	0.46	0.46	0.80	0.46
WAPA Upper Colorado	0.28	0.28	0.46	0.25	0.26	0.51	0.26	0.26	0.51	0.30	0.30	0.53	0.35
Idaho Power Company	0.23	0.23	0.30	0.23	0.24	0.39	0.25	0.24	0.43	0.28	0.27	0.47	0.30
Arizona Power Company	0.12	0.13	0.39	0.18	0.20	0.46	0.20	0.20	0.47	0.17	0.20	0.39	0.26
PacifiCorp East	0.16	0.16	0.33	0.16	0.16	0.37	0.16	0.16	0.35	0.17	0.18	0.31	0.22
Public Service Colorado	0.12	0.12	0.31	0.14	0.14	0.38	0.16	0.16	0.38	0.17	0.18	0.31	0.22
Montana Power Company	0.18	0.19	0.43	0.19	0.20	0.41	0.09	0.09	0.17	0.09	0.09	0.17	0.19
Sierra Pacific Power Company	0.15	0.15	0.26	0.15	0.10	0.23	0.10	0.11	0.22	0.18	0.18	0.32	0.18
PacifiCorp West	0.17	0.15	0.13	0.16	0.17	0.19	0.18	0.15	0.13	0.20	0.20	0.35	0.18
LA Dept. Water and Power	0.18	0.15	0.18	0.15	0.13	0.22	0.17	0.17	0.22	0.14	0.16	0.31	0.18
Salt River Project	0.05	0.05	0.13	0.07	0.07	0.16	0.08	0.08	0.17	0.07	0.08	0.15	0.10
Avista Utilities	0.11	0.10	0.13	0.06	0.06	0.13	0.03	0.03	0.05	0.04	0.04	0.05	0.07
Tucson Electric Power	0.02	0.02	0.07	0.03	0.03	0.08	0.04	0.04	0.08	0.03	0.04	0.07	0.05
San Diego Gas and Electric	0.05	0.05	0.04	0.02	0.02	0.05	0.02	0.02	0.05	0.03	0.02	0.04	0.03
Public Service New Mexico	0.01	0.01	0.05	0.01	0.02	0.07	0.02	0.02	0.07	0.01	0.01	0.03	0.03
Nevada Power Company	0.01	0.01	0.04	0.02	0.02	0.05	0.02	0.02	0.05	0.02	0.02	0.04	0.03
North West Publics	0.02	0.02	0.03	0.02	0.02	0.03	0.02	0.02	0.03	0.02	0.02	0.03	0.02
Empire District Electric Company	0.01	0.01	0.03	0.01	0.01	0.03	0.02	0.02	0.03	0.02	0.02	0.03	0.02
Imperial Irrigation District	0.02	0.01	0.03	0.01	0.01	0.03	0.01	0.01	0.03	0.02	0.02	0.03	0.02
WAPA Upper Missouri	0.07	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
WAPA Lower Colorado	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tacoma Public Utility	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HHI	**6331**	**6331**	**5372**	**6310**	**6284**	**4583**	**6124**	**6125**	**4803**	**6167**	**6167**	**5266**	**5822**

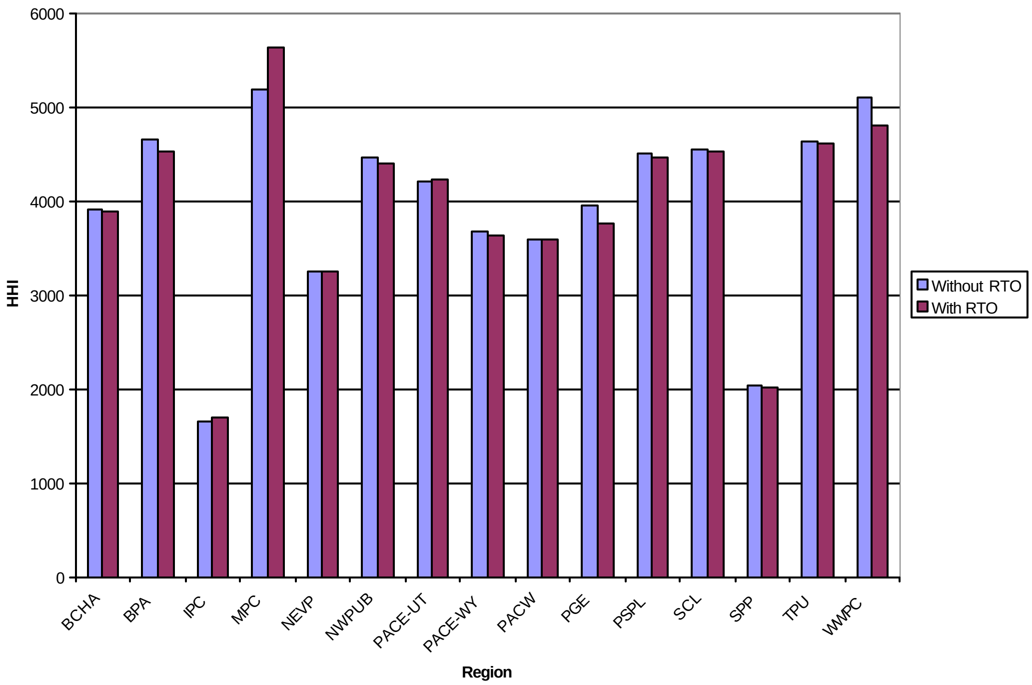


Figure 3: Average HHI, With and Without RTO, 100% NLO

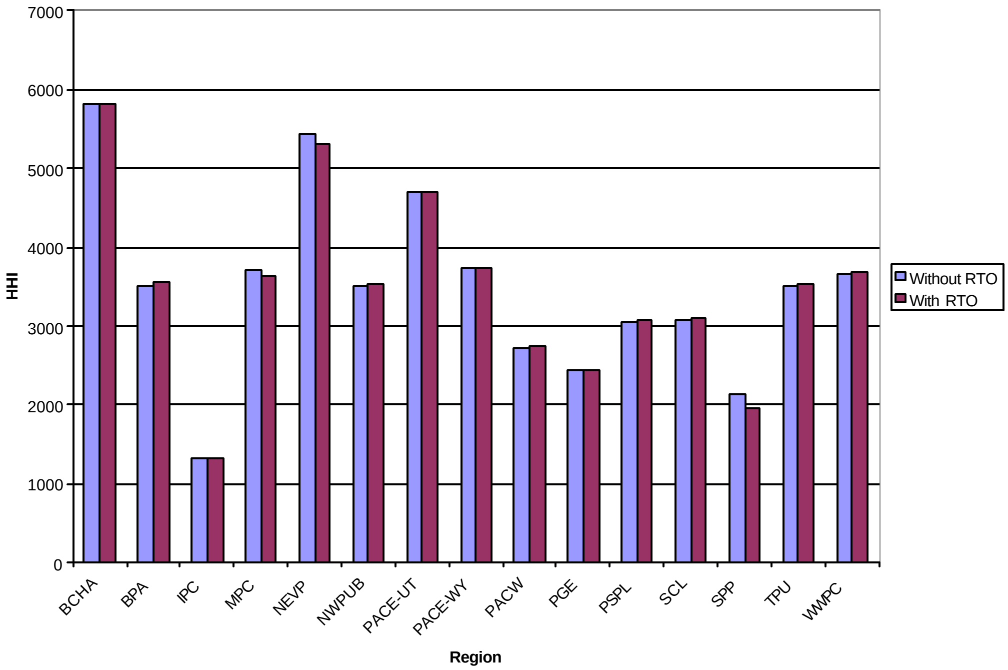


Figure 4: Average HHI, With and Without RTO, non NLO

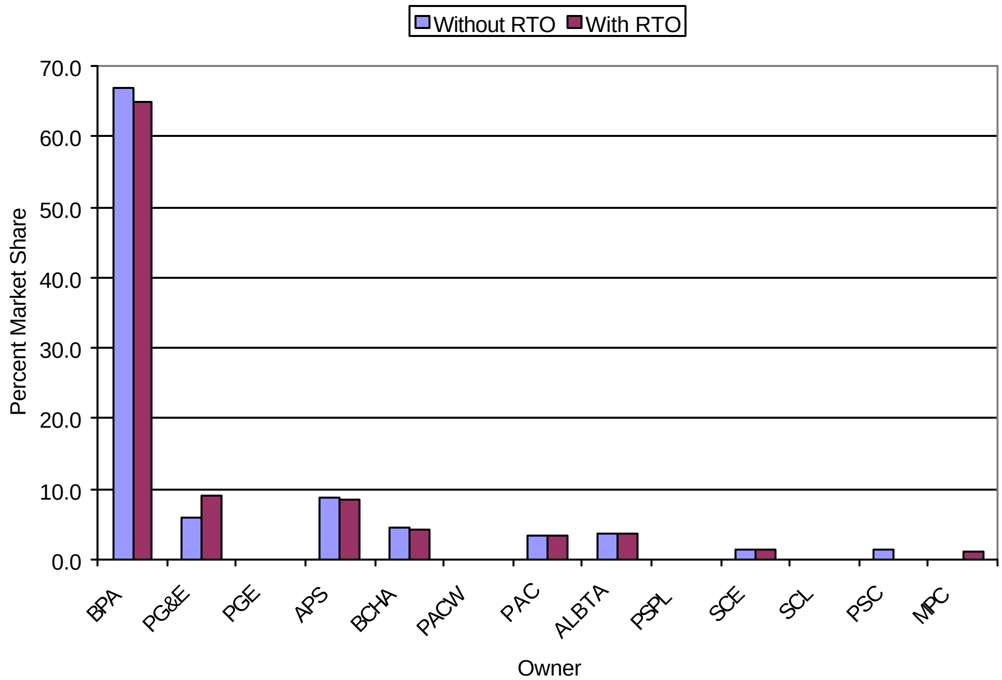


Figure 5: Summer Peak Share in Portland General Electric, With and Without RTO, 100% NLO

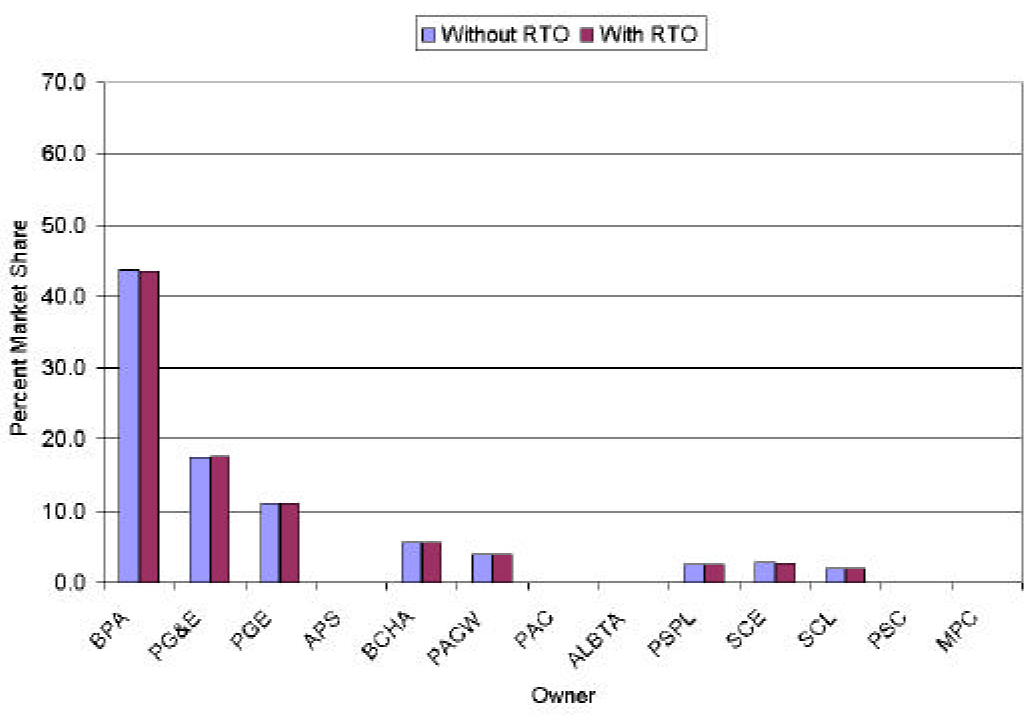
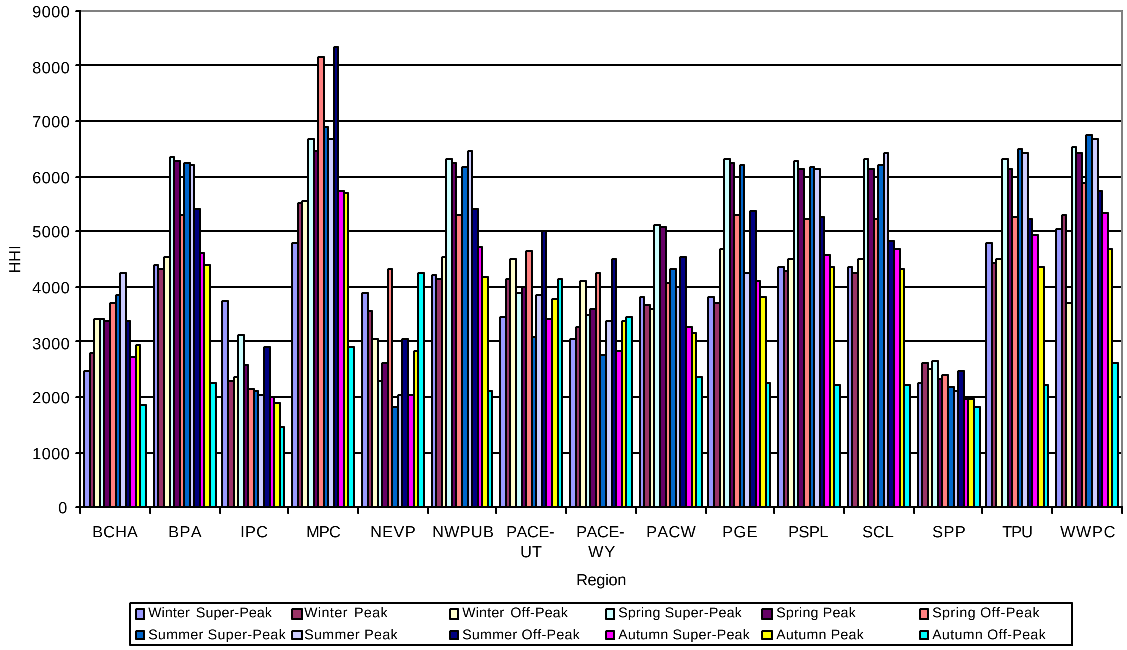
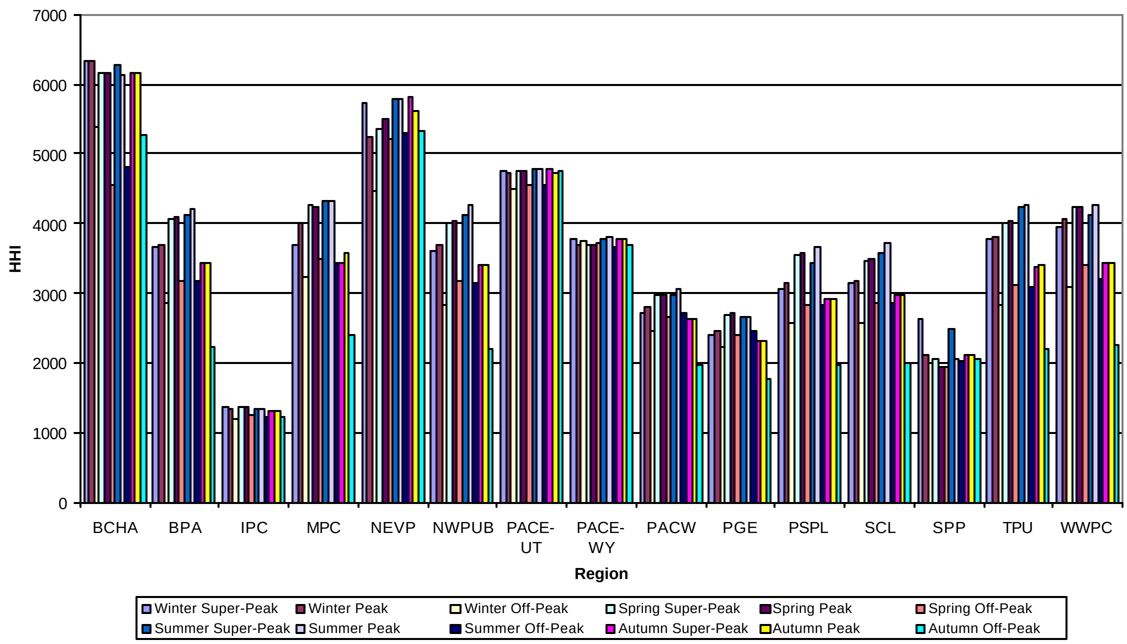


Figure 6: Summer Peak Share in Portland General Electric, With and Without RTO, no NLO



Full Native Load Obligation



No Native Load Obligation

Figure 7: HHI results for all seasons and load levels: Without RTO

7 Conclusion

The RTO West Benefit/Cost study, commissioned by northwest stakeholder group to further investigate the merits of RTO West, was reflected in this report. Methodology and assumptions directed by the work group are captured in this analysis, and results are presented.

The report shows benefits from an Energy Impact Analysis, both in the terms of production cost savings and from the benefits of consumer and producer surplus, also represented as a reduction in congestion rents. The results further seem robust, given the sensitivity analyses, to all but significant changes in the most fundamental drivers (pancaked rates and sharing of resources for reserves).

Costs of RTOs are captured through benchmarking, as are estimated costs of using secondary exchanges and schedule coordinator services. Finally many other impacts, predominantly found to be benefits, are presented qualitatively in this report.

Although the several study areas reported on here cannot necessarily be collapsed to produce a single conclusion on the quantitative merits of implementing RTO West, the magnitude of the potential savings reported in the Energy Impact Analysis, relative to the industry costs of RTOs, suggests that the benefits could outweigh the costs. The qualitative impacts—predominantly benefits—would tend to strengthen this conclusion. It is the northwest's producers and consumers, however, who must ultimately determine whether the sum of the quantifiable and unquantifiable benefits are greater than the economic and social costs.

Attachment 1: Input Assumptions

MEMORANDUM

TO: RTO West

FROM: Assef Zobian, Ellen Wolfe, Leslie Liu, Prashant Murti, Peter Capozzoli;
Tabors Caramanis & Associates

RE: Western System Coordinating Council Modeling Inputs Assumptions

DATE: September 20, 2001 (Revised February 26, 2002)

This memo summarizes the inputs to the TCA locational price-forecasting model (GE MAPS) for the Western part of the USA and Canada (WSCC). For our market modeling and analysis, we used a full network transmission model including anticipated upgrades. The modeling was done for one year (2004) on an hourly basis and was carried out for two scenarios: status quo (base case) and the proposed RTO West. In both cases, a security-constrained least-cost unit commitment and dispatch assuming marginal cost bidding was performed.

As inputs to the model, TCA has compiled a complete database for the western electric power system based on public domain data sources including various FERC forms (Form 1, 714, 715), the WSCC EIA 411, the WSCC Path Rating Catalog, and the RTO West Benefit Cost Work Group. We have included in-house analysis to ensure data integrity, validity, and consistency of plant operations with market developments.

The following is a list of the major components of the model. The list is followed by a description of each component and the associated data sources.

(1) Load Inputs
(2) Thermal Unit Characteristics
(3) Planned Additions and Retirements
(4) Nuclear Unit Analysis
(5) Fuel Price Forecasts
(6) Transmission System Representation
(7) Environmental Regulations
(8) Conventional Hydro & Pump Storage Units
(9) External Region Supply Curves
(10) NUG Contracts
(11) Dispatchable Demand (Interruptible Load)

1. Load Inputs

Description: GE MAPS takes load inputs on an hourly basis (8760 per year) for each load-serving entity. GE MAPS manipulates the load profile in each year to account for the change in the day of the week at the start of the year. Loads were based on published data for annual energy in the year 2000. These values were then projected out to 2004 based on published growth rates for each load area for 2000–2004. Then the resulting 2004 energy values were factored upwards or downwards to match the sub-regional totals in the WSCC report. Peak load shape factors for each area were taken from the Aurora Model output as provided by RTO West. Finally, annual peaks were calculated using these factors together with annual energy for 2004. Load and energy for each area are listed in Appendix 1.

Data Sources: We used each company's FERC 714 filings and EIA-411 (Load and Capability) reports from the WSCC for both the actual 2000 hourly loads (in EEI format) and load forecasts (2000 submissions of 2000–2010 projections). We also used data provided to us by RTO West.

2. Thermal Unit Characteristics

Description: GE MAPS models generation units in detail, in order to accurately simulate their operational characteristics and thereby project realistic hourly prices. The following characteristics are modeled:

- Unit type (steam, combined-cycle, combustion turbine, cogeneration, etc.)
- Heat rate values and curve
- Summer and Winter Capacity
- Variable Operation and Maintenance costs
- Fixed Operation and Maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick start and spinning reserves capabilities
- Startup costs

When unit-specific data were unavailable, we developed heat rate curves for different units based on technology type and data points obtained from the data sources described below.

Data Sources: Our primary data source for generation characteristics was NERC's Electricity, Supply and Demand (ES&D) database, which contains unit type, fuel type (primary and secondary), capacity and heat rate data (until 1998).[69] We used NERC's Generation Availability Data System (GADS) database as a reference for forced and unforced outage rates, which bases outage rates on plant type, size, and vintage. We estimated operation and maintenance costs based on plant size, technology, and age, and supplemented our data with FERC Form 1 submissions, particularly for nuclear units.
Exhibits 1a and 1b show the generic data we use for all units in our database.

Exhibit 1a – Thermal Unit Characteristics

Unit Type	Size (MW)	FOM* ($/kW-yr)	VOM ($/MWh)	Minimum down time (hrs)	Minimum up time (hrs)	Heat rate Shape	Startup Btus (MBtu/ MW)
Combined Cycle		18	3	6	6	2 blocks, 50%@100% FLHR, 50%@100%	1
Combustion Turbine	<100	7	7	1	1	One Block	0
	>100	7	3.5	1	1	One Block	0
Steam Coal	<100	38	2	6	8	4 blocks, 50%@106% FLHR, 15%@90%, 30%@95%, 5%@100%	20
	<200	35	2	8	8	4 blocks, 50%@106% FLHR, 15%@90%, 30%@95%, 5%@100%	20
	>200	35	1	12	24	4 blocks, 50%@106% FLHR, 15%@90%, 30%@95%, 5%@100%	20
Steam Gas/Oil	<100	38	8	6	10	4 blocks, 25%@118% FLHR, 30%@90%, 35%@95%, 10%@103%	5
	<200	35	6	6	10	4 blocks, 25%@118% FLHR, 30%@90%, 35%@95%, 10%@103%	5
	>200	16	4	8	16	4 blocks, 25%@118% FLHR, 30%@90%, 35%@95%, 10%@103%	5
Steam Other		16	4	6	10	4 blocks, 25%@118% FLHR, 30%@90%, 35%@95%, 10%@103%	5
Nuclear		90	0	164	164	One Block	0
Geothermal		0	2	1	1	One Block	0
Wind/Solar		0	0	1	1	One Block	0

* FOM values include the following assumptions: $1.50/kW-yr for insurance and 10% of base FOM (before insurance) for capital improvements.

[69] In addition, we checked our data against the WSCC report entitled "Existing Generation and Significant Additions and Changes to System Facilities 2000 – 2010, Data as of January 1, 2001, Prepared by WSCC Technical Staff ."

Exhibit 1b – Thermal Unit Characteristics, cont'd.

Type	Size (MW)	Quick Start (% of Capacity)	Spinning Reserve (% of Capacity)	Forced Outage Rate (% of Year)	Planned Outage Rate (% of Year)	Total Unavailability (% of Year)
Combined Cycle		0%	10%	1.5	6.82	8.32
Combustion Turbine	<100	100%	90%	4.34	5.21	9.55
	>100	100%	90%	2.53	7.5	10.03
Steam Coal	<100	0%	10%	2.96	9.48	12.44
	<200	0%	10%	3.46	8.66	12.12
	>200	0%	10%	4.51	9.79	14.3
Steam Oil/Gas	<100	0%	10%	2.14	7.91	10.05
	<200	0%	10%	4.64	10.95	15.59
	>200	0%	10%	4.01	12.04	16.05
Steam Other		0%	10%	3.09	7.27	10.36
Nuclear		0%	0%	9.03	11.35	20.38
Geothermal		0%	0%	2.22	8.18	10.4
Solar		0%	0%	70	0	70
Wind		0%	0%	50	0	50

3. Planned Additions and Retirements

***Description**:* Planned entries and retirements impact the fuel mix of installed capacity and the composition of plants on the margin. Most retirements are oil or steam gas plants, which are likely to be replaced by combined-cycle gas plants. We entered new capacity in the model for the next few years based only on existing projects in development or projects in advanced stages of permitting, as indicated by environmental permit applications and internal knowledge.

We expect that new capacity will most likely take the form of either gas-fired combined-cycle (GTCC) or simple-cycle gas turbines (SCGT), based on the relative economics of their entry. Below are the capital cost, performance and financing assumptions we used for new entry:

Exhibit 2a – New Entry Assumptions (Real 2000$)

Cost Component	CCGT	SCGT
All-In Capital Cost ($/kW)	600–700	340–450
Debt:Equity Ratio	65:35	40:60
Return on Equity	16%	16%
Cost of Debt	8%	8%
Term of Debt	20 years*	20 years*
Fixed O&M ($/kW-yr)	15	5
Variable O&M ($/MWh)	2	3.5
Full Load Heat Rate (Btu/kWh)	6,900**	10,000
Standard Units Size S. (MW)	230	480
Standard Units Size W. (MW)	250	500
Forced Outage Rate	3%	4%
Planned Outage Rate	4%	3%

** After 2006 we assume the heat rate decreases to 6800 Btu/kWh.

Known new entries and retirements are summarized in Appendix 2. A capacity balance for the subregions of the WSCC is included in Appendix 3.

***Data Sources**:* State Departments of Environmental Protection (DEP) were our primary source of planned projects that have a reasonably high degree of certainty. We also incorporated trade press announcements, power pool load and capacity reports, and internal knowledge in our analysis.

4. Nuclear Unit Analysis

***Description**:* We used a combination of market knowledge, the Nuclear Regulatory Commission (NRC) watch list, and economic performance as reflected in model runs to determine whether any nuclear units should retire prior to their license expiration. We used a three-year (1995–1997) average of O&M costs and revenue projections from model runs to assess units' economic performance. We also incorporated maintenance schedules and current outages posted on the NRC website.

We also incorporated maintenance schedules and current outages posted on the NRC website. A fixed maintenance schedule is shown in Appendix 4.

***Data Sources**: NRC*, trade press announcements, and FERC Form 1 data (for O&M costs).

5. Fuel Price Forecasts

***Description**:* GE MAPS takes monthly fuel prices for all plants. We modeled fuel-switching capability and the seasonality of gas prices in order to accurately simulate dispatch behavior. Our fundamental assumption of bidding behavior in competitive energy markets is that generators will bid in their *marginal cost*. In the case of gas, this is the opportunity cost of fuel purchased (in addition to variable O&M and environmental adders), or the spot price of gas at the closest location to the plant. We therefore used forecasts of spot prices at regional hubs, and further refined these based on historical differentials between price points around each hub. For oil and coal we used estimates of the price delivered to generators on a regional basis. For residual oil, we applied our own price differential between prices of residual oils of different sulfur content.

Actual proposed fuel prices are contained under a separate attachment.

6. Transmission System Representation

***Description**:* We used a full transmission system representation including transformers, AC and DC lines, phase shifters and buses, and modified by RTO West to include planned upgrades expected between now and 2004. Every unit and load was mapped electrically, and flow limits were defined for interfaces. These limits varied seasonally as specified by RTO West. For DC interties, the historical maintenance schedule for 2001 was used, and wheeling charges were based on current rates. Dispatch was subject to flow constraints, and flow limits on lines, interfaces, and binding constraints were monitored.

All monitored constraints have hard limits, i.e., very high overload costs, and MAPS re-dispatches resources to meet the limits. In addition, there are seasonal limits with minimum, average, and maximum Total Transfer Capabilities. These limits were used when they differed from the 2001 Path Rating Catalog. The minimum limits were assigned low overload cost, which allows MAPS to exceed this minimum limit if there is large price differential, or high congestion cost (higher than the assigned overload cost). Similarly, the average limits were assigned intermediate cost, which allowed MAPS to exceed the limit if the congestion cost was higher than the assigned overload cost.

All major transmission projects proposed for WSCC with an on-line date before summer 2004 were included in this study (starting with the WGA load flow case for 2004). The following is a list of some of these projects:

- Path 15 upgrade
- Falcon to Gonder 345 kV project
- Centennial Transmission (SNV)

Transmission nomograms
We added the following Nomograms to capture the relation on transfer limits on dependent interfaces:

- Path 15 (Midway Los Banos)/Path 17 (Borah West) was provided by BPA
- Path 20 (Path "C") was provided by PacifiCorp
- Southern California Import Total (SCIT) from the CAISO website.

For a listing of constraints, interfaces, seasonal ratings, transmission nomograms, and contract path limits, see Appendix 5.

Data Sources*:* We identified and monitor potentially binding lines and interfaces as listed in the 2000 WSCC Path Rating Catalog and FERC 715 filings. In addition we increased transfer capability over those interfaces where we believed transmission upgrades would be added. We used the contract path limits that were used in the report "Conceptual Plans for Electricity Transmission in the West, Report to the Western Governors' Association," August 2001.

7. Environmental Regulations

Description: We also added VOM values associated with scrubbers (SOx reduction) to units that already installed such equipment and incorporated these VOM values in the marginal cost bids. Further, we added to the marginal cost bids the opportunity cost of SOx tradable permits for all units, based on their current emission rates, and current allowance trading prices. We assumed the cost of SOx tradable permits to be $200/ton of sulfur emission. Exhibit 3 shows the units in New Mexico that have environmental controls and the associated cost adders for these controls.

We did not include tradable permit costs for NOx in the marginal cost.

The Western Regional Air Partnership (WRAP) is a voluntary, regional collaboration of the Western states and tribal commissions to implement the recommendations of the Grand Canyon Visibility Transport Commission to reduce haze in the Grand Canyon. Although WRAP does not have any enforced air quality regulations related to SOx and NOx, they may consider the implementation of market-based initiatives to reduce haze in the future. For units with emission control technology, we added the VOM and FOM associated with these technologies based on EPA estimates.

Exhibit 3 – Illustrative Example: New Mexico Units with Environmental Controls

Plant Name	Unit ID	Boiler Type	Primary Fuel	SO2 Controls	NOx Controls	1998 SO2 (tons)	1998 CO2 (tons)	1998 NOx (lb/MM Btu)	1998 NOx (tons)	1998 HI (MMBtu)	Winter Capacity	Sulfur VOM (1998$/ MWh)	NOx VOM Adder (1998$/ MWh)
Four Corners	1	DB	C	WL	U	3,892	1,595,729	0.73	5,932	15,557,071	170	1	0
Four Corners	2	DB	C	WL	U	3,490	1,418,913	0.71	5,088	13,831,877	170	1	0
Four Corners	3	DB	C	WL	LNB	4,052	1,884,357	0.53	5,001	18,367,014	220	1	0.05
Four Corners	4	CB	C	WL	LNB	13,990	6,096,320	0.5	15,064	59,434,485	740	1	0.07
Four Corners	5	DB	C	WL	LNB	14,566	5,885,703	0.51	14,840	57,369,768	740	1	0.05
San Juan	1	DB	C	O	LNB	7,780	2,758,988	0.43	5,882	26,901,261	316	1	0.05
San Juan	2	DB	C	O	OFA	6,472	3,182,392	0.51	8,076	31,024,998	312	1	0
San Juan	3	DB	C	O	LNB	11,055	3,660,446	0.42	7,658	35,668,634	488	1	0.05
San Juan	4	DB	C	O	LNB	14,655	4,682,946	0.43	9,885	45,648,125	498	1	0.05

Data Sources: NOx and SOx emission rates were obtained from the "EPA Emissions Scorecard for 2000, Appendix B," on a unit-by-unit basis.

8. Conventional Hydro and Pump Storage Units

Description: GE MAPS has special provisions for modeling hydro units. Since hydro generation is a major component in WSCC, special attention was given to the modeling. The model considers all environmental and operating constraints, such as maximum and minimum river flows. We used historical seasonal patterns for each individual hydro unit as a proxy for future seasonal generation (monthly GWh). Also using historical data, we developed three scenarios of hydro conditions: a wet year, a dry year, and a median year.

We used the hourly hydro generation schedule for pondage units in the Pacific Northwest and British Columbia as provided to us by RTO West. GE MAPS takes this hourly schedule as an input and does not schedule the units otherwise. Other pondage and pumped storage units are scheduled based on published data. Monthly maximum and minimum generation and total energy are supplied GE MAPS, and GE MAPS schedules the units to meet these requirements and shave peak loads. Total monthly hydro energy by load areas appears in Appendix 6.

Data Sources: The ES&D database was used for unit capacities, and the EIA 759 and 860 (1992–1998) was used for historical monthly generation (GWh). In addition, we checked our data against the WSCC report entitled "Existing Generation and Significant Additions and Changes to System Facilities 2000–2010, Data as of January 1, 2001, Prepared by WSCC Technical Staff."

9. External Regional Supply Curves

Description: The connection to the eastern grid is modeled as a series of thermal units and load buses depending on the direction of the flow. The thermal capacities of these representative units are determined by the maximum export capability across tie lines. We used historical exports, combined with our expectation of future conditions in these areas, to project export levels and prices for each of the forecast years.

We modeled the DC links as imports and exports depending on price at their location. If the price was below $30/MWh, they exported to the eastern interconnect and ERCOT at full capacity. If the price was greater than $30/MWh, but less than $35/MWh, they exported at 50% of their capacity. For prices between $35/MWh and $40/MWh, there were zero exports. For prices between $40/MWh and $45/MWh, they imported at 50% of their capacity, and if the locational price exceeded $45/MWh, they imported at 100% of capacity. These units were modeled as multi-block thermal units with total capacity twice the capacity of the link. A list of all DC links connecting the WSCC to the eastern part of the US and Canada is shown in Exhibit 4 below.

Exhibit 4 – External DC Links to the Eastern Inter-connect

DC Link	Company	State	Summer Capacity (MW)	Winter Capacity (MW)
Artesia	El Paso	NM	200	200
Blackwater	Pub Svc NM	NM	220	220
McNeil	Alberta	AB	150	150
Miles City	Basin Electric	MT	200	200
Virginia Smith	Basin Electric	NE	200	200
Stegal	Basin Electric	NE	110	110

10. NUG Contracts

Description: There is no significant NUG capacity in the West except in California. If we believe that the same process of contract negotiation that occurred in the east will occur in the west, then it is reasonable to assume that all these units will be dispatchable by 2003. However, most of the NUG capacity available is in the form of co-generation units, and we assume that the steam generated by the unit is required. Therefore, although the NUG units are made dispatchable in 2003, we used a low heat rate of 6000 Btu/kWh, thus ensuring that these units will always run even when they are dispatchable. We believe that contracts recently signed by the California Department of Water Resources will not distort the economics of generation in the west in general and in California in particular. From the EIA 860 B database we found that most of the large NUGs have stream output, so we kept their heat rates. For small NUGs, which were aggregated, we could not match all units, so we decided to increase the heat rate of some of them (approximately half) to 10,000 Btu/kWh. Exhibit 5 below shows the NUG capacity by state.

Exhibit 5 – NUG Capacity by State

Area	Capacity (MW)
Alberta	55
British Columbia	160
Arizona	50
California	7,237
Colorado	605
Idaho	99
Montana	104
Nevada	609
New Mexico	0
Oregon	542
Utah	53
Washington	678
Wyoming	45

11. Dispatchable Demand (Interruptible Load)

Description*:* We included in our modeling a representation of interruptible load to capture the effects on electricity prices. The presence of demand response is important to the energy and installed capacity prices. In the energy market, the value of energy to interruptible load caps the prices. The capacity of interruptible load works as installed reserves and lowers the capacity value. The size of interruptible load was determined as a percentage of total load for each region of the WSCC, and this percentage was applied to all load areas in the region. Dispatchable demand units were modeled as generators with a dispatch price of $400/MWh for the first block (50% of the company's dispatchable demand), and $8000/MWh for the second block.

In addition, we modeled aluminum smelters as interruptible non-conforming loads and assumed that they would be interrupted if the spot price of electricity exceeded $100/MWh. They did not have an hourly load shape and were modeled using dummy generators that turned on the quantity of the load once the price reached the requisite level.

Data Sources*:* We used interruptible load values based on the "Summary of Estimated Loads and Resources, Data as of January 1, 2001, Prepared by WSCC Technical Staff," as shown in Exhibit 6. Aluminum smelter information was based on our research.

Exhibit 6 – Interruptible Load Capacity (MW) by Region

WSCC Interruptible Demand by Region and Year																
Pool	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
ALBERTA	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
AZNM-SNV	791	326	341	347	350	353	357	360	361	363	365	367	369	371	373	375
BRITCOL	305	305	305	305	305	305	305	305	305	305	305	305	305	305	305	305
CA-MX	960	996	400	400	400	400	400	400	400	400	400	400	400	400	400	400
NWPP-US	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331
RMPA	118	118	118	119	119	119	120	120	120	121	121	121	121	121	121	121

Appendix 1

WSCC Load Forecast for 2004

Region	Load Area	Peak Load (MW)	Annual Energy (TWh)
BRITCOL	BC Hydro + W Kootenay	11,043	63,477
RTO West	Avista Corp	1,858	12,485
RTO West	Bonneville Power Admin	10,937	68,402
RTO West	Chelan Douglas Grant PUD	1,026	6,546
RTO West	Idaho Power Company	3,112	18,485
RTO West	Montana Power Company	1,187	7,748
RTO West	Nevada Power Company	5,261	20,971
RTO West	Pacificorp East	6,463	39,818
RTO West	Pacificorp West	4,296	26,150
RTO West	Portland General Electric	4,104	24,981
RTO West	Puget Sound Energy	4,254	24,999
RTO West	Seattle City Light	1,851	10,879
RTO West	Sierra Pacific Power	1,603	11,306
RTO West	Tacoma Public Utilities Light	1,434	8,428
ALBERTA	Alberta Power	8,333	57,278
CA-MX	LA Dept of Water & Power	5,803	31,691
CA-MX	Pacific Gas & Electric	28,305	138,101
CA-MX	San Diego Gas & Electric	4,032	22,020
CA-MX	Southern California Edison	19,429	106,109
Rocky Mtn	Public Service of Colorado	5,784	33,844
Rocky Mtn	WAPA Colorado-Missouri	3,375	20,624
Rocky Mtn	WAPA Upper Missouri	130	733
W Connect	Arizona Public Service Co	6,521	31,817
W Connect	El Paso Electric	1,105	7,782
W Connect	Imperial Irrigation District	816	3,922
W Connect	Public Service New Mexico	1,739	12,248
W Connect	Salt River Project	5,966	29,109
W Connect	Tucson Electric Power	2,312	11,279
W Connect	WAPA Lower Colorado	1,537	7,498

Appendix 2

New Entry Units in Alberta

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
ALBERTA	2001	Poplar Creek Ph 2	AB	CCg	Jan-2001	70	6,900
		Edmonton Cogen	AB	CG	Apr-2001	25	6,800
		Carseland Cogen [Transcanada]	AB	CG	Jul-2001	81	6,000
		Redwater Cogen [Transcanada]	AB	CG	Jul-2001	42	6,000
		Vision Quest I	AB	WND	Jul-2001	3	1
		Balzac Cogen [PanCanadian]	AB	CG	Dec-2001	103	6,000
		Cavalier Cogen [PanCanadian]	AB	CG	Dec-2001	104	6,000
		Sturgeon 3, Valleyview AB	AB	GTg	Dec-2001	92	10,000
		Vision Quest II	AB	WND	Dec-2001	24	1
	2002	Rainbow Lake II	AB	CCg	Jan-2002	46	6,900
		Oldman	AB	Pondage	Mar-2002		
		ATCO Power Oil Sands (Energen)	AB	CTg	May-2002	25	10,000
		Muskeg River	AB	CCg	Oct-2002	171	6,900
		Shell Scotford	AB	GTg	Oct-2002	160	10,000
		Calgary Energy Centre [Calpine](DF)	AB	CTg	Dec-2002	50	10,000
	2003	Calgary Energy Centre [Calpine]	AB	CCg	Dec-2003	250	6,900
	2004	AES Calgary CC (A,B,C)	AB	CCg	Jan-2004	525	6,900

New Entry Units in Arizona/New Mexico/Southern Nevada and in British Columbia

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
AZNM-SNV	2001	Desert Basin	AZ	CCg	Jun-2001	510	6,900
		Naniwa (TRI Center)	NV	CTg	Jun-2001	360	10,000
		South Point	AZ	CCg	Jun-2001	540	6,900
		Tucson CT1	AZ	CTg	Jun-2001	75	10,000
		West Phoenix CC 4	AZ	CCg	Jun-2001	121	6,900
		Griffith Energy CC1	AZ	CCg	Jul-2001	595	6,900
		Tucson CT2	AZ	CTg	Aug-2001	21	10,000
		Rye Patch	NV	GEO	Oct-2001	12	10,000
	2002	Redhawk CC 1&2	AZ	CCg	Mar-2002	1000	6,900
		Kyrene 7A	AZ	CCg	May-2002	250	6,900
		Arlington Valley	AZ	CCg	Jun-2002	500	6,900
	2002	Arlington Valley (DF)	AZ	CTg	Jun-2002	30	10,000
		Redhawk (DF)	AZ	CTg	Jun-2002	36	10,000
		West Phoenix CC 5	AZ	CCg	Jun-2002	500	6,900
		Panda Gila River CC1 (A-B)	AZ	CCg	Aug-2002	500	6,900
		Panda Gila River CC2 (A-B)	AZ	CCg	Aug-2002	500	6,900
		Las Vegas Cogen II	NV	CCg	Sep-2002	230	6,900
		Sempra Mesquite	AZ	CCg	Nov-2002	1000	6,900
		Sempra Mesquite (DF)	AZ	CTg	Nov-2002	140	10,000
	2003	Apex Industrial I	NV	CCg	Mar-2003	550	6,900
		Duke (Deming Power Plant)	NM	CTg	Jun-2003	506	10,000
		Harquahala Valley	AZ	CCg	Jun-2003	1000	6,900
	2004	Apex Industrial II	NV	CCg	May-2004	550	6,900

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
BRITCOL	2001	Island Cogen 1	BC	CG	Feb-2001	240	6,000
		Burrard Thermal 1	BC	STg	Jun-2001	150	6,900
	2002	Arrow Lakes	BC	Pondage	Apr-2002	170	
		Pingston	BC	Pondage	Jul-2002	30	
	2004	Brilliant Upgrade	BC	Pondage	Jun-2004	20	

New Entry Units in California

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
CA	2001	Mountain View Wind	CA	WND	Apr-2001	50	1
		3,5/01 Small Plant Aggregate (<100 MW)	CA	CTg	May-2001	19	10,000
		McClellan Upgrade	CA	CTgo	May-2001	22	10,000
		Chowchilla Peaker	CA	CTg	Jun-2001	49	10,000
		Fresno GT 1	CA	CTg	Jun-2001	18	10,000
		Harbor Generating Station (GT1-5)	CA	CTg	Jun-2001	240	10,000
		King City (Calpine)	CA	CTg	Jun-2001	50	10,000
		Procter & Gamble CG	CA	CTg	Jun-2001	44	10,000
		Valley GT1	CA	CTg	Jun-2001	48	10,000
		6,7/01 Small Plant Aggregate (<100 MW)	CA	GTg	Jul-2001	365	10,000
		Huntington Beach 3-4	CA	CCg	Jul-2001	450	6,900
		Los Banos Peaker	CA	CTg	Jul-2001	45	10,000
		Los Medanos Energy Center CC1 (Pittsburg District)	CA	CCg	Jul-2001	540	6,900
		Sunrise 1	CA	CCg	Jul-2001	320	6,000
		Sutter Power CC 1(A-C)	CA	CCg	Jul-2001	500	6,900
		Larkspur (Wildflower)	CA	CTgo	Jul-2001	90	10,000
		Indigo Energy Facility (1-3)	CA	CTg	Jul-2001	124	10,000
		Alliance Peaker Colton 1	CA	CTg	Aug-2001	40	10,000
		Alliance Peaker Colton 2	CA	CTg	Aug-2001	40	10,000
		Escondido GT2 (Calpeak Ent. #7)	CA	CTg	Aug-2001	49	10,000

New Entry Units in California, cont'd.

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
CA	2001	Red Bluff	CA	CTg	Aug-2001	47	10,000
		Drews	CA	CTg	Aug-2001	40	10,000
		8,9/01 Small Plant Aggregate (<100 MW)	CA	GTg	Sep-2001	437	10,000
		Calpeak Border	CA	CTg	Sep-2001	49.5	10,000
		Gilroy 1 - 3 (Calpine)	CA	CTg	Sep-2001	135	10,000
		Century	CA	CTg	Sep-2001	40	10,000
		La Paloma CC 1	CA	CCg	Nov-2001	262	6,900
		La Paloma CC 2	CA	CCg	Nov-2001	262	6,900
		La Paloma CC 3	CA	CCg	Nov-2001	262	6,900
		La Paloma CC 4	CA	CCg	Nov-2001	262	6,900
		Vaca-Dixon	CA	CTg	Dec-2001	49	10,000
	2002	Otay Mesa CC 1-4	CA	CCg	May-2002	510	6,900
		Elk Hills CC1	CA	CCg	Jun-2002	500	6,900
		Moss Landing	CA	CCg	Jun-2002	975	6,900
		Delta Energy Center	CA	CCg	Jul-2002	880	6,900
	2003	Contra Costa	CA	CCg	Jan-2003	488	6,900
		Mountainview Power Project	CA	CCg	May-2003	972	6,900
		Blythe Energy	CA	CCg	Jun-2003	473.2	6,900
		High Desert	CA	CCg	Jun-2003	662	6,900
		Pastoria	CA	CCg	Jun-2003	690	6,900

New Entry Units in the Northwest and Rocky Mountain

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
NWPP-US	2001	Gadsby (GT1-4)	UT	CTg	Jun-2001	100	10,000
		Klamath Falls	OR	CCg	Jun-2001	480	6,900
		Beaver 8	OR	CTg	Jul-2001	24	10,000
		Fredonia Addition	WA	CTgo	Aug-2001	106	10,000
		Mountain Home	ID	CTg	Oct-2001	90	10,000
		West Valley GT1-4	UT	CTg	Oct-2001	160	10,000
		Rathdrum Power CC 1 (COGENX)	ID	CCg	Nov-2001	265	6,900
		West Ridge	UT	CTg	Nov-2001	160	10,000
		Stateline Wind Project	OR	WND	Dec-2001	300	1
	2002	New Hydro 2	WA	Pondage	Jan-2002	500	
		Coyote Springs II (1&2)	OR	CCg	Jun-2002	42	6,900
		Frederickson	WA	CTgo	Jun-2002	249	10,000
		Big Hanaford (Centralia)	WA	STc	Jul-2002	248	12,000
		Hermiston CC (Umatilla)	OR	CCg	Jul-2002	550	6,900
		Goldendale CC	WA	CCg	Dec-2002	248	6,900
	2003	Satsop CC A&B	WA	CCg	Jan-2003	620	6,900

Area	Year	Full Name	State	Type	Install Date	Capacity	Heat Rate
RMPA	2001	Rawhide Diesels 1	CO	ICo	May-2001	40	15,000
		Fort Saint Vrain CC A&B, Platteville	CO	CCg	Jun-2001	235	6,900
		Fountain Valley / Midway [Enron]	CO	CTg	Jun-2001	240	10,000
		Valmont 8 [CO]	CO	CTg	Jun-2001	37	10,000
		Manchief 1&2	CO	CTg	Jul-2001	48	10,000
		Rock River	WY	WND	Oct-2001	50	1
		Brighton Station GT 1&2	CO	CTgo	Dec-2001	128	10,000
	2002	New CT-economic	CO	CTg	Jan-2002	250	10,000
		Plains End	CO	CTg	May-2002	108	11,000
		Limon Station GT 1&2 (TSGT)	CO	CTgo	Jun-2002	128	10,000
		Rawhide GT2	CO	CTg	Oct-2002	63	10,000
	2003	New CT-economic	CO	CTg	May-2003	250	10,000

Retired Units in the WSCC

Pool	Year	Full Name	State	Type	Date	Capacity	Heat Rate
CA-MX	2004	Haynes 3	CA	STgo	Dec-2004	222	9,219
		Haynes 4	CA	STgo	Dec-2004	222	9,603
RMPA	2001	Rawhide Diesels 1	CO	ICo	Oct-2001	40	15,000
	2003	Greeley Energy	CO	CG	Aug-2003	69	6,001

Appendix 3

Capacity Balance in the WSCC

Pool	Category	2001	2002	2003	2004
ALBERTA	Total Internal Demand	8,124	8,337	8,525	8,686
	Interruptible Demand	220	220	220	220
	Net Internal Demand	7,904	8,117	8,305	8,466
	Reserve Margin %	18	18	18	18
	Load + Reserve	9,327	9,578	9,800	9,990
	Firm Transfer	200	200	200	200
	EIA411 Capacity	8,708	9,024	8,780	8,781
	New Entry	544	452	250	525
	Retirement	0	0	0	0
	MAPS Capacity	9,686	10,125	10,375	10,900
	Balance	559	747	775	1,110
AZNM-SNV	Total Internal Demand	22,918	23,774	24,572	25,284
	Interruptible Demand	326	341	347	350
	Net Internal Demand	22,592	23,433	24,225	24,934
	Reserve Margin %	16	16	16	16
	Load + Reserve	26,207	27,182	28,101	28,923
	Firm Transfer	350	86	22	-12
	EIA411 Capacity	19,336	19,494	19,718	20,012
	New Entry	2,234	4,686	2,056	550
	Retirement	0	0	0	0
	MAPS Capacity	24,082	28,768	30,824	31,374
	Balance	-1,775	1,672	2,745	2,439
BRITCOL	Total Internal Demand	10,512	10,787	11,031	11,240
	Interruptible Demand	305	305	305	305
	Net Internal Demand	10,207	10,482	10,726	10,935
	Reserve Margin %	18	18	18	18
	Load + Reserve	12,044	12,369	12,657	12,903
	Firm Transfer	496	485	361	895
	EIA411 Capacity	10,715	11,104	10,803	10,805
	New Entry	390	200	0	20
	Retirement	0	0	0	0
	MAPS Capacity	12,872	13,072	14,072	13,092
	Balance	1,324	1,188	1,776	1,084

Capacity Balance in the WSCC, cont'd.

Pool	Category	2001	2002	2003	2004
CA-MX	Total Internal Demand	53,895	54,880	55,890	56,948
	Interruptible Demand	996	400	400	400
	Net Internal Demand	52,899	54,480	55,490	56,548
	Reserve Margin %	16	16	16	16
	Load + Reserve	61,363	63,197	64,368	65,596
	Firm Transfer	2,086	2,186	2,195	2,087
	EIA411 Capacity	54,567	55,226	55,272	55,274
	New Entry	4,948	2,865	3,285	0
	Retirement	0	0	0	444
	MAPS Capacity	59,303	62,168	65,453	65,453
	Balance	26	1,157	3,280	1,944
NWPP-US	Total Internal Demand	40,224	40,846	41,478	42,120
	Interruptible Demand	331	331	331	331
	Net Internal Demand	39,893	40,515	41,147	41,789
	Reserve Margin %	16	16	16	16
	Load + Reserve	46,276	46,997	47,731	48,475
	Firm Transfer	843	843	843	843
	EIA411 Capacity	52,492	52,986	53,494	53,494
	New Entry	1,685	1,837	620	0
	Retirement	0	0	0	0
	MAPS Capacity	55,611	57,498	58,118	58,118
	Balance	10,178	11,344	11,230	10,486
RMPA	Total Internal Demand	8,516	8,781	9,057	9,274
	Interruptible Demand	118	118	119	119
	Net Internal Demand	8,398	8,663	8,938	9,155
	Reserve Margin %	16	16	16	16
	Load + Reserve	9,742	10,049	10,368	10,620
	Firm Transfer	733	691	691	691
	EIA411 Capacity	10,784	10,805	11,006	11,208
	New Entry	778	549	250	0
	Retirement	40	0	69	0
	MAPS Capacity	12,488	12,997	13,247	13,178
	Balance	3,479	3,639	3,570	3,249

Appendix 4

Fixed Maintenance Schedule for WSCC Nuclear Units

Plant & Unit	Summer Capacity (MW)	Projected Forced Outage Rate	Projected Planned Outage Rate (Non-Refueling, Refueling Period)	Start Date for Refueling Outage										Outage Cycle Length (Months)
				2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	
Diablo Canyon1	1,073	6.0%	7.0%, 17.0%		23-Jan		23-Jan		23-Jan		23-Jan		23-Jan	24
Diablo Canyon2	1,087	6.0%	7.0%, 17.0%	4-Feb		4-Feb		4-Feb		4-Feb		4-Feb		24
Palo Verde1	1,258	6.0%	7.0%, 17.0%	31-Aug		1-Mar	31-Aug		2-Mar	31-Aug		2-Mar	1-Sep	18
Palo Verde2	1,258	6.0%	7.0%, 17.0%	13-Mar	12-Sep		13-Mar	12-Sep		13-Mar	12-Sep		14-Mar	18
Palo Verde3	1,262	6.0%	7.0%, 17.0%		8-Mar	6-Sep		8-Mar	7-Sep		8-Mar	7-Sep		18
San Onofre2	1,090	6.0%	7.0%, 17.0%	10-May		10-May		10-May		10-May		10-May		24
San Onofre3	1,080	6.0%	7.0%, 17.0%		18-Dec		18-Dec		18-Dec		18-Dec		18-Dec	24
WNP2	1,170	6.0%	7.0%, 17.0%	23-Apr		23-Apr		23-Apr		23-Apr		23-Apr		24

Appendix 5

Monitored Transmission Constraints from the WSCC 2001 Path Rating Catalog

Catalog Index	Constraint Name	Max Limit	Min Limit
1	Alberta-British Columbia	1000	–1200
2	- Back-to-back DC Converter -	-	-
3a	Northwest-Canada	2000	–3150
3b	Ing-Custer	2850	–2000
3c	BOUNDARY 230-NLYPHS 230- 1	400	–400
4	West of Cascades-North	9800	–9800
5	West of Cascades-South	7000	–7000
6	West of Hatwai	2800	–9999
7	- No constraint defined -	—	—
8	Montana to Northwest	2200	–2200
9	West of Broadview	2573	–9999
10	West of Colstrip	2598	–9999
11	West of Crossover	2598	–9999
12	Colstrip 500/230 kV Transf	500	–500
13	- No constraint defined -	—	—
14	Idaho to Northwest	2400	–1200
14a	Idaho-Northwest 500	1500	–9999
14b	Northwest-Idaho 230	1200	–1200
15	Midway - Los Banos	3600	–9999
16	Idaho-Sierra	500	–360
17	Borah West Actual	2307	–9999
18	Idaho - Montana	337	–337
19	Bridger West	2200	–9999
20	Path C Actual	1000	–1000
21	Arizona to California	5700	–9999
22	Southwest of Four Corners	2325	–9999
23	Four Corners 345/500	840	–840
24	PG&E - SPP	160	–150
25	Pacificorp/PG&E South	80	–30
26	Northern - Southern California	3000	–2400
27	- DC bi-pole -	—	—
28	Intermountain - Mona 345	1400	–1200
29	Intermountain - Gonder 230	200	–9999
30	TOT 1A Actual	650	–650
31	TOT 2A Actual	650	–650
32	Pavant/InterMt-Gonder Actual	245	–150
33	Bonanza-West Actual	735	–9999
34	- Replaced in 2001 PRC -	—	—
35	TOT 2C	300	–300
36	TOT 3 Actual	1250	–9999
37	TOT 4A	810	–9999

Catalog Index	Constraint Name	Max Limit	Min Limit
38	TOT 4B Actual	680	–9999
39	TOT 5 Actual	1675	–9999
40	TOT 7 Actual	890	–9999
41	Sylmar to SCE Actual	1200	–1200
42	2-FACE,COACHELV-MIRIID - 1	600	–9999
43	North of San Onofre Actual	2440	–9999
44	South of San Onofre	2200	–9999
45	California-CFE	408	–408
46	West of the Colorado R (WOR)	10118	–10118
47	NM1 Actual	925	–925
48	NM2 Actual	1692	–9999
49	East of Colo River (500–345)	7550	–9999
50	Cholla-Pinnacle Peak 345	1200	–9999
51	Southern Navajo	2264	–9999
52	Silver Peak-Control	17	–17
53	Billings-Yellowtail	400	–400
54	Coranado-Silverking-Kyrene	1100	–9999
55	Brownlee East Total	1560	–9999
55a	Brownlee East	1450	–9999
56	- Removed in 2001 PRC -	—	—
57	- No constraint defined -	—	—
58	ELDORADO- MEAD	1140	–1140
59	Eagle Mountain-Blythe 161 k	72	–72
60	Inyo-Control 115 kV	56	–56
61	LUGO 500-VICTORVL	900	–1950
62	Eldorado-McCullough 500 kV	2598	–2598
63	Perkins-Mead-Marketplace 50	1300	–9999
64	MARKETPLACE – ADELANTO	1200	–1200
65	- DC Intertie -	—	—
66	COI	4800	–3675
67–72	No limits defined	—	—
73	North of John Day	8400	–8400
74	No limit defined	—	—
75	Midpoint – Summer Lake	1500	–400
	Alberta North- South	1350	–9999

Individual Constraints from the WSCC 2001 Path Rating Catalog

Constraint Name	Max Limit	Min Limit
CRYSTAL 230-H ALLEN 230 1	950	-950
GOSHEN 345-GOSHEN 161 1	448	–448
BRADY 230-ANTLOPE 230 1	478	–478
MOENKOPI 500-FOURCO&2 500 1	1645	–1645
BICKNELL 345-VAIL 345 1	815	–815
CORONADO 345-SPRINGR 345 1	672	–672
GREEN-AE 230-GREEN-AE 345 1	150	–150
SAGUARO 500-TORTOLIT 500 0	672	–672
SOUTH 345-WESTWI&1 345 1	672	–672
SAGUARO 500-CHOLLA&2 500 1	888	–888
SILVERKG 500-CORONA&3 500 1	1732	–1732
MOENKOPI 500-NAVAJO&2 500 1	1482	–1482
MOENKOPI 500AFOURCO&2 500 1	1645	–1645
NAVAJO 500-MCCULLGH 500 1	1411	–1411
WESTWING 500-NAVAJO&4 500 1	1034	–1034
WESTWING 345-WESTWI&1 345 1	600	–600
HIDALGO 345-GREENLEE 345 0	717	–717
HATWAI 500-LOW GRAN 500 0	2182	–2182
COULEE 230-BELL BPA 230 3	414	–414
COULEE 230-BELL BPA 230 5	418	–418
COULEE 230-WEST 230 0	521	–521
COULEE 115-BELL BPA 115 0	155	–155
N LEWIST 115-DRY GH T 115 0	111	–111
HATWAI 230-LOLO 230 0	366	–366
LOLO 230-LOLO 115 1	125	–125
OXBOW 230-BROWNLEE 230 1	100	–100
OXBOW &3 230-LOLO 230- 1	478	–478
HELLSCYN 230-BROWNLEE 230 1	478	–478
MIDPOINT 345-MIDPOINT 230 1	500	–500
DIXONVLE 115-DIXONVLE 230 0	125	–125
HERNDON 230-KEARNEY 230 1	317	–317
MARTIN C 115-POTRERO 115 1	144	–144
MIDWAY 230-MIDWAY 500 1	1120	–1120
GATES 230-HENRETTA 230 1	753	–753
MC CALL 115-SANGER 115 1	224	–224
MONA 345-BONANZA 345- 1	650	–650
TRACY 500-LOSBANOS 500- 1	2122	–2122
TRACY 500-TESLA 500- 1	2122	–2122
BELLOTA 230-RNCHSECO 230- 1	488	–488

Constraint Name	Max Limit	Min Limit
BELLOTA 230-RNCHSECO 230- 2	488	–488
GOLDHILL 230-LAKE 230- 1	302	–302
COTWDPGE 230-COTWDWAP 230- 1	500	–500
TRACY 230-TESLA D 230- 1	333	–333
TRACY 230-TESLA D 230- 2	333	–333
GARRISON 500-GARRIS&1 500- 1	1732	–1732
GARRISON 500-GARRIS&3 500- 2	1732	–1732
NOXON 230-PINE CRK 230- 0	308	–308
RINALDI 230-OWENS 230 1	458	–458
CONTROL 115 INYOKERN 115 1	82	–82
CONTROL 115 INYOKERN 115 2	82	–82
INYO 230 OWENS 230 1	222	–222
CONTROL 230 OXBOW 230 1	183	–183
INYOKERN-KRAMER 115	165	–165
AMPS-PTRSNFLT	478	–478

Contract Path Ratings for the WSCC, 2004

Contract Path Name	Max Flows Export (MW)		Min Flows Import (MW)	
	Summer	Winter	Summer	Winter
ALBERTA -B.C.HYDR	1000	1000	-1200	-1200
ARIZONA -IMPERIAL	587	587	-387	-387
ARIZONA -LADWP	2761	2761	-1889	-1889
ARIZONA -NEW MEXI	2000	2000	-2000	-2000
ARIZONA -PACE	600	600	-590	-590
ARIZONA -SANDIEGO	1133	1133	-400	-400
ARIZONA -SOCALIF	3195	3195	-700	-700
ARIZONA -WAPA L.C	3739	3739	-5189	-5189
B.C.HYDR-NORTHWES	3150	3150	-2000	-2000
B.C.HYDR-W KOOTEN	588	588	-588	-588
IDAHO -NORTHWES	2400	2400	-1200	-1200
IDAHO -PACE	2100	2100	-1600	-1600
IDAHO -SIERRA	500	500	-360	-360
IMPERIAL-SANDIEGO	163	163	-163	-163
IMPERIAL-SOCALIF	600	600	-600	-600
LADWP -NEVADA	1620	1620	-1620	-1620
LADWP -NORTHWES	3100	3100	-3100	-3100
LADWP -PACE	1400	1400	-1920	-1920
LADWP -SIERRA	200	200	-200	-200
LADWP -SOCALIF	3400	3400	-3400	-3400
LADWP -WAPA L.C	1950	1950	-2120	-2120
MONTANA -NORTHWES	2200	2200	-600	-600
MONTANA -PACE	737	737	-737	-737
MONTANA -WAPA U.M	400	400	-400	-400
NEVADA -PACE	300	300	-300	-300
NEVADA -SOCALIF	637	637	-637	-637
NEVADA -WAPA L.C	1250	1250	-1250	-1250
NEW MEXI-PSCOLORA	224	224	-224	-224
NEW MEXI-WAPA L.C	700	700	-700	-700
NEW MEXI-WAPA R.M	600	600	-600	-600
NORTHWES-PG AND E	4880	4900	-3705	-3705
NORTHWES-SIERRA	300	300	-300	-300
NORTHWES-W KOOTEN	200	200	-200	-200
PACE -SIERRA	245	245	-150	-150
PACE -WAPA L.C	300	300	-300	-300
PACE -WAPA R.M	2370	2370	-2370	-2370
PG AND E-SIERRA	160	160	-160	-160
PG AND E-SOCALIF	3000	3000	-3000	-3000
PSCOLORA-WAPA R.M	2455	2455	-2392	-2392
SANDIEGO-OUTBACK	408	408	-408	-408
SANDIEGO-SOCALIF	200	200	-1800	-1800
SIERRA -SOCALIF	18	18	-18	-18
SOCALIF -WAPA L.C	1060	1060	-1060	-1060
WAPA L.C-WAPA R.M	400	400	-400	-400
WAPA U.M-WAPA R.M	300	300	-300	-300

Seasonal Operating Transfer Capabilities

PATH (WSCC path #)	2001 PATH RATING CAT. VALUE	Spring (April-May)				Summer (June-October)				Winter (November-March)			
		Approved Seasonal OTC 2001	Max OTC 2004	Mean OTC 2004	Min OTC 2004	Approved Seasonal OTC 2001	Max OTC 2004	Mean OTC 2004	Min OTC 2004	Approved Seasonal OTC 2001	Max OTC 2004	Mean OTC 2004	Min OTC 2004
COI (66)	4800 MW N-S 3675 MW S-N	4800 MW N-S 3675 MW S-N	4350 MW N-S 3675 MW S-N	4172 MW N-S 2840 MW S-N	2800 MW N-S 2450 MW S-N	4600 MW N-S 3675 MW S-N	4300 MW N-S 3675 MW S-N	4300 MW N-S 2949 MW S-N	2750 MW N-S 1908 MW S-N	4350 MW N-S 3675 MW S-N	4300 MW N-S 3675 MW S-N	4300 MW N-S 3485 MW S-N	2750 MW N-S 2000 MW S-N
PDCI (65)	3100 MW N-S 3100 MW S-N	3100 MW N-S 3100 MW S-N	3100 MW N-S 2084 MW S-N	2305 MW N-S 1549 MW S-N	0 MW N-S 0 MW S-N	2975 MW N-S 3100 MW S-N	2975 MW N-S 2200 MW S-N	2846 MW N-S 2043 MW S-N	0 MW N-S 0 MW S-N	2810 MW N-S 3100 MW S-N	2810 MW N-S 2200 MW S-N	2800 MW N-S 2032 MW S-N	0 MW N-S 0 MW S-N
North of John Day (73)	8400 MW N-S	8000 MW N-S	8000 MW N-S	7500 MW N-S	6500 MW N-S	8000 MW N-S	8000 MW N-S	7500 MW N-S	6500 MW N-S	7900 MW N-S	7900 MW N-S	7400 MW N-S	6500 MW N-S
North of Hanford	Not Rated		4300 MW N-S		3500 MW N-S		4300 MW N-S		3500 MW N-S		4300 MW N-S		3500 NW N-S
Cross Cascades North (4)	9800 MW N-S										9800 MW E-W		7500 MW E-W
Cross Cascades South (5)	7000 MW N-S										8200 MW E-W		6600 MW E-W
West of Coyote	Not Rated		4000 MW E-W		3100 MW E-W		4000 MW E-W		2900 MW E-W		4000 MW E-W		3100 MW E-W
South of Snoking	Not Rated		2700 MW N-S 2140 MW S-N		1700 MW N-S 1540 MW S-N		2700 MW N-S 2140 MW S-N		1700 MW N-S 1540 MW S-N		2700 MW N-S 2140 MW S-N		1700 MW N-S 1540 MW S-N
Raver-Paul	Not Rated		1820 MW N-S		1280 MW N-S		1820 MW N-S		1280 MW N-S		1820 MW N-S		1280 MW N-S
Keeler-Allston	Not Rated		1600 MW N-S		800 MW N-S		1600 MW N-S		800 MW N-S		1600 MW N-S		800 MW N-S
Alturas (76)	300 MW N-S 300 MW S-N	300 MW N-S 300 MW S-N	300 MW N-S 300 MW S-N		0 MW N-S 0 MW S-N	300 MW N-S 300 MW S-N	300 MW N-S 300 MW S-N		0 MW N-S 0 MW S-N	300 MW N-S 300 MW S-N	300 MW N-S 300 MW S-N		0 MW N-S 0 MW S-N
Sierra - Idaho (16)	500 MW N-S 360 MW S-N	500 MW N-S 262 MW S-N				500 MW N-S 262 MW S-N				500 MW N-S 262 MW S-N			
Sierra - PG&E (24)	160 MW E-W 160 MW W-E	120 MW E-W 100 MW W-E				120 MW E-W 100 MW W-E				120 MW E-W 100 MW W-E			
Sierra - Utah (32)	245 MW E-W 150 MW W-E	240 MW E-W 150 MW W-E				240 MW E-W 150 MW W-E				240 MW E-W 150 MW W-E			
Idaho - Northwest (18)	2400 MW E-W 1200 MW W-E	2400 MW E-W 1200 MW W-E	2400 MW E-W 1200 MW W-E		1200 MW E-W 800 MW W-E	2400 MW E-W 1200 MW W-E	2400 MW E-W 1200 MW W-E		1200 MW E-W 800 MW W-E	2400 MW E-W 1200 MW W-E	2400 MW E-W 1200 MW W-E		1200 MW E-W 800 MW W-E
Brownlee East (55)	1750 MW W-E	1750 MW W-E	1750 MW W-E		1560 MW W-E	1750 MW W-E	1750 MW W-E		1560 MW W-E	1750 MW W-E	1750 MW W-E		1560 MW W-E
Midpoint - Summer Lake (75)	1500 MW E-W Not Rated W-E	1500 MW E-W 400 MW W-E				1500 MW E-W 400 MW W-E				1500 MW E-W 400 MW W-E			
Bridger West (19)	2200 MW E-W	2200 MW E-W				2200 MW E-W				2200 MW E-W			

Seasonal Operating Transfer Capabilities, cont'd.

PATH (WSCC path #)	2001 PATH RATING CAT. VALUE	Spring (April-May)				Summer (June-October)				Winter (November-March)			
		Approved Seasonal OTC 2001	Max OTC 2004	Mean OTC 2004	Min OTC 2004	Approved Seasonal OTC 2001	Max OTC 2004	Mean OTC 2004	Min OTC 2004	Approved Seasonal OTC 2001	Max OTC 2004	Mean OTC 2004	Min OTC 2004
Borah West (17)	2307 MW E-W	2273 MW E-W (heavy load) 2307 MW E-W (light load)				2100 MW E-W				2307 MW E-W			
Path C (20)	1000 MW N-S 1000 MW S-N	830 MW N-S 775 MW S-N (heavy load) 900 MW	830 MW N-S 900 MW S-N		520 MW N-S 775 MW S-N	830 MW N-S 775 MW S-N (heavy load) 900 MW	830 MW N-S 900 MW S-N		520 MW N-S 775 MW S-N	870 MW N-S 785 MW S-N (heavy load) 950 MW	870 MW N-S 950 MW S-N		550 MW N-S 785 MW S-N
Alberta - BC (1)	1000 MW E-W 1200 MW W-E	1000 MW E-W 1200 MW W-E				1000 MW E-W 1200 MW W-E				1000 MW E-W 1200 MW W-E			
Northwest - Canada (3)	3150 MW N-S 2000 MW S-N	3150 MW N-S 2000 MW S-N	2800 MW N-S 2000 MW S-N	2075 MW N-S 1941 MW S-N	650 MW N-S 300 MW S-N	3150 MW N-S 2000 MW S-N	2800 MW N-S 2000 NW S-N	1898 MW N-S 1908 MW S-N	600 MW N-S 0 MW S-N	3150 MW N-S 2000 MW S-N	3150 MW N-S 2000 MW S-N	2522 MW N-S 1946 MW S-N	400 MW N-S 200 MW S-N
Montana - Northwest (8)	2200 MW E-W 600 MW W-E	2200 MW E-W 600 MW W-E	2175 MW E-W 1350 MW W-E	1983 MW E-W 1000 MW W-E	1750 MW E-W 600 MW W-E	2200 MW E-W 1350 MW W-E	2200 MW E-W 1350 MW W-E	1926 MW E-W 1000 MW W-E	955 MW E-W 600 MW W-E	2200 MW E-W 600 MW W-E	2200 MW E-W 1350 MW W-E	1990 MW E-W 1000 MW W-E	800 MW E-W 600 MW W-E
Montana - Idaho (18)	337 MW N-S 337 MW S-N	337 MW N-S 302 MW S-N				337 MW N-S 234 MW S-N				337 MW N-S 337 MW S-N			
West of Hatwai (6)	2800 E-W	2800 E-W	3600 MW E-W	3282 MW E-W	2100 MW E-W	2800 E-W	3600 MW E-W	3200 MW E-W	2100 MW E-W	2800 E-W	3600 MW E-W	3282 MW E-W	2100 MW E-W
Montana - Southeast	Not Rated	600 MW N-S 384-600 MW S-N (light load)	600 MW N-S 600 MW S-N		299 MW S-N	600 MW N-S 362-600 MW S-N (light load)	600 MW N-S 600 MW S-N		362 MW S-N	600 MW N-S 301-600 MW S-N (light load)	600 MW N-S 600 MW S-N		301 MW S-N

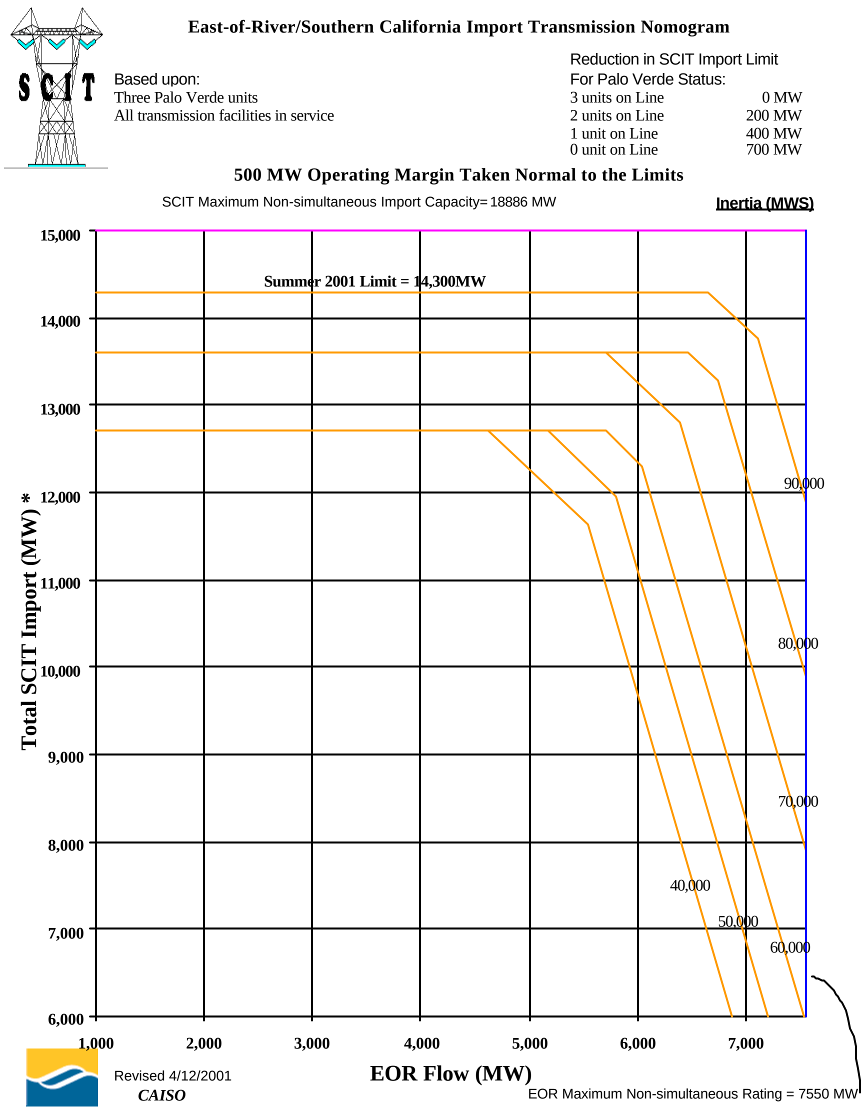
INFORMATION:

The seasonal OTC's are from NOPSG seasonal studies for the last year and adjusted to represent expected impacts from the G-9 projects. Notes below contain additional information. The approved seasonal OTC i

NOTES:

1. Max, Mean, Min OTC information in shaded rows provided by BPA.
2. Maximum seasonal OTC for COI is lower than seasonal OTC due to higher Northern California generation assumption.
3. The sum of the COI + Alturas schedules cannot exceed the COI OTC.
4. Actual Scheduling capability data for November 2000 - September 2001 was used for to define max, mean, & min OTC for COI, PDCI, NW-Canada, Montana-NW, and West of Hatwai.
5. PDCI is power order at the sending end (i.e., N-S flow at Celilo terminal, S-N at Sylmar terminal)
6. PDCI S-N limited to a maximum of 2200 MW due to lack of NW load tripping available for remedial action. May be limited further by West of Borah flow. PDCI limit is reduced 2 MW for every 1 MW the West
7. Maximum, mean and minumums for North of John Day are based on engineering judgement.
8. Max and min OTC for North of Hanford, Cross Cascades North & South, South of Snoking, West of Coyote, Raver-Paul, Keeler-Allston, Alturas, Idaho-NW, Brownlee East are based on no outage maximum and
9. Max and min OTC for Path C and Montana-SE are based on seasonal nomogram ranges.
10. For Path C & Montana-SE heavy load period is defined as 7AM-11PM MST. Light load period is defined as 11PM-7AM MST and all hours on Sunday and holidays.
11. Cross Cascades North & South are potential problems during extreme winter peak loads

Transmission Nomograms



*Sum of flows on Midway-Vincent, PDCI, IPP, North of Lugo, and WOR.

1999-2000 Winter --- Path C vs Bridger-Rock Springs

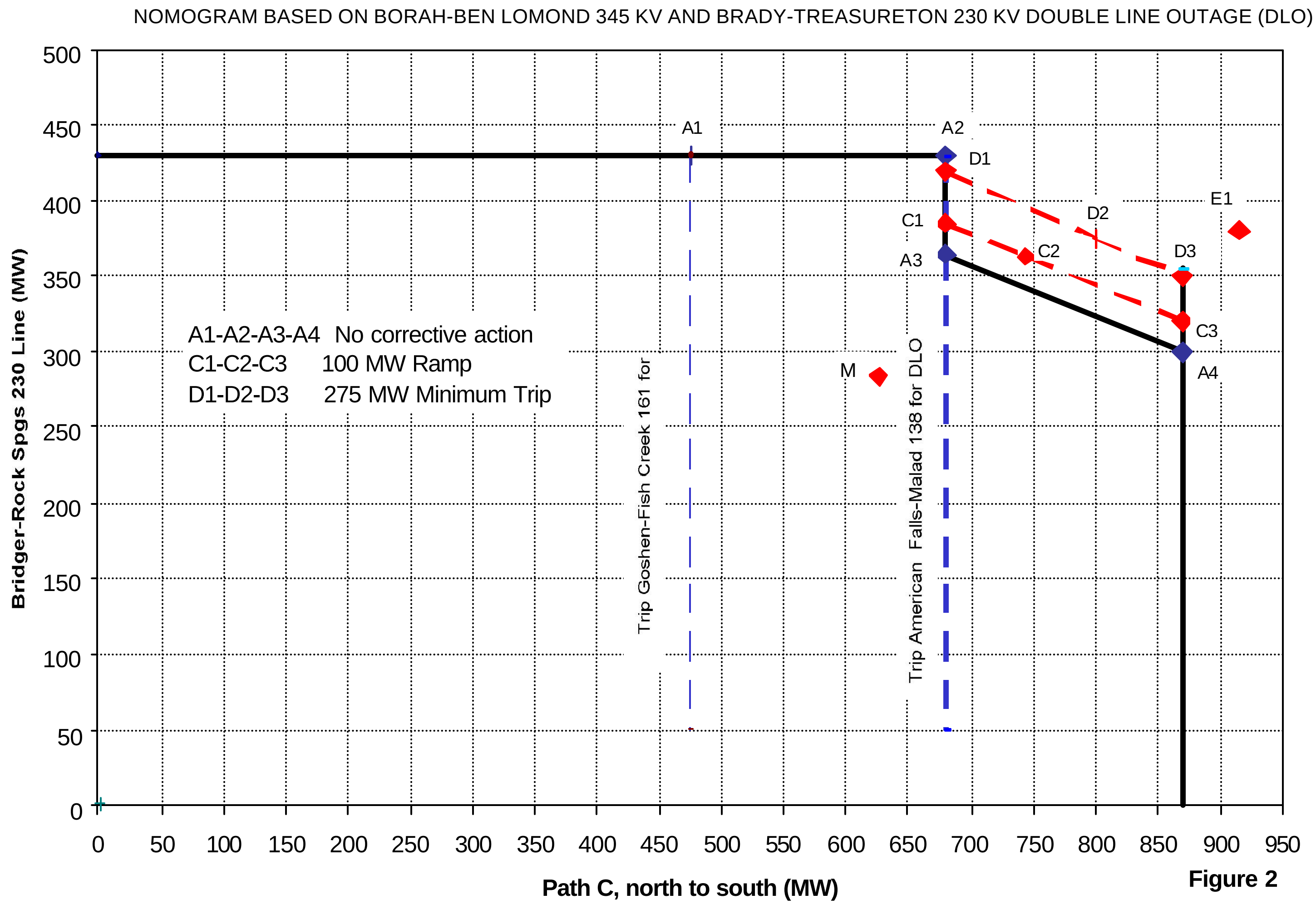


Figure 2

Transmission Nomograms, cont'd.

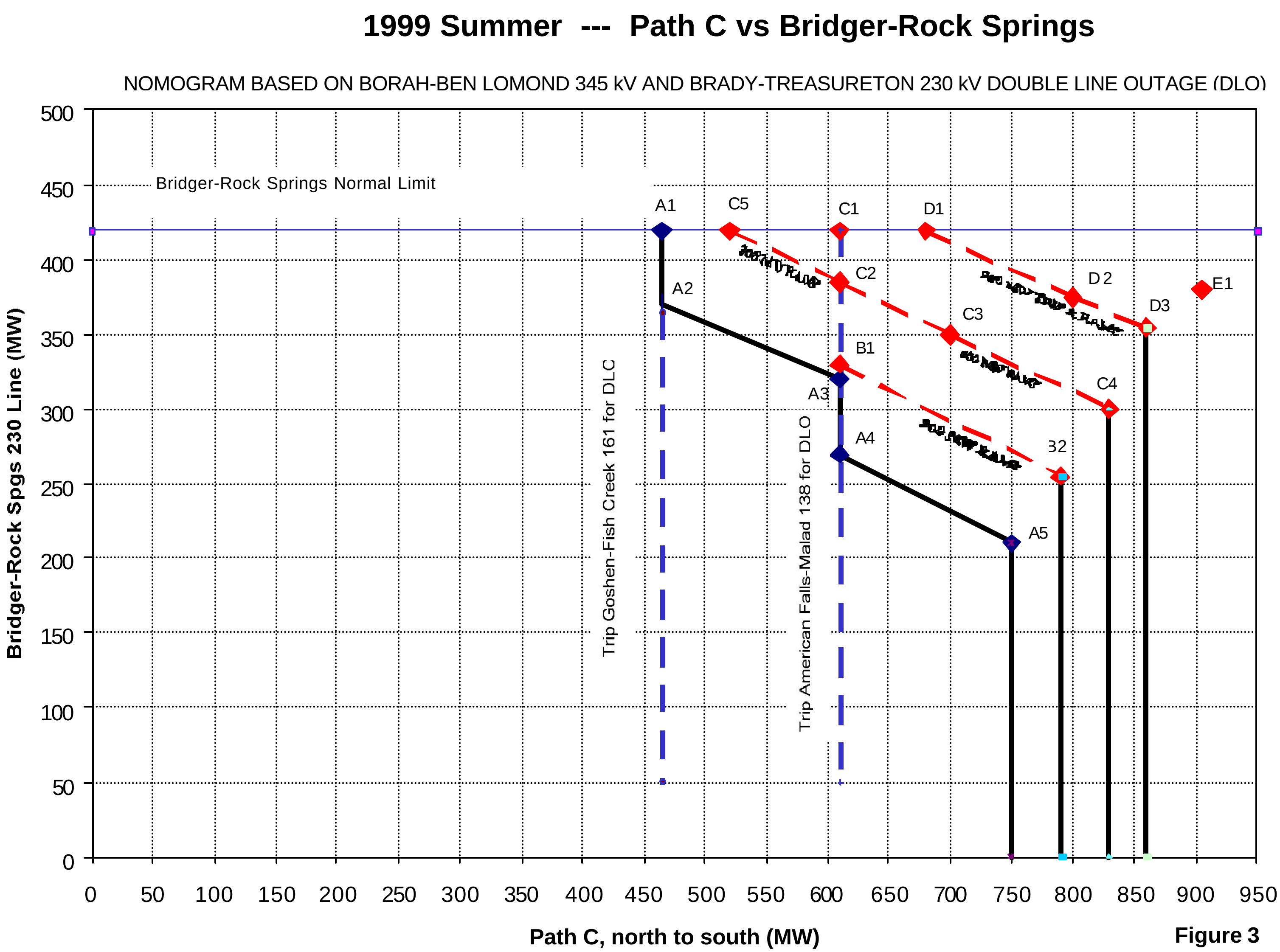
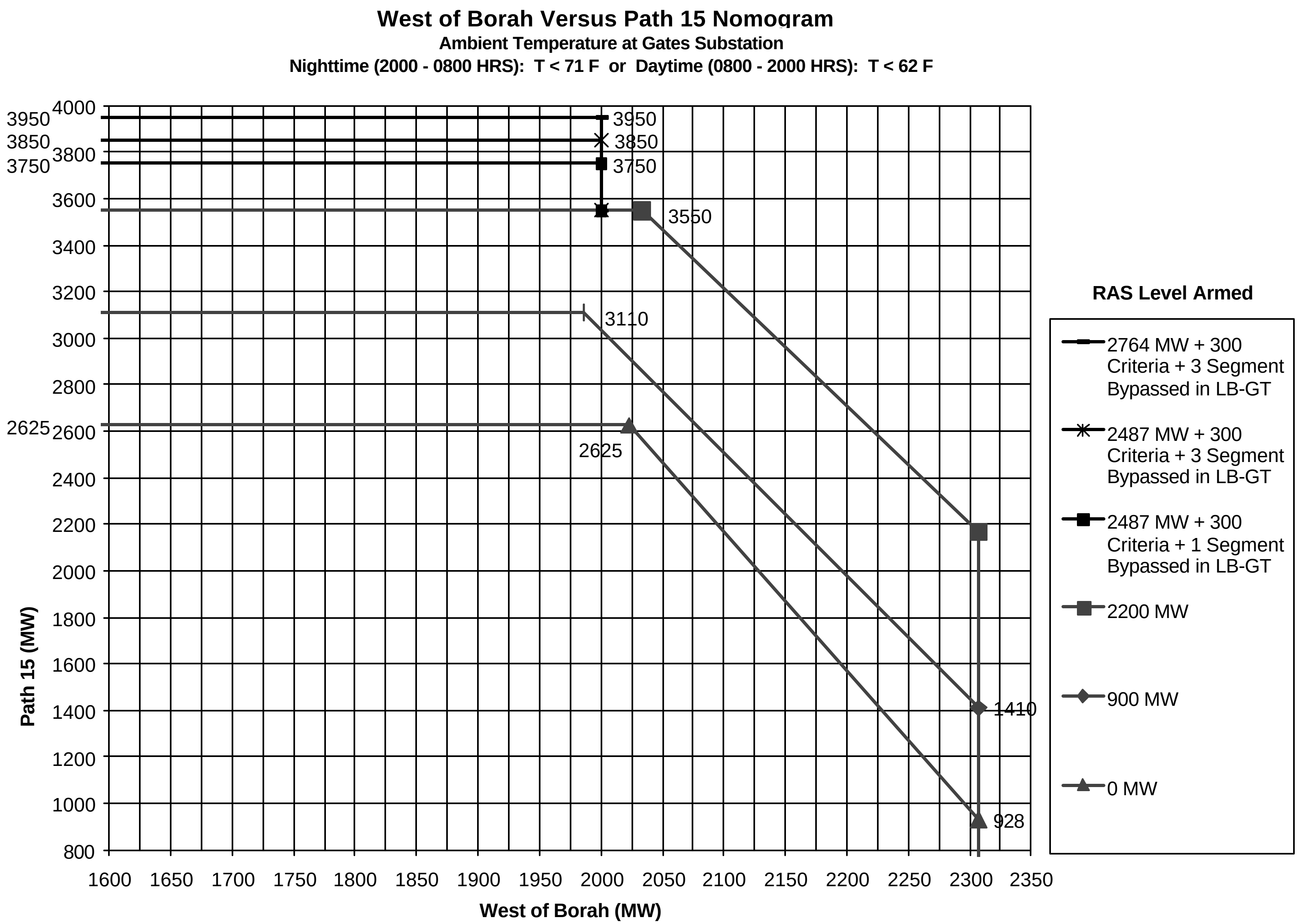


Figure 3

Transmission Nomograms, cont'd.



Appendix 6

Monthly Hydro Generation by Load Area (GWh)

Region	Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	Alberta Power	140	119	110	141	119	164	215	124	101	112	155	143
CA ISO	LA Dept of Water & Power	42	23	63	63	35	28	52	50	65	30	23	11
CA ISO	Pacific Gas & Electric	1,925	2,166	2,696	2,768	2,991	2,862	2,692	2,388	1,813	1,512	1,324	1,661
CA ISO	Southern California Edison	297	296	471	511	574	534	537	455	377	261	195	296
Rocky Mtn	Public Service of Colorado	66	55	70	94	96	140	162	105	76	86	70	74
Rocky Mtn	WAPA Colorado-Missouri	186	166	200	231	356	393	388	328	236	173	182	203
RTO-West	Avista Corp	334	272	314	410	633	706	519	256	184	174	224	337
RTO-West	BC Hydro + W Kootenay	4,907	4,401	4,360	3,608	3,181	3,287	4,161	4,916	4,360	4,384	4,791	5,026
RTO-West	Bonneville Power Admin	8,085	6,940	7,040	7,481	8,552	7,670	6,647	6,552	5,778	4,267	5,529	6,671
RTO-West	Chelan Douglas Grant PUD	1,777	1,452	1,613	2,194	2,667	2,245	1,762	1,652	1,423	1,003	1,431	1,417
RTO-West	Idaho Power Company	756	787	846	882	1,124	796	905	825	751	525	433	552
RTO-West	Montana Power Company	321	258	256	266	328	322	331	317	229	237	270	289
RTO-West	Pacificorp West	378	319	306	346	322	333	269	237	218	208	322	484
RTO-West	Portland General Electric	264	225	251	233	214	168	151	142	142	159	217	249
RTO-West	Puget Sound Energy	125	118	102	93	138	132	117	88	71	118	127	120
RTO-West	Seattle City Light	770	675	749	893	1,107	1,182	984	611	548	483	609	840
W Connect	El Paso Electric	9	8	12	13	12	12	13	11	12	11	8	10
W Connect	Salt River Project	3	5	6	-	3	4	8	4	1	(5)	(4)	(1)
W Connect	WAPA Lower Colorado	626	623	753	819	816	845	878	866	683	582	560	671

Attachment 2: Fuel Price Assumptions

MEMORANDUM

TO: RTO West
FROM: Alex Rudkevich; TCA
CC: Assef Zobian, Ellen Wolfe; TCA
RE: Fuel Price Projections for the WSCC Region
DATE: September 21, 2002

Fuel categories

This memo deals with prices for natural gas, distillate (#2) and residual (#6) fuel oil.

Geographical markets

The forecast covers the entire Mountain and Pacific regions of the 48 states and Canadian provinces of Alberta and British Columbia.

Basis forecasts

The key underlying forecasts are projected prices for crude oil (WTI) and for natural gas (Henry Hub). All other forecasts are derived from these two basic forecasts using projected and/or historical basis differentials as explained later in this memo.

Figure 1 presents TCA's proposed base case forecast of crude oil prices in comparison with historical prices, NYMEX futures prices for the light sweet crude oil (as of September 21, 2001) and a long-term forecast for crude oil prices from EIA's Annual Energy Outlook–2001. As one can see, our proposed forecast is a composition of futures prices in the short term (2001–2003) and EIA's forecast in the long term (2004–2020). It is important to note that the futures prices and the EIA forecast for 2004 are very close.

Similarly, Figure 2 presents TCA's proposed forecast for the spot price of natural gas at Henry Hub. The forecast is shown in comparison with average NYMEX futures prices (as of September 21, 2001) and a long-term forecast per EIA's Annual Energy Outlook–2000.[70] Our proposed forecast is a composition of futures prices in the short term (2001–2003), EIA's long-term forecast in the long term (2005–2020) and a midpoint for these two projections for 2004. Although the resulting forecast for 2004 appears slightly higher than the EIA forecast, the numbers are relatively close. In other words, by that period we observe the convergence between the market outlook (futures prices) and the long-term outlook developed by the EIA.

[70] AEO-2001 does not forecast Henry Hub prices, instead it predicts prices at the wellhead. To come up with the Henry Hub price forecast, we use a historical basis differential of $0.17/Mmbtu.

Figure 1. Crude Oil Prices: History and Projections (2000$/BBL)

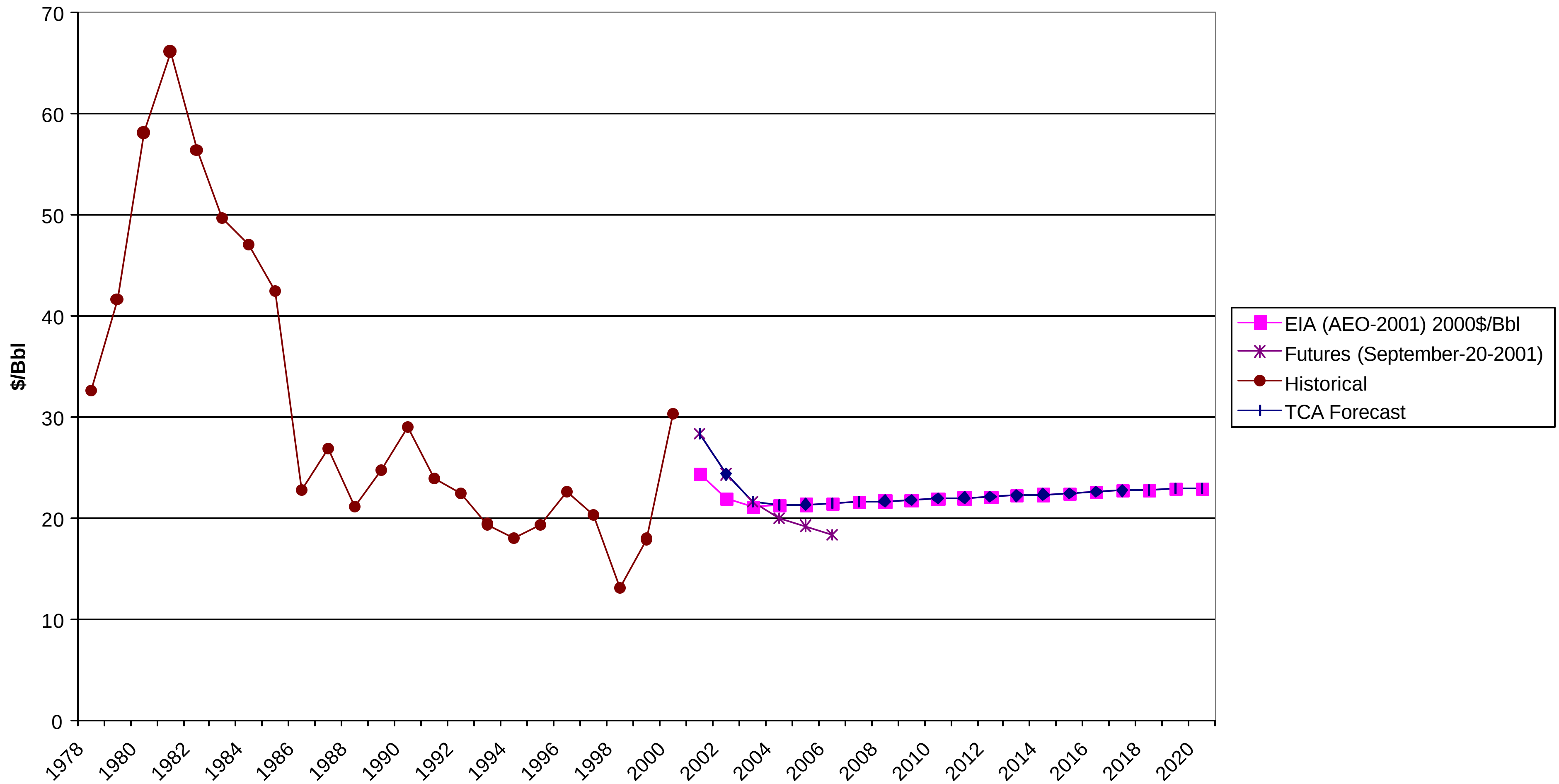
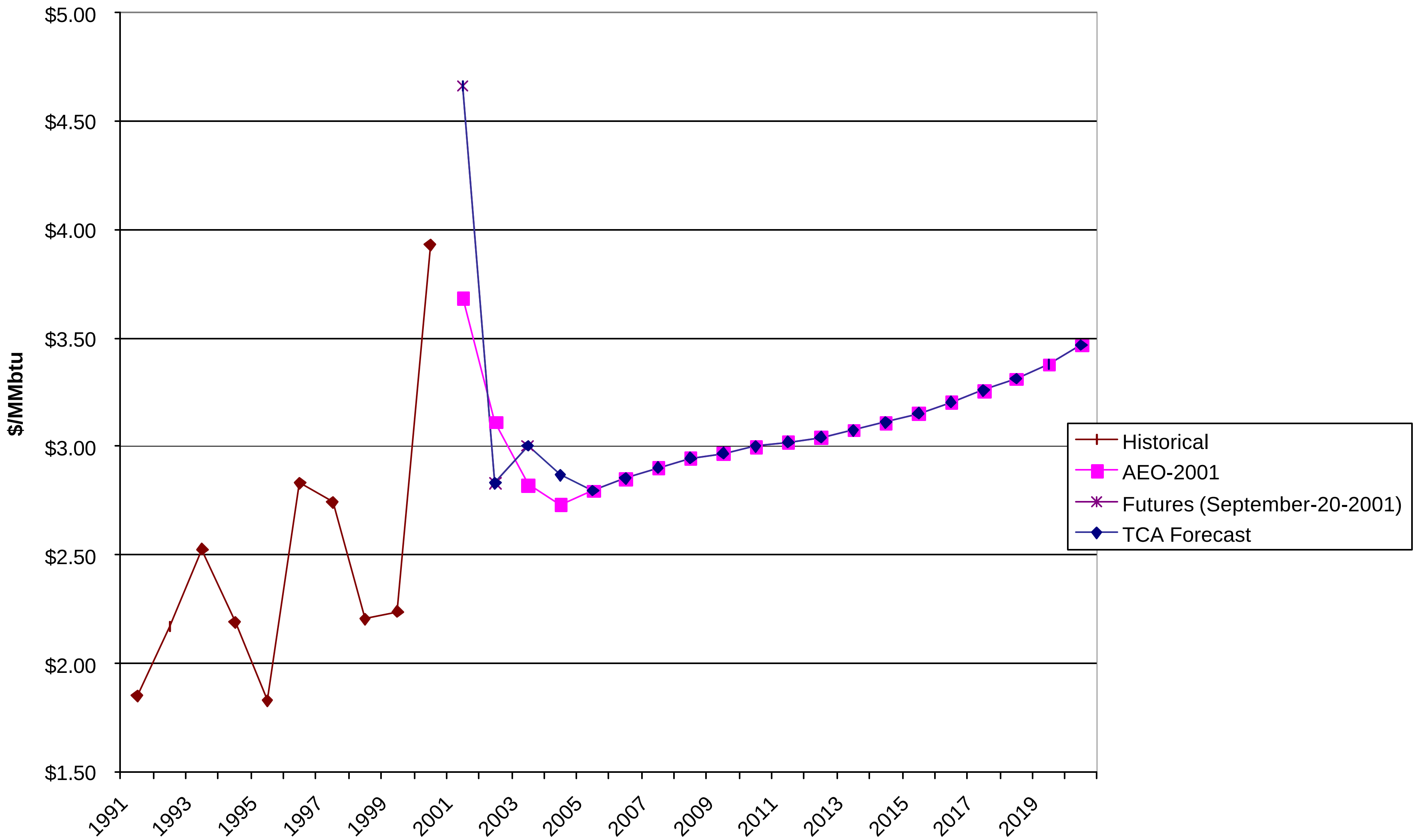


Figure 2. Natural Gas Spot Prices at Henry Hub: History and Projections (2000$/MMbtu)



Generation Fuel Prices

Generation fuel prices are derived from basis forecasts.

Fuel oil prices—methodology

To derive fuel oil prices for electric generation, we use an in-house linear regression model linking crude oil prices with # 6 and # 2 fuel oil in the Northeastern U.S. (New York Harbor). For petroleum prices in other regions, we use state-specific basis differentials using EIA Form 423 data for 1997–2000 and historical spot prices for # 2 and # 6 fuel oil at New York Harbor. We assume a modest seasonal pattern for # 2 fuel oil prices, the same in all regions. Prices for #6 fuel oil are assumed flat.

Natural gas prices – methodology

We develop natural gas projections for the following regions:

- Northern California
- Southern California
- Northern Nevada
- Southern Nevada
- Colorado
- Oregon–Washington
- Utah
- New Mexico–Arizona–Texas (El Paso only)
- Idaho–Montana–Wyoming
- British Columbia
- Alberta

The burner-tip price for natural gas is a sum of two components—regional price and local delivery price.

Local delivery price is differentiated by the electric utility control area. This differentiation is applied *to existing plants only*[71]. Thus estimated deliverability burner-tip component for existing plants is assumed to be effective for year 2000 only. For outer years we let this adder slide linearly to the level of $0.20/MMBtu by the year 2011. However, if this adder is less than $0.20/MMBtu, it remains flat at that level for the entire

[71] TCA conducted an extensive analysis of actual burner-tip costs for the historical period 1998-2000. We analyzed fuel costs on a plant-by-plant basis vis-à-vis regional historical spot prices of natural gas. This plant-by-plant analysis yields unstable results. We believe that this is because generation owners make their fuel purchasing decisions not on a unit-by-unit basis but rather on a system basis. As a results, fuel costs reported by plant often reflect accounting decisions rather than actual economics of fuel supply. In order to smooth this effect, it is more reasonable to conduct this analysis on a company basis. For modeling convenience given the current structure of information in TCA GE MAPS database, we used the notion of control area as a proxy for the generation operator.

forecast period. This linear decline reflects our assumption that generating companies would renegotiate their contract with natural gas suppliers such that prices should be closer to spot prices than they currently appear. The remaining $0.20/MMBtu adder should reflect unavoidable LDC and/or lateral charge. (This is our "best-guess estimate.") For new gas-fired plants, the local component is set at $0.07/MMBtu to reflect pipeline lateral charges. (This is our "best-guess" estimate.)

Following is a table of estimated deliverability charges for existing plants by state and control area. The additional charge is from the nearest Hub.

State/Control area	Charge ($/MMBtu)		State/Control area	Charge ($/MMBtu)	
	2000	2004		2000	2004
AZ AEPCO	0.35	0.29	CO CSW	0.67	0.50
AZ APS	0.59	0.45	CO PSCo	0.85	0.62
AZ IID	0.56	0.43	CO NUGs	0.66	0.49
AZ SRP	0.74	0.54	CO Other	0.34	0.29
AZ TEP	0.96	0.68			
AZ Other	0.55	0.43	ID WWPC	0.56	0.43
CA CAMXNGCO	0.41	0.33	NM EPE	0.11	0.11
CA LDWP	0.86	0.62	NM PNM	0.45	0.36
CA NCMID	0.42	0.34	NM Other	0.24	0.23
CA PG&E	0.52	0.40			
CA SCE	0.62	0.47	NV NEVP	0.56	0.43
CA IID	0.70	0.39	NV SPP	0.11	0.11
CA SMUD	0.21	0.21	NV Other	0.34	0.29
CA SDGE	0.51	0.39			
CA Other	0.54	0.30	OR PGE	0.14	0.14
			OR Other	0.11	0.11
TX EPE	0.45	0.36			
			WA PSPL	0.45	0.36
UT PAC	0.53	0.41	WA WWPC	0.45	0.36
UT Other	0.35	0.29	WA NUGs	0.45	0.36
			WA Other	0.45	0.36
WY	0.40	0.33			

Forecast regional gas prices are derived from the Henry Hub forecast using TCA in-house regression models calibrated on historical regional prices vs. prices at Henry Hub. The relevant price point by region are identified below:

No.	Region	Henry Hub Prices Regressed to:
1	Northern CA	PG&E Citygates (Jan 98 through Apr 2001)
2	Southern CA	Southern CA Border (Jan 98 through Apr 2001)
3	Southern Nevada	Kern River (Jan 98 through Apr 2001)
4	Northern Nevada	Average of NPL Prices for Domestic and Stanfield points (Jan 98 through Apr 2001)
4	Colorado	Average of CIG (N.Syst) and DJ Basin prices (Jan 98 through Apr 2001)
5	Oregon–Washington	Average of PGT (Kingsgate) and Northwest Stanfield prices (Jan 98 through Apr 2001)
6	Utah	Average of Kern River and Questar prices (Jan 98 through Apr 2001)
7	New Mexico–Arizona–Texas (El Paso)	San Juan Basin prices (Jan 98 through Apr 2001)
8	Idaho–Montana–Wyoming	CIG (N.Syst) prices (Jan 98 through Apr 2001)
9	British Columbia	PGT Kingsgate prices (Jan 98 through Apr 2001)
10	Alberta	NOVA (AECO-C) prices (Jan 98 through Apr 2001)

Seasonal patterns are developed in the following manner.

- For Henry Hub, we estimate historical seasonal pattern based on 1998–2000 actual monthly prices.
- Regional seasonal patterns appear automatically by applying the regression model to the monthly Henry Hub forecast.

Figures 3–12 present comparisons of monthly generation fuel prices for the period 2001–2010. Figures 13A and 13B provide a comparison of regional natural gas prices. Please note that on these figures we show burner-tip natural gas prices applicable for the new generating projects (with local component equal to $0.07/MMBtu).

Figure 3. Fuel Price Forecast: N. California

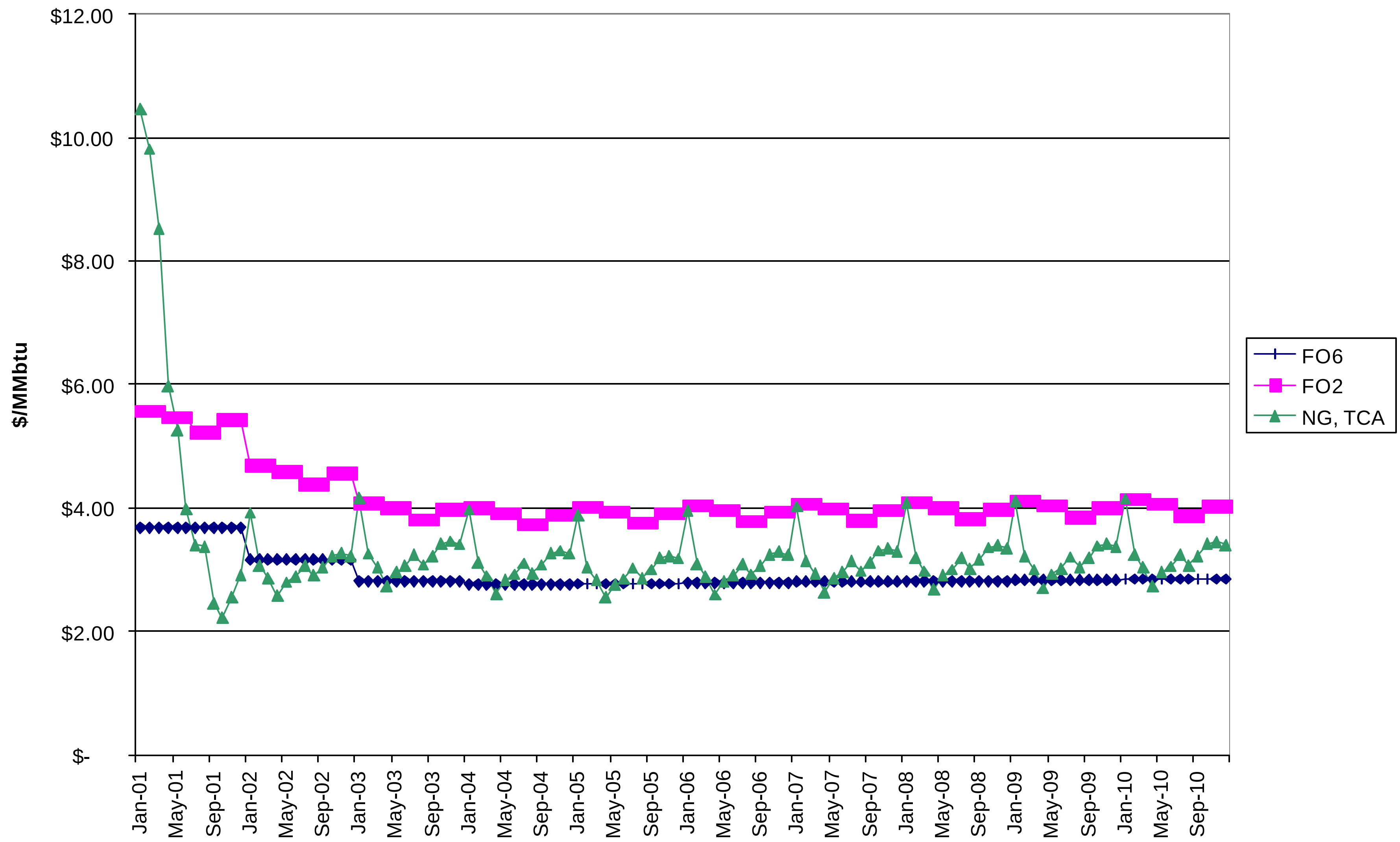


Figure 4. Fuel Price Forecast: S. California

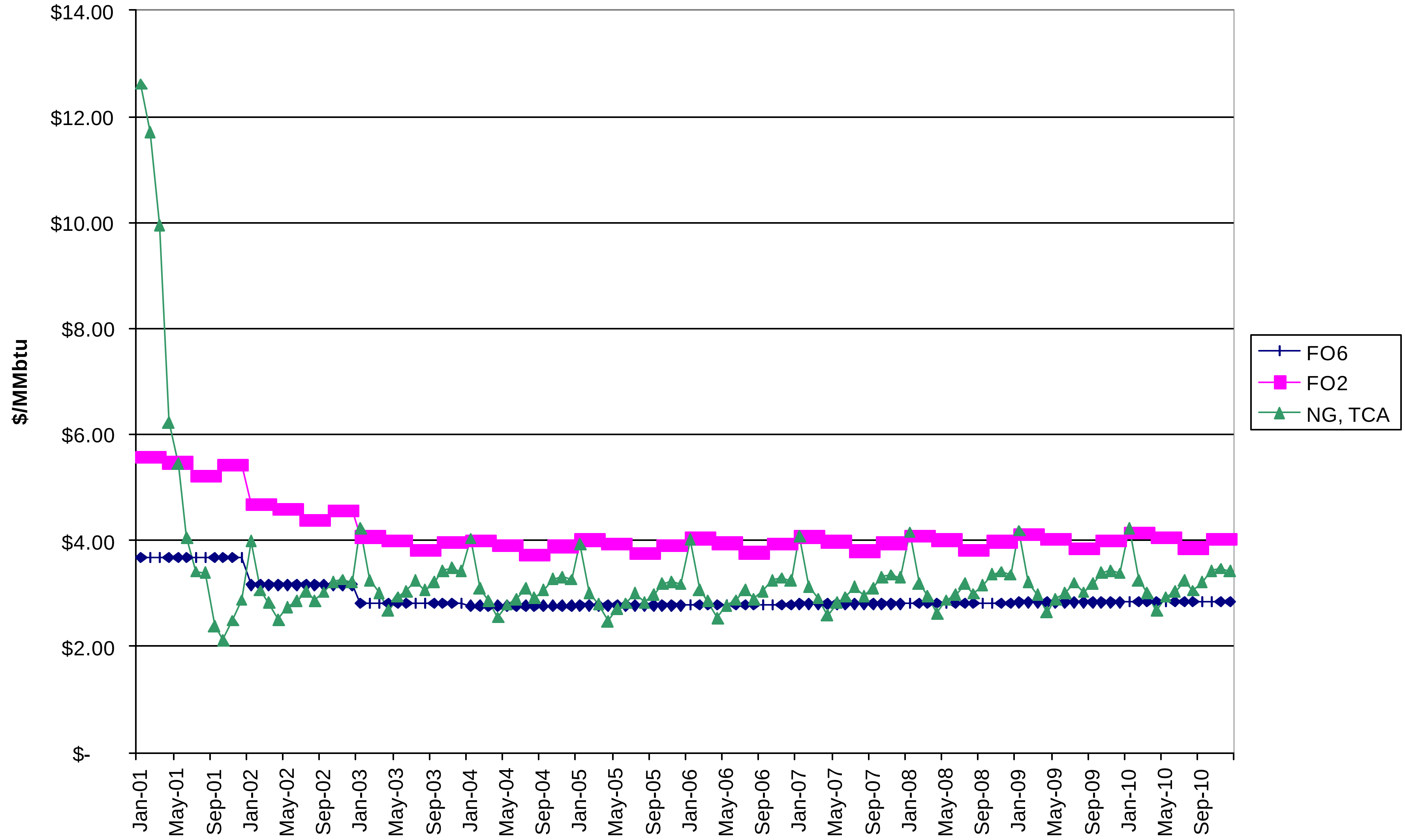


Figure 5. Fuel Price Forecast: Nevada

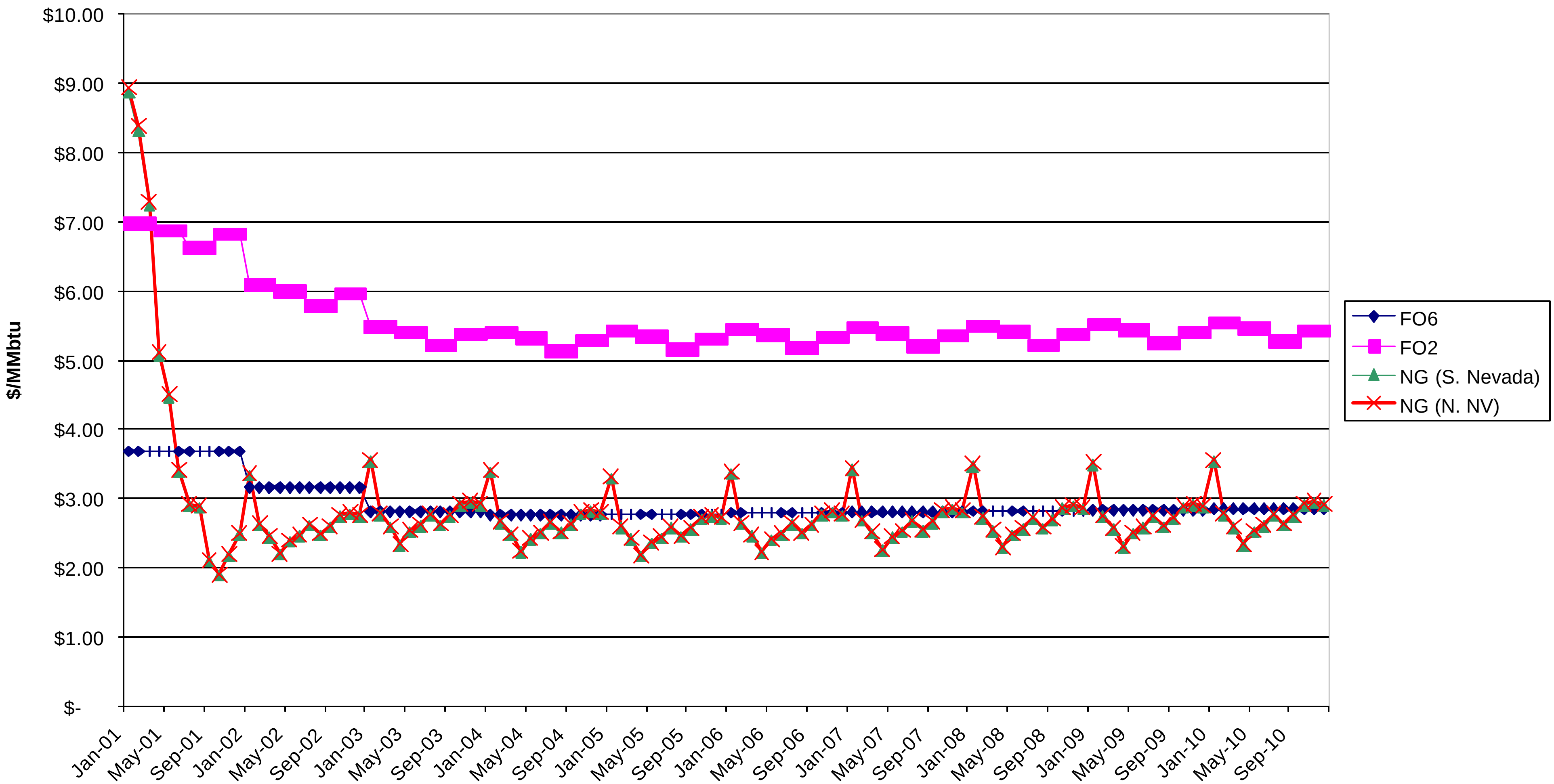


Figure 6. Fuel Price Forecast: Colorado

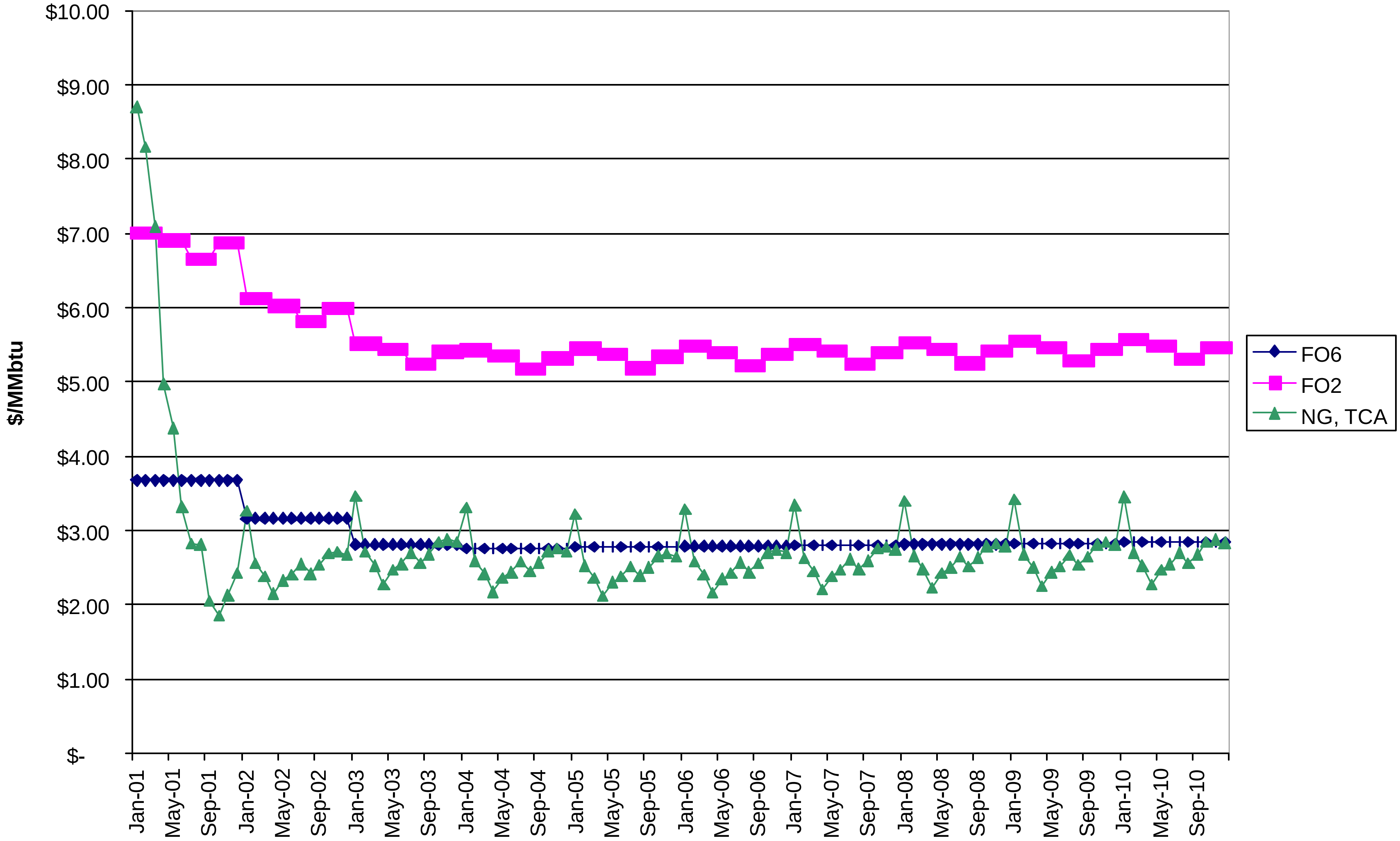


Figure 7. Fuel Price Forecast: Oregon-Washington

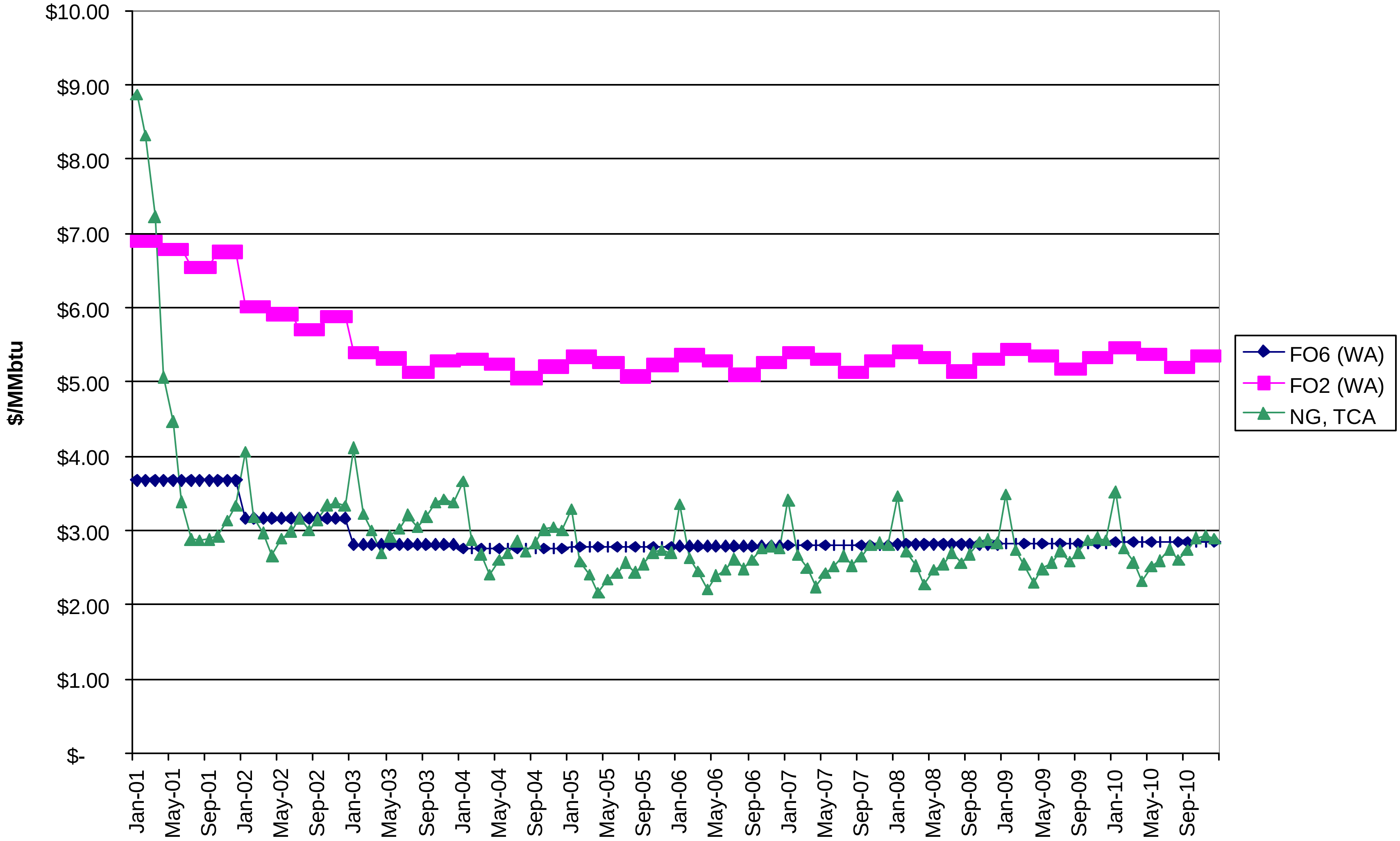


Figure 8. Fuel Price Forecast: Utah

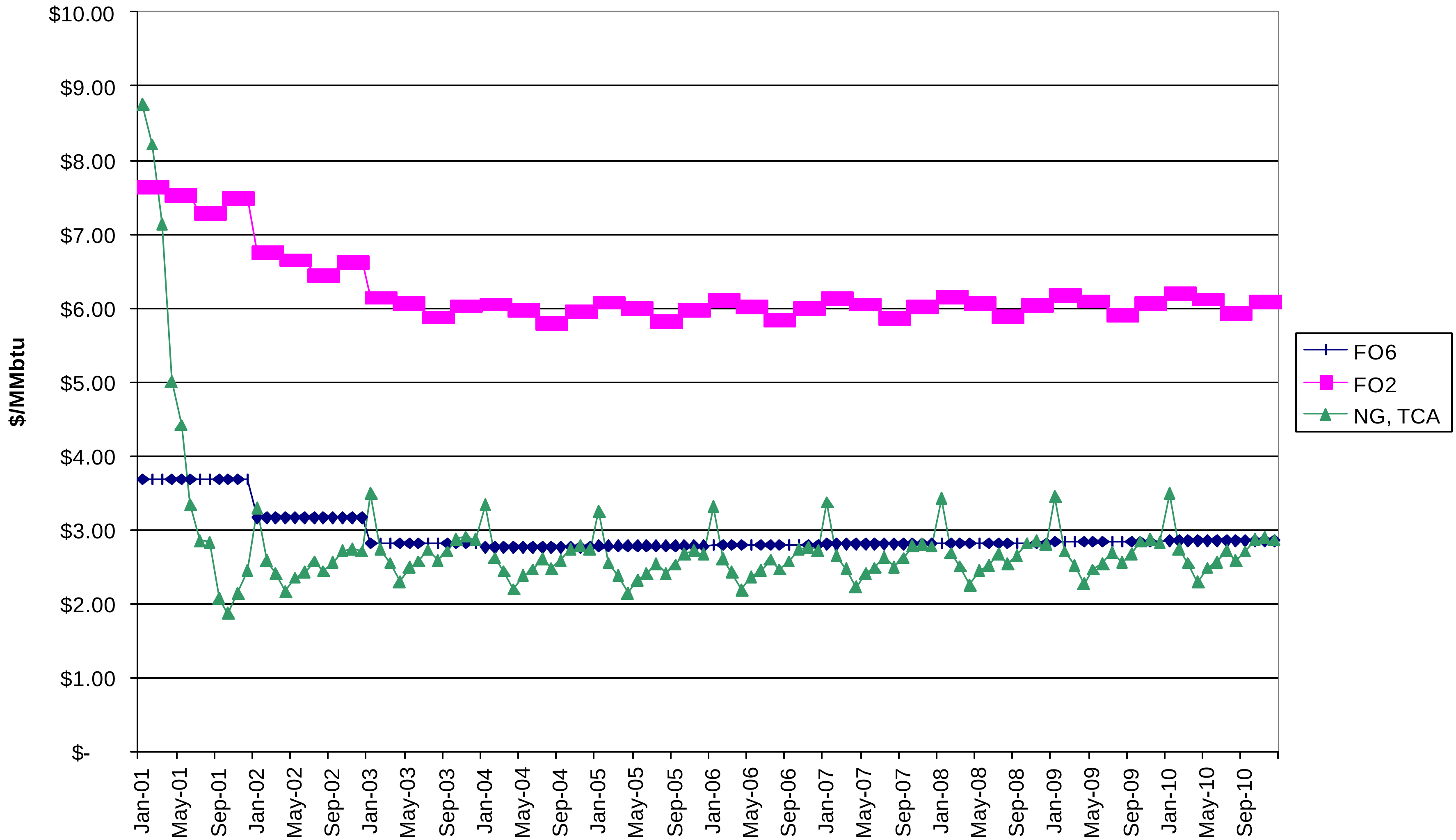


Figure 9. Fuel Price Forecast: New Mexico-Arizona

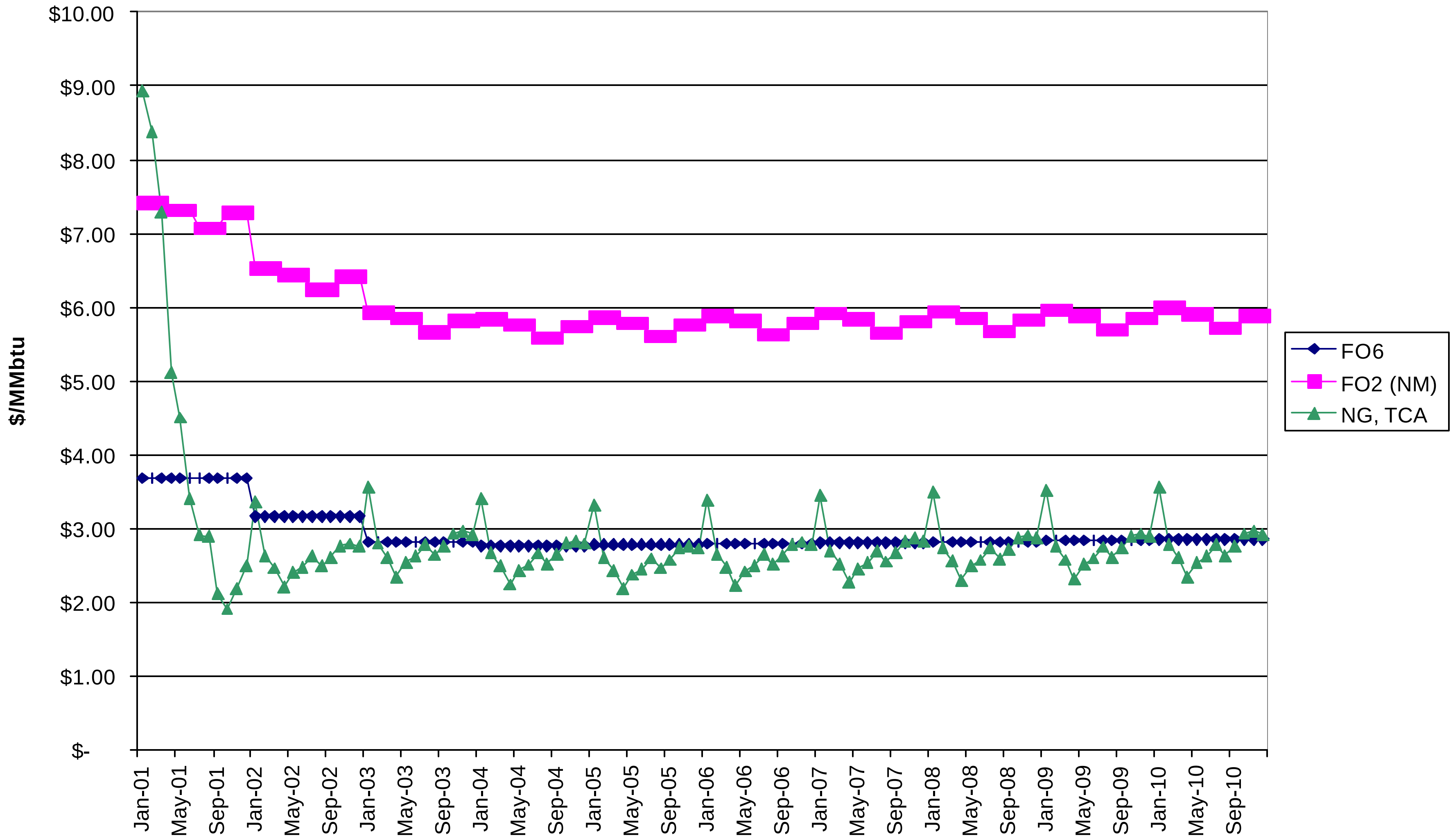


Figure 10. Fuel Price Forecast: Idaho-Montana-Wyoming

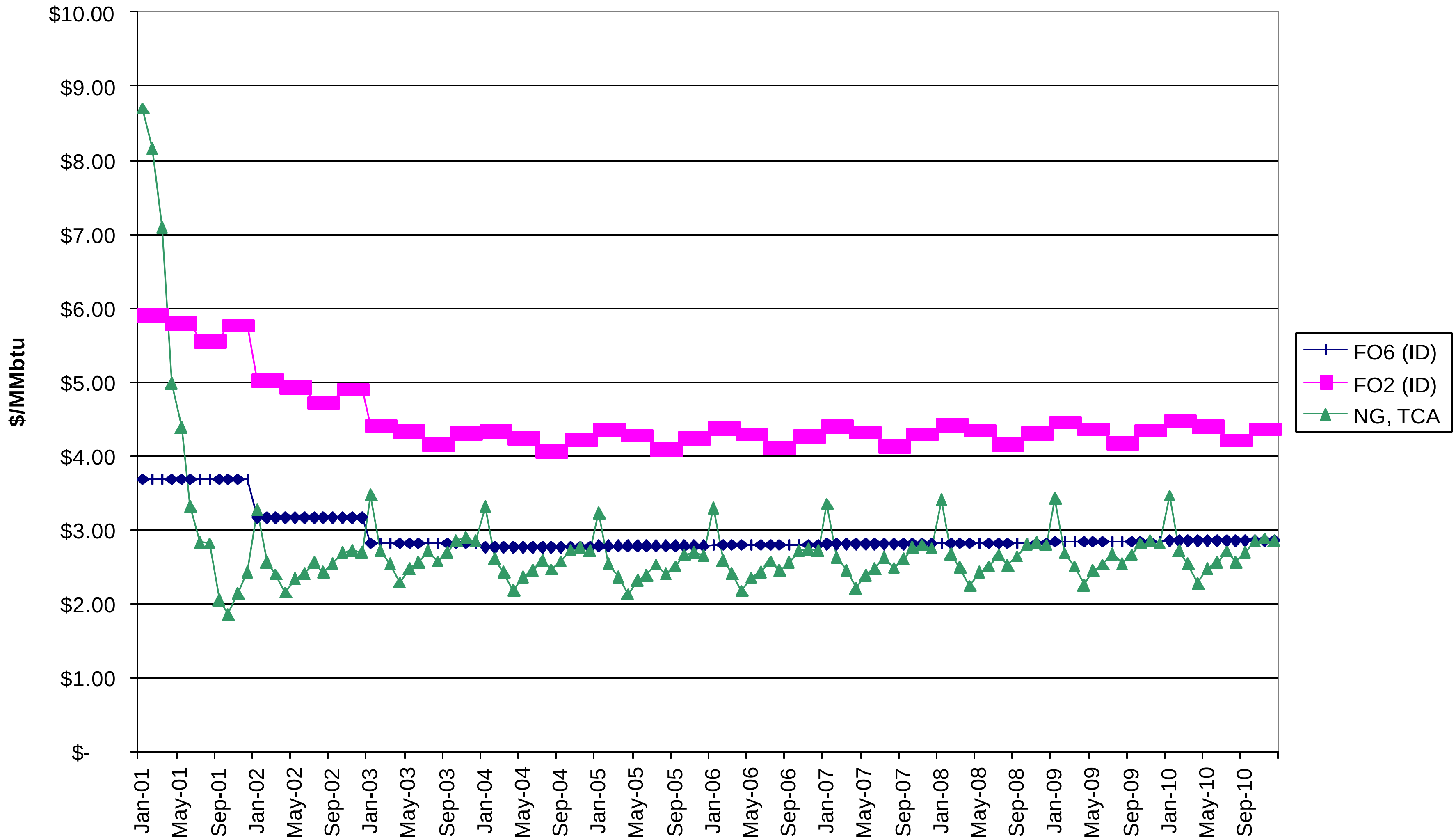


Figure 11. Fuel Price Forecast: British Columbia

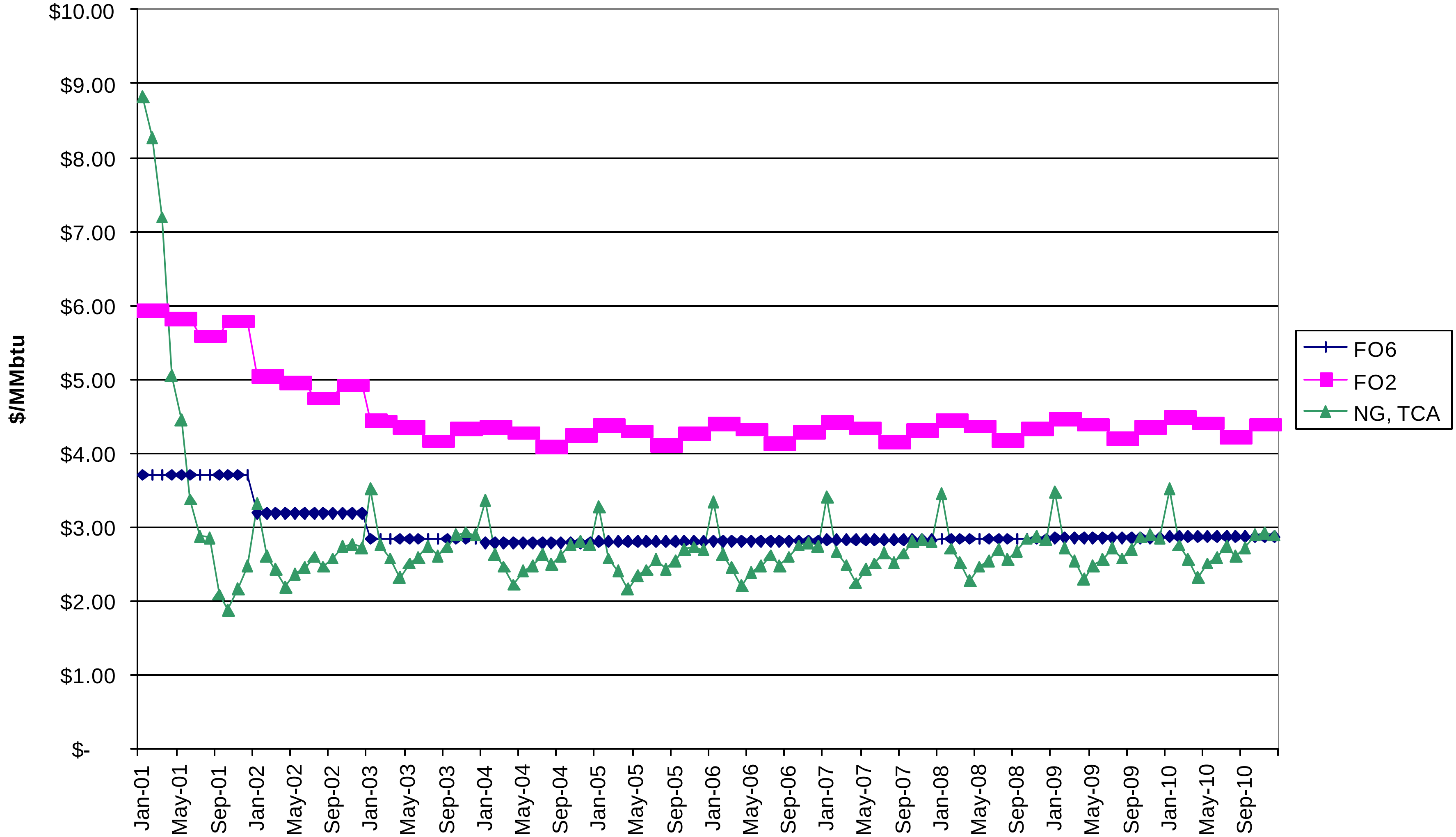


Figure 12. Fuel Price Forecast: Alberta

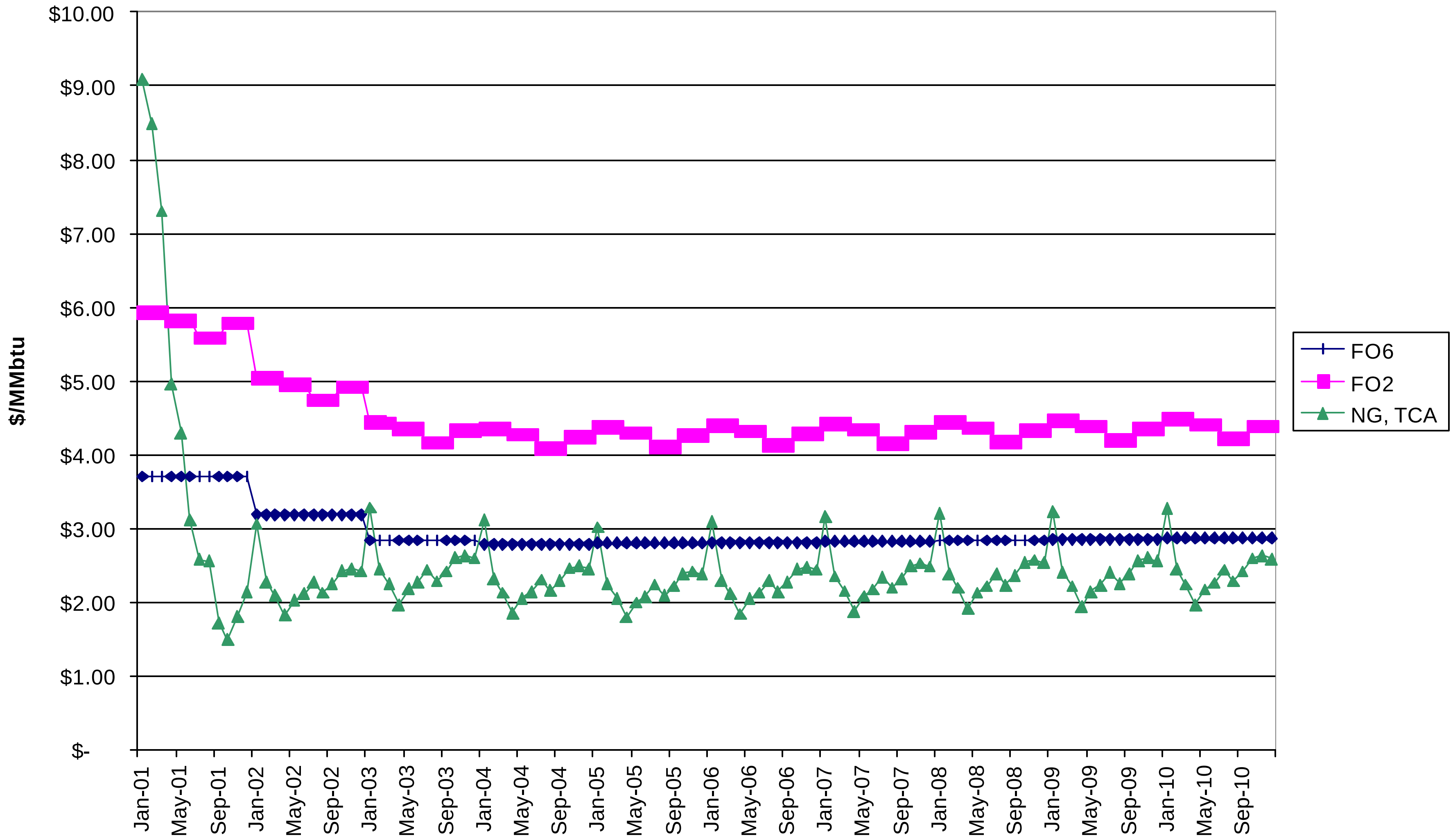


Figure 13A. Comparison of Regional Monthly Natural Gas Prices (2001-2010)

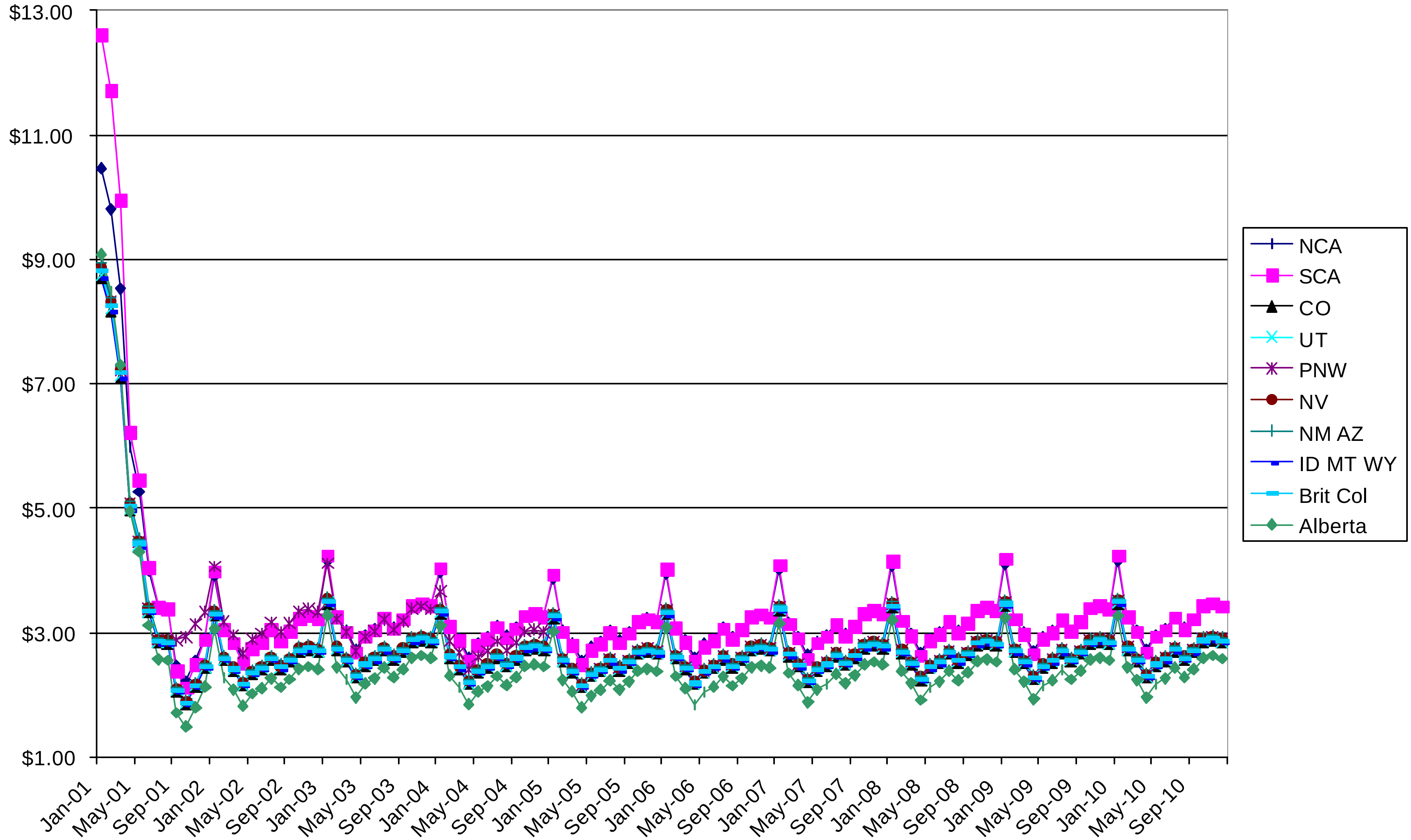
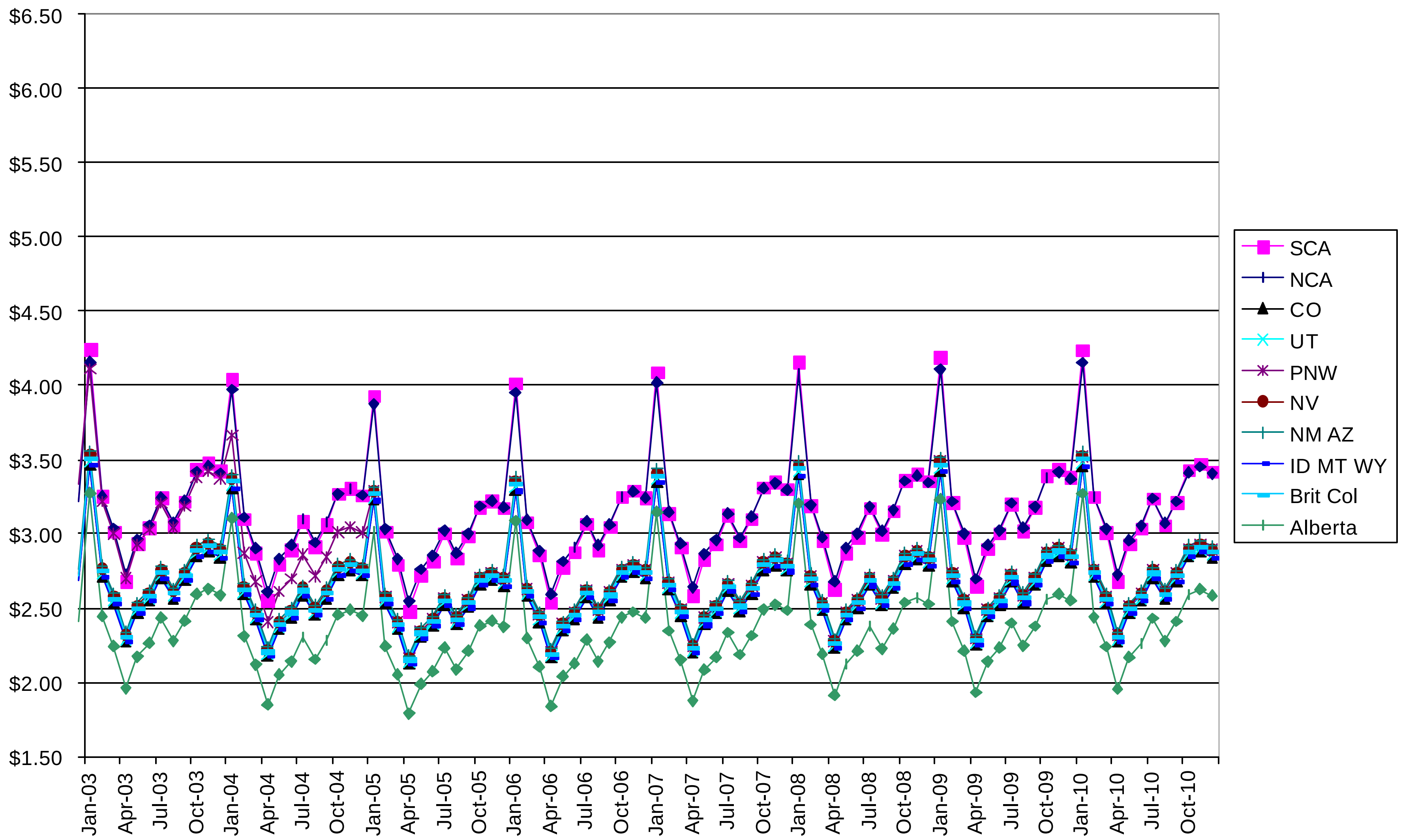


Figure 13B. Comparison of Regional Monthly Natural Gas Prices (2003-2010)



Attachment 3: Sensitivity Results: Annual Average Locational Energy Price Tables

Table 30: Annual Average Energy Price (Real 2000$/MWh) :
Short Supply Case (Low Water/High Gas Price)

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	42.53	41.55	(2.31)
Avista Corp	RTO-West	40.21	35.81	(10.94)
Bonneville Power Admin	RTO-West	39.60	35.71	(9.83)
Chelan Douglas Grant PUD	RTO-West	39.08	35.67	(8.73)
Idaho Power Company	RTO-West	34.98	34.38	(1.73)
Montana Power Company	RTO-West	34.10	32.73	(4.03)
Nevada Power Company	RTO-West	36.99	34.57	(6.55)
Pacificorp East	RTO-West	34.91	31.98	(8.37)
Pacificorp West	RTO-West	36.82	35.55	(3.43)
Portland General Electric	RTO-West	37.20	35.64	(4.20)
Puget Sound Energy	RTO-West	40.36	35.68	(11.60)
Seattle City Light	RTO-West	39.61	35.66	(9.97)
Sierra Pacific Power	RTO-West	44.58	39.45	(11.50)
Tacoma Public Utilities	RTO-West	39.19	35.67	(8.98)
Alberta Power	ALBERTA	27.53	26.70	(3.02)
LA Dept of Water & Power	CA ISO	38.59	35.08	(9.09)
Pacific Gas & Electric	CA ISO	38.71	35.43	(8.48)
San Diego Gas & Electric	CA ISO	37.79	34.89	(7.67)
Southern California Edison	CA ISO	38.50	35.27	(8.39)
Public Service of Colora	Rocky Mtn	40.06	30.03	(25.05)
WAPA Colorado-Missouri	Rocky Mtn	34.25	30.08	(12.18)
WAPA Upper Missouri	Rocky Mtn	38.69	30.01	(22.43)
Arizona Public Service	WConnect	36.76	31.77	(13.57)
El Paso Electric	WConnect	41.27	34.20	(17.11)
Imperial Irrigation Dist	WConnect	36.22	32.52	(10.23)
Public Service New Mexico	WConnect	37.08	31.66	(14.60)
Salt River Project	WConnect	36.70	31.68	(13.69)
Tucson Electric Power	WConnect	36.44	31.40	(13.83)
WAPA Lower Colorado	WConnect	36.76	31.47	(14.39)

Table 31: Annual Average Energy Price (Real 2000$/MWh): Transmission Line Losses Fixed as in Without RTO

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	35.80	34.67	(3.15)
Avista Corp	RTO-West	35.50	31.14	(12.29)
Bonneville Power Admin	RTO-West	34.82	30.30	(12.98)
Chelan Douglas Grant PUD	RTO-West	34.18	29.88	(12.56)
Idaho Power Company	RTO-West	30.30	28.38	(6.36)
Montana Power Company	RTO-West	25.24	25.07	(0.69)
Nevada Power Company	RTO-West	33.75	29.88	(11.48)
Pacificorp East	RTO-West	30.16	26.59	(11.85)
Pacificorp West	RTO-West	32.73	28.91	(11.68)
Portland General Electric	RTO-West	33.42	29.47	(11.81)
Puget Sound Energy	RTO-West	35.60	31.25	(12.21)
Seattle City Light	RTO-West	34.82	30.47	(12.48)
Sierra Pacific Power	RTO-West	40.99	33.40	(18.52)
Tacoma Public Utilities	RTO-West	34.42	30.07	(12.65)
Alberta Power	ALBERTA	23.98	23.14	(3.49)
LA Dept of Water & Power	CA ISO	34.39	30.72	(10.67)
Pacific Gas & Electric	CA ISO	32.88	31.05	(5.58)
San Diego Gas & Electric	CA ISO	32.20	30.68	(4.74)
Southern California Edison	CA ISO	32.93	31.15	(5.41)
Public Service of Colora	Rocky Mtn	32.66	26.75	(18.11)
WAPA Colorado-Missouri	Rocky Mtn	26.75	24.79	(7.34)
WAPA Upper Missouri	Rocky Mtn	27.59	24.53	(11.09)
Arizona Public Service	WConnect	31.17	28.35	(9.05)
El Paso Electric	WConnect	36.17	31.31	(13.44)
Imperial Irrigation Dist	WConnect	30.69	28.06	(8.58)
Public Service New Mexico	WConnect	33.16	28.53	(13.94)
Salt River Project	WConnect	31.12	28.27	(9.18)
Tucson Electric Power	WConnect	31.14	27.99	(10.10)
WAPA Lower Colorado	WConnect	31.11	27.94	(10.19)

Table 32: Annual Average Energy Price (Real 2000$/MWh): Scheduling Limits Fixed as in Without RTO

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	35.80	34.41	(3.89)
Avista Corp	RTO-West	35.50	29.70	(16.34)
Bonneville Power Admin	RTO-West	34.82	29.75	(14.57)
Chelan Douglas Grant PUD	RTO-West	34.18	29.73	(13.01)
Idaho Power Company	RTO-West	30.30	28.93	(4.53)
Montana Power Company	RTO-West	25.24	26.82	6.27
Nevada Power Company	RTO-West	33.75	30.38	(9.99)
Pacificorp East	RTO-West	30.16	27.46	(8.94)
Pacificorp West	RTO-West	32.73	29.68	(9.33)
Portland General Electric	RTO-West	33.42	29.73	(11.05)
Puget Sound Energy	RTO-West	35.60	29.77	(16.39)
Seattle City Light	RTO-West	34.82	29.75	(14.56)
Sierra Pacific Power	RTO-West	40.99	33.21	(18.97)
Tacoma Public Utilities	RTO-West	34.42	29.75	(13.56)
Alberta Power	ALBERTA	23.98	23.81	(0.69)
LA Dept of Water & Power	CA ISO	34.39	30.99	(9.87)
Pacific Gas & Electric	CA ISO	32.88	31.32	(4.76)
San Diego Gas & Electric	CA ISO	32.20	30.97	(3.83)
Southern California Edison	CA ISO	32.93	31.41	(4.61)
Public Service of Colora	Rocky Mtn	32.66	25.72	(21.23)
WAPA Colorado-Missouri	Rocky Mtn	26.75	25.76	(3.73)
WAPA Upper Missouri	Rocky Mtn	27.59	24.56	(10.99)
Arizona Public Service	WConnect	31.17	27.77	(10.93)
El Paso Electric	WConnect	36.17	30.63	(15.32)
Imperial Irrigation Dist	WConnect	30.69	28.71	(6.44)
Public Service New Mexico	WConnect	33.16	27.80	(16.14)
Salt River Project	WConnect	31.12	27.68	(11.06)
Tucson Electric Power	WConnect	31.14	27.41	(11.96)
WAPA Lower Colorado	WConnect	31.11	27.42	(11.85)

Table 33: Annual Average Energy Price (Real 2000$/MWh): Maintenance Schedule Fixed as in Without RTO

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	35.80	34.58	(3.41)
Avista Corp	RTO-West	35.50	30.03	(15.41)
Bonneville Power Admin	RTO-West	34.82	30.06	(13.68)
Chelan Douglas Grant PUD	RTO-West	34.18	30.03	(12.14)
Idaho Power Company	RTO-West	30.30	28.99	(4.33)
Montana Power Company	RTO-West	25.24	27.32	8.23
Nevada Power Company	RTO-West	33.75	30.43	(9.85)
Pacificorp East	RTO-West	30.16	27.42	(9.07)
Pacificorp West	RTO-West	32.73	29.94	(8.53)
Portland General Electric	RTO-West	33.42	30.01	(10.20)
Puget Sound Energy	RTO-West	35.60	30.07	(15.52)
Seattle City Light	RTO-West	34.82	30.05	(13.68)
Sierra Pacific Power	RTO-West	40.99	33.89	(17.33)
Tacoma Public Utilities	RTO-West	34.42	30.06	(12.67)
Alberta Power	ALBERTA	23.98	23.09	(3.70)
LA Dept of Water & Power	CA ISO	34.39	31.04	(9.73)
Pacific Gas & Electric	CA ISO	32.88	31.38	(4.58)
San Diego Gas & Electric	CA ISO	32.20	31.02	(3.67)
Southern California Edison	CA ISO	32.93	31.45	(4.50)
Public Service of Colora	Rocky Mtn	32.66	25.88	(20.75)
WAPA Colorado-Missouri	Rocky Mtn	26.75	25.91	(3.14)
WAPA Upper Missouri	Rocky Mtn	27.59	25.04	(9.26)
Arizona Public Service	WConnect	31.17	27.86	(10.63)
El Paso Electric	WConnect	36.17	30.56	(15.50)
Imperial Irrigation Dist	WConnect	30.69	28.79	(6.20)
Public Service New Mexico	WConnect	33.16	27.80	(16.15)
Salt River Project	WConnect	31.12	27.77	(10.76)
Tucson Electric Power	WConnect	31.14	27.54	(11.56)
WAPA Lower Colorado	WConnect	31.11	27.55	(11.44)

Table 34: Annual Average Energy Price (Real 2000$/MWh): Operating Reserves (non AGC)

Annual Average Energy Price (Real 2000$/MWh)				
Area	Region	Without RTO	With RTO	% Change
BC Hydro + W Kooteny	RTO-West	32.45	32.47	0.05
Avista Corp	RTO-West	32.42	28.90	(10.86)
Bonneville Power Admin	RTO-West	31.77	28.95	(8.85)
Chelan Douglas Grant PUD	RTO-West	31.13	28.94	(7.03)
Idaho Power Company	RTO-West	26.80	28.13	4.96
Montana Power Company	RTO-West	21.78	26.01	19.44
Nevada Power Company	RTO-West	31.17	29.75	(4.57)
Pacificorp East	RTO-West	26.95	26.72	(0.86)
Pacificorp West	RTO-West	29.57	28.89	(2.31)
Portland General Electric	RTO-West	30.28	28.94	(4.43)
Puget Sound Energy	RTO-West	32.57	28.97	(11.04)
Seattle City Light	RTO-West	31.77	28.95	(8.88)
Sierra Pacific Power	RTO-West	36.14	32.31	(10.60)
Tacoma Public Utilities	RTO-West	31.38	28.96	(7.72)
Alberta Power	ALBERTA	20.53	20.37	(0.80)
LA Dept of Water & Power	CA ISO	31.85	30.53	(4.15)
Pacific Gas & Electric	CA ISO	30.73	30.84	0.36
San Diego Gas & Electric	CA ISO	30.08	30.52	1.44
Southern California Edison	CA ISO	30.84	30.95	0.36
Public Service of Colora	Rocky Mtn	28.95	25.23	(12.84)
WAPA Colorado-Missouri	Rocky Mtn	23.02	25.27	9.75
WAPA Upper Missouri	Rocky Mtn	24.18	24.04	(0.61)
Arizona Public Service	WConnect	28.97	27.33	(5.67)
El Paso Electric	WConnect	33.53	29.71	(11.40)
Imperial Irrigation Dist	WConnect	28.57	28.27	(1.07)
Public Service New Mexico	WConnect	30.32	27.20	(10.30)
Salt River Project	WConnect	28.92	27.24	(5.80)
Tucson Electric Power	WConnect	28.87	26.97	(6.56)
WAPA Lower Colorado	WConnect	28.65	26.98	(5.83)

Attachment 4: Exchange Questions

RTO West Benefit/Cost Benchmarking Questions

1. Please provide the name, email address and phone number of the contact person for this survey

2. When did your exchange organize and begin operation?

3. What product(s) is (are) traded via your exchange (i.e. Energy, Reserves, Transmission Rights, etc.)?

4. Do you operate only "primary" exchanges for the direct sale of products, or do you offer secondary market products?

5. What geographic areas or regions does your exchange cover?

6. For the regions noted above, does your exchange operate within or as a single control area? If not, how many control areas are encompassed by your exchange?

7. What is the volume of each product traded on your exchange?

8. What was the initial cost of establishing the exchange(s) operated by your company? (Please state the currency if not reported in $US.) Please provide a breakdown to the extent possible (e.g., software, staffing, real estate, etc.)

9. What is the annual operating cost to maintain the exchange(s)? (Please state the currency if not reported in $US.)

10. If multiple products are traded via your exchange, please separate to the extent possible any of the setup costs according to exchange products.

11. If multiple products are traded via your exchange, please separate to the extent possible any of the ongoing operating costs according to exchange products.

12. Please provide information on cost recovery by addressing the following:
    a. Are exchange charges to customers itemized according to exchange market product? Is there a one-time, annual fee, or infrastructure cost for participating in the exchange?

13. Please provide a brief description of how your exchange interacts with system controllers? Can you characterize/elaborate on the information flow between the exchange and the system controller, including the type of data exchanged, the frequency, and the standards, if any, guiding such an exchange of information?

Attachment 5: SC Survey

Scheduling Coordinator (SC) and Qualified Scheduling Entity (QSE) Benchmarking Survey

1. Please provide the name, email address and phone number of the contact person for this survey.

2. When did your business begin operation?

3. What is the best source of public information on your SC/QSE business (e.g., website), if any?

4. What electric markets does your SC/QSE business serve? Please list the number of customers you presently have in each market, listing generators and load-serving entities separately.

5. What is the annual volume of MWh managed by your business?

6. Please describe the services offered by your business.

7. What was the initial capital cost of establishing your business? Please provide a breakdown of capital costs by major category to the extent possible (e.g., hardware, software, staff recruitment, real estate, etc.)

8. What is the annual cost to operate the business? Please provide a breakdown of operating costs by major category to the extent possible (e.g., direct labor, benefits, office supplies).

9. Please describe your pricing structure (i.e. provide transaction fees or other fee structure), including actual rates, and contractual terms for each service. If rates are typically negotiated with customers, please provide a best estimate of an average rate and a short description of typical contractual terms.

10. Please list the number of full-time, part-time and contract employees in your SC/QSE business.

11. To what extent have initial costs or ongoing costs contributed to efficiency or business improvements that are desirable regardless of your SC/QSE business?

12. Do you view your business as profitable?

13. Would you be willing to be contacted should we have further questions? If so, please provide your contact information.