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November 13, 2009

Members of Service List (EC05-110)

PAC-E-05-08

Re: Quarterly Market Monitoring Report

Dear Service List Member:

Please find attached the public (redacted) version of the Third Quarter 2009 Quarterly Market Monitoring Reports for MidAmerican Energy Company and PacifiCorp.

Regards,

Michael W. Chiasson

Michael W. Chiasson, P.E.
Vice President

Enclosure (2)

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QUARTERLY MARKET MONITORING REPORT ON THE MIDAMERICAN ENERGY COMPANY

For

July and August, 2009

Issued by:

Potomac Economics, Ltd.
Independent Market Monitor

CONFIDENTIAL MATERIAL REDACTED

Table of Contents

List of Figures

I. Overview

In connection with the acquisition by the MidAmerican Energy Holdings Company ("MEHC") of PacifiCorp ("PAC") in Federal Energy Regulatory Commission ("Commission") Docket No. EC05-110-000, the Commission accepted the market monitoring plans for the MidAmerican Energy Company ("MEC" or "the Company") and PAC, and Potomac Economics was retained as the independent market monitor for both companies. The plans established that separate reports would be produced for each company. This is the market monitoring report for the months of July and August of 2009 for MEC.

As of September 1, 2009, MEC became a transmission-owning member of the Midwest ISO. All functional control of its transmission system was turned over to the Midwest ISO at that time, which is subject to the Market Mitigation Measures specified in Module D of the Midwest ISO Open Access Transmission, Energy and Operating Reserve Markets Tariff. Accordingly, as MEC provided in notice to the Commission on June 29, 2009, the aforementioned market monitoring plan for MEC ceases as of August 31, 2009. Therefore, this is expected to be the final report under the MEC market monitoring plan.

The market monitoring plan for MEC is designed to detect any anticompetitive conduct from the operation of the Company's transmission system, including any transmission effects from the Company's generation dispatch. As stated in the plan:

> The Market Monitor shall provide independent and impartial monitoring and reporting on: (i) generation dispatch of MidAmerican, and scheduled loadings on constrained transmission facilities; (ii) information concerning the volume of transactions and prices charged by MidAmerican in the electricity markets affected by MidAmerican before and after MidAmerican implements redispatch or other congestion management actions; and (iii) MidAmerican's calculation of Available Transmission Capability ("ATC") and Total Transfer Capability ("TTC") over transmission lines owned or controlled, in whole or in part, by MidAmerican.

The calculation of ATC and TTC as set forth in item (iii) was to be monitored by Potomac Economics until a Transmission Service Coordinator ("TSC") became operational and began calculating the ATC and TTC for the MEC system. Effective September 1, 2006, TransServ International, Inc. became the TSC for MEC. Accordingly, Potomac Economics no longer monitors the calculation of ATC and TTC.

To execute the monitoring plan, Potomac Economics routinely receives data from MEC that allows us to monitor generation dispatch, transmission system congestion, and the Company's operations and commercial activity during periods of congestion. We also collect certain key data ourselves, including OASIS data and market pricing data.

The purpose of this report is to provide the results of our monitoring activities and significant events on the MEC system[1] for July and August of 2009.

A. Market Monitoring

Potomac Economics performs the market monitoring function on a routine basis, as well as performing periodic reviews and special investigations. Our primary market monitoring is conducted via regular examination of market data relating to transmission outages, congestion, and transmission access. This involves examination of data on transmission outages and curtailments or other actions taken by MEC to manage congestion. Analyses of these data aid in detecting congestion and whether market participants have full access to transmission service.

Aside from routine monitoring of transmission outages, we are sensitive to atypical events such as price spikes, severe weather, and major generation outages that could have a negative impact on the capability of the transmission system. These events warrant particular attention in our monitoring for potential anticompetitive conduct.

Our periodic review of market conditions and operations is based on operating data provided by MEC, as well as data that we collect. This report contains our review of July and August of 2009. We divide the report into three sections. In the first section, we evaluate regional prices to assess overall market conditions. In the second section, we summarize transmission congestion in order to detect potential competitive problems. Congestion is identified by Transmission Loading Relief ("TLR") procedures events of level 3 and higher on flowgates that are electrically close to the MEC transmission system. In the final section, we address potential anticompetitive conduct. These analyses examine periods of congestion and evaluate whether MEC operating activities may be anticompetitive. The operating activities that we evaluate are generation

1 As specified in the monitoring plan, a draft of the findings has been submitted to MEC prior to submission to the Commission. MEC had no comments.

dispatch, wholesale purchases and sales, and transmission outages coincident with instances of congestion.

In addition to our periodic reviews, we may be requested to or deem it necessary to undertake a special investigation in response to specific circumstances or events. No such events occurred this quarter.

B. Summary of Quarterly Report

1. Wholesale Prices and Transactions

Prices. We evaluate regional wholesale electricity prices in order to provide an overview of general market conditions. Wholesale prices have fluctuated throughout these two months from \$22/MWh to \$44/MWh. Power prices generally moved in patterns consistent with the fluctuations in natural gas prices and load in July and August. This is consistent with expectations and the market results historically. Based on our evaluation of wholesale electricity prices in the MEC region, we did not identify a time period that merited a particular focus.

Sales and Purchases. MEC engages in wholesale purchases and sales of power on both a short-term and long-term basis. [redacted] Accordingly, we examine periods when such anticompetitive conduct may be possible.

2. Transmission Congestion

Curtailments. Congestion is managed on the MEC system by the Midwest ISO through the use of TLR procedures. MEC is under the umbrella of the Midwest ISO reliability authority. However, prior to September 1, 2009, the Midwest ISO did not control its transmission assets, nor were its generating assets registered with the Midwest ISO. MEC served as the balancing authority and transmission operator for its service territory. Monitoring and reporting on the effectiveness of the Midwest ISO in managing congestion does not fall within the scope of our monitoring. However, TLR events initiated by the Midwest ISO provide a useful measure of congestion on the MEC transmission system. During the period of study, there were 90 TLR events of a level 3 or higher within or electrically close to MEC's control area.

3. Potential Anticompetitive Conduct

Wholesale Sales and Purchases. We examine MEC sales and purchases delivered during the quarter. We focus on real-time bilateral contracts because these best represent the spot price of electricity and will most closely reflect power prices that might arise on the MEC system under conditions most conducive to market power. Under a hypothesis of market power, we would expect high sales prices or lower purchase prices during congested periods. Daily average transaction prices are volatile, ranging between [redacted] MWh and [redacted]/MWh. We focused our evaluation of MEC's generation and transmission on days with congestion that may have benefited MEC's net sales position. Our analysis indicated that MEC did not act anticompetitively to create the congestion.

Dispatch. To further evaluate potential market power or manipulation issues, we examine MEC's generation dispatch to determine the extent to which congestion may be caused or exacerbated by uneconomic dispatch. Congestion can result naturally when MEC or any utility dispatches its units in a least-cost manner. Such congestion does not raise competitive concerns. If a departure from least-cost dispatch ("out-of-merit" dispatch) occurs and causes congestion, and this departure is not justified, then this raises potential competitive concerns.

Using an estimated supply curve, we analyze MEC's actual dispatch to determine whether the actual dispatch departed significantly from what we estimate to be the most economic dispatch. In instances when dispatch departed substantially from the estimated optimal dispatch at the same time a congestion event occurred that may have been beneficial to MEC's short-term market positions, we evaluate the circumstances more carefully to determine if congestion was created and/or exploited by MEC. The out-of-merit quantities include units on unplanned outage and units that may not have been economic to commit. Hence, it will tend to overstate the quantity of generation that is truly out-of-merit. Our investigation found that all out-of-merit dispatch during the study period that had significant effects on transmission constraints was justified. Hence, we do not find evidence of anticompetitive conduct.

Transmission Outages. We evaluate MEC transmission outages in order to determine whether outages may have contributed to the congestion events that occurred during the study period. There were 50 transmission outages during July and August. Of these, 26 were coincident with TLR events and appeared to be unplanned. We investigated these outages in detail.

We found that three of the outages significantly contributed to the congestion and were planned less than two weeks in advance. Investigation into the outages revealed that they were justified. Hence, we find no evidence of anticompetitive conduct related to the outages.

4. Conclusion

Our review did not detect any anticompetitive conduct associated with the Company's operation of its transmission system or generation.

C. Complaints and Special Investigations

We have not been contacted by the Commission or other entities regarding any special investigation into MEC's market behavior, nor have we detected any conduct or market conditions that would warrant a special investigation.

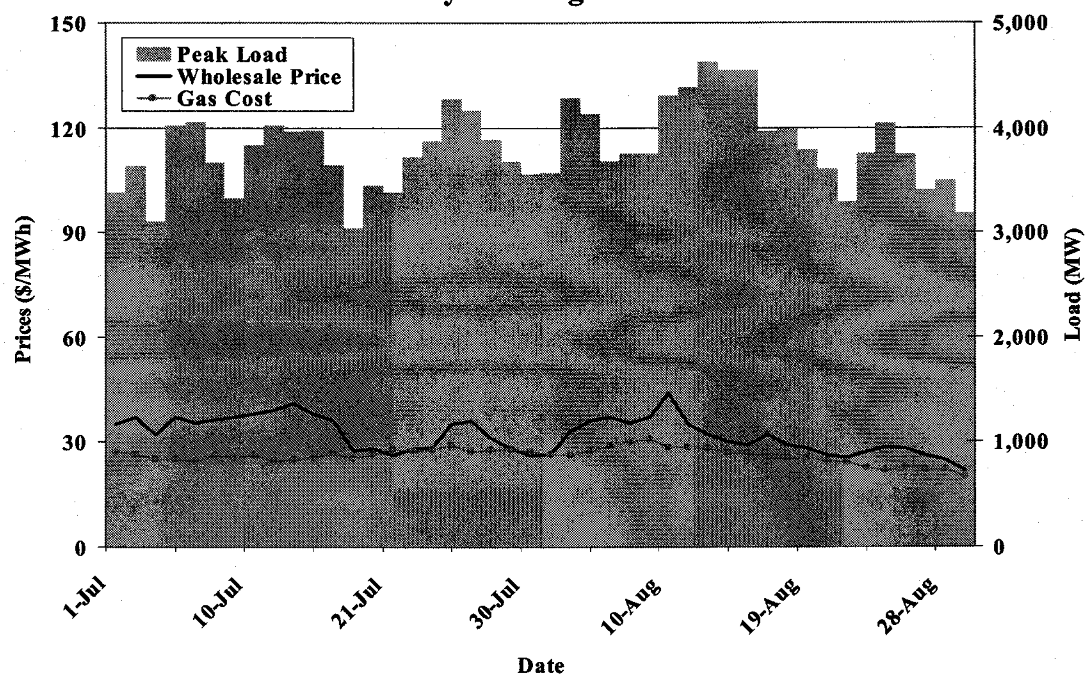
II. WHOLESALE PRICES AND TRANSACTIONS

A. Prices

We evaluate wholesale electricity prices in the MEC region in order to provide an overview of general market conditions. Examining price movements can provide insight into specific time periods that may merit further investigation, although they are not definitive indicators of anticompetitive conduct.

MEC was not part of a centralized wholesale market where spot prices are produced transparently in real time. Wholesale trading in the areas where MEC operates was conducted through bilateral contracts. Figure 1 shows the bilateral contract prices as reported by Platts during the quarter for Mid-Continent Area Power Pool South ("MAPP South"), which is the pricing point most proximate to the MEC system.

Figure 1: Wholesale Prices and Peak Load July and August 2009



Because power prices are influenced by fuel cost and load levels, the figure also shows daily peak load and natural gas cost at the Chicago City Gate translated to a power cost with an assumed 8,000 btu/kWh heat rate. This value roughly corresponds to the marginal operating cost of a natural gas-fired combined cycle power plant. Figure 1 shows that electricity prices were generally influenced by both natural gas cost and load during the quarter.

Figure 2 compares average Chicago City Gate natural gas prices with average MAPP South power prices for the months of July and August 2009 with average prices during the same period over the past three years.

Figure 2: Trends in Monthly Electricity and Natural Gas Prices July and August, 2006– 2009

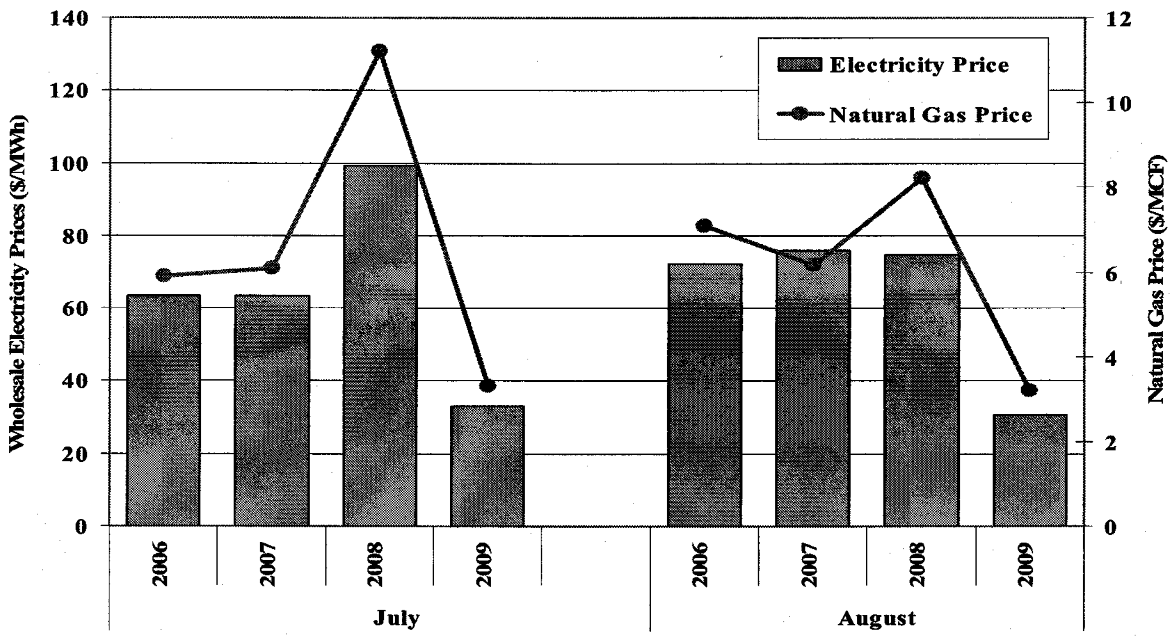


Figure 2 shows that electricity prices have generally moved with natural gas prices over time. Overall, our evaluation of wholesale electricity prices in the MEC region did not indicate a time period that warranted further investigation solely by virtue of price patterns.

B. Sales and Purchases

MEC engages in wholesale purchases and wholesale sales of power. These transactions are both firm and non-firm in nature. Figure 3 summarizes MEC's sales and purchase activity for trades that had deliveries during July and August of 2009. We consider only short-term trades because we are interested in transactions made by MEC that could provide MEC the opportunity to benefit from anticompetitive behavior. Short-term transactions include all transactions that are less than one month in duration. Longer-term transactions generally occur at predetermined prices that would not be directly affected by transitory periods of congestion that could be created with anticompetitive actions. Additionally, short-term transaction prices are good indicators of wholesale market conditions as they reflect the expectations of the market participants.

**Figure 3: Summary of MEC Sales and Purchases
July and August 2009**

[redacted]

As the figure shows, MEC's short-term [redacted]. At a broad level, the fact that [redacted] In Section IV, we evaluate the prices during congested periods to detect potential anticompetitive conduct.

III. TRANSMISSION CONGESTION

A. Overview

MEC is within the region for which the Midwest ISO serves as the reliability coordinator. However, prior to September 1, 2009, neither its transmission assets nor its generating assets were controlled by the Midwest ISO. Moreover, it was not subject to the monitoring and market power mitigation measures in the Midwest ISO Tariff. MEC served as the control area operator and transmission operator for its own service territory.

B. Congestion

Congestion is primarily monitored and managed through the use of TLR procedures. These procedures invoke schedule curtailments, system reconfiguration, generation re-dispatch, and load shedding as necessary to relieve congestion by reducing flows below the first-contingency transmission limits on all transmission facilities. The Midwest ISO, in its role as reliability coordinator for the region, manages all TLR procedures. Hence, the Midwest ISO monitors the power flows on all of MEC's transmission facilities (or "flowgates") and invokes a TLR event when the flow rises to within 95 percent of the transmission limit. MEC is only minimally involved in the TLR process and, therefore, the initiation of TLR events is not an area of monitoring concern. We evaluate TLR events in order to identify periods of congestion and determine whether MEC actions may have caused or exploited such events.

For the purposes of our analysis, we define an hour as congested when a TLR event of level 3 or higher is invoked during that hour on a flowgate that is significant to MEC's operations. We consider a flowgate significant to MEC's operations if (1) the associated transmission facilities are in one of the following control areas: MEC, Alliant Energy Corporate Services, LLC-West, or Dairyland Power Cooperative; (2) MEC, Alliant Energy, or Dairyland Power Cooperative is the transmission provider on the facilities, or (3) MEC's generation affects the flowgate significantly (as defined by a generation shift factor that is higher than three percent or lower than negative three percent). For the period of study, we identified 90 such TLR events. These 90 TLR events affected 19 flowgates.

In Section IV, we examine MEC's operating activities to determine whether they may have engaged in anticompetitive conduct to cause the congestion, and whether MEC was able to profit from it.

IV. Monitoring for Anticompetitive Conduct

In this section, we evaluate the available market and operating data to identify any evidence of anticompetitive conduct or market manipulation. The market monitoring plan calls for the market monitor to identify anticompetitive conduct, which includes the operation of either MEC's transmission assets or its generation assets to create transmission congestion and erect barriers to rival suppliers, thereby raising wholesale electricity prices. To identify potential concerns, we analyze MEC's wholesales sales in the first subsection below, its dispatch of its generation assets in the second subsection, and its transmission outages in the third subsection.

A. Wholesale Sales and Purchases

In this subsection, we examine transaction data to determine whether the prices at which MEC made sales or purchases may raise concerns regarding anticompetitive conduct that would warrant further investigation. We are particularly interested in periods when transmission congestion arises. If MEC was engaging in anticompetitive conduct to create the congestion, it could benefit by making sales at higher prices in the constrained areas or purchases at lower prices in areas adjacent to constrained areas.

We examined the real-time bilateral transactions made by MEC using MEC internal sales records. We focus on real-time transactions (traded the same day) because they best represent the spot price of electricity and would be more likely to reflect any effort to exercise market power. We would expect relatively high-priced sales or low-priced purchases during periods of transmission congestion if anticompetitive conduct was occurring.

Figure 4 shows the daily average prices received by MEC for real-time bilateral sales and purchases. The blue shading indicates days when curtailments occurred that could have potentially benefited MEC's position in the real-time bilateral markets.

To link curtailment events with days when curtailments could have potentially benefited MEC's position in the real-time bilateral markets, we calculate a measurement called the maximum daily effective market position ("Max Effect"). The Max Effect indicates the trade volume likely affected by a particular curtailment. Periods with curtailments and high Max Effect levels are further evaluated to determine if the transactions were done at pricing levels that raise potential competitive concerns.

The Max Effect is calculated in two steps. First, for each hour, constraint, and delivery point, we calculate a shift-factor-weighted[2] volume of trades by summing the product of the shift factors and the net trade volumes (purchases minus sales). These values represent the implied flows across each constraint that are caused by all of MEC's purchases and sales. For each hour and each constraint, the values are summed across all delivery points. Second, from this set of values, we select the highest hourly value of the day for any single constraint. If the highest value is positive, it appears on Figure 4 as the Max Effect.

Figure 4: Prices Received for MEC Sales and Purchases

[redacted]

The weighted average daily prices of MEC's sales range between [redacted]/MWh and [redacted] MWh. The volume-weighted average daily sales price was [redacted]/MWh. On days with curtailments that may have benefited MEC's net sales position, the average sales price was [redacted]/MWh. The weighted average daily prices of MEC's purchases range between [redacted]/MWh and [redacted]/MWh. The volume-weighted average daily purchase price was [redacted] MWh. On days with potentially beneficial curtailments, the average purchase price was also [redacted] MWh. At a broad level, MEC's weighted

2 The relationship between constrained paths and market delivery points is determined through shift factors, which are the portion of power injected at the market delivery point that flows over the constrained transmission path. Shift factors between -.01 and .01 are set to zero.

average purchase prices and sales prices during times of potentially beneficial congestion were about the same as other times during the quarter. During these times, the sales prices were about [redacted]/MWh lower and the purchase prices were about [redacted] MWh lower. Overall these statistics do not raise any competitive concerns.

We evaluated the five days that had a positive Max Effect greater than 55MW coincident with either higher MEC sales prices or lower MEC purchase prices than the prevailing market prices at the time. We found the following:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

Our primary concern is whether MEC created the congestion anticompetitively through generation and transmission operations. The circumstances surrounding the five congestion

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4 [redacted]

events above raise potential concern. These events require additional attention in our evaluation of MEC's generation dispatch and transmission outages in the remainder of this section.

B. Generation Dispatch

In this subsection, we examine the Company's generation dispatch to determine the extent to which congestion may have been the result of uneconomic dispatch. Therefore, we first evaluate MEC's dispatch during the study period to determine whether it was consistent with the least-cost use of its resources. Congestion can result naturally when MEC or any utility attempts to dispatch its units in a least-cost manner. This does not raise competitive concerns. If a departure from least-cost dispatch ("out-of-merit" dispatch) occurs unjustifiably and it causes congestion, this can raise potential competitive concerns. We consider a unit to be out-of-merit when it is dispatched, but could have been replaced by lower-cost generation that was not dispatched.

In order to identify out-of-merit dispatch, we first estimate MEC's marginal cost curve or "supply curve".[5] To estimate marginal costs, we used incremental heat rate curves, fuel cost, and other variable operations and maintenance cost data provided by MEC. This allowed us to calculate marginal costs for all of MEC's units. We ordered the marginal cost segments for each of the units from lowest cost to highest cost to represent the least-cost method of meeting various levels of demand. For our analysis, the curve is re-calculated daily to account for fuel price changes, planned maintenance outages, and planned deratings. Figure 5 shows the estimated supply curve for a representative day during the time period studied.

As Figure 5 shows, the marginal cost of supply increases as more units are required to meet demand, as expected. We used each day's estimated marginal cost curve as the basis for estimating MEC's least-cost dispatch for each hour in July and August. In general, this will not be the exact level of least-cost dispatch because we do not consider all operating constraints that may require MEC to depart from what our method identifies as the most economic use of its resources.

5 We use the term marginal cost loosely in this context. The value we calculate is actually the incremental production cost and does not include opportunity costs, risks, and other factors not reflected in the incremental production cost.

Figure 5: MEC Supply Curve

[redacted]

For example, our analysis does not model generator commitments, assuming instead that all available generators are online. While market monitoring resources could have been expended to refine the estimated generator commitment and dispatch to make it correspond more closely to actual operating parameters (i.e., start costs, run-time and down-time constraints, etc.), we believe this simplified incremental-operating-cost approach is adequate to detect instances of significant out-of-merit dispatch that would have a material effect on the market.

When a unit with relatively low running costs is justifiably not committed, our least-cost dispatch will overstate the out-of-merit quantities because it will identify the more expensive unit being dispatched in its place as out-of-merit. This may result in higher levels of out-of-merit dispatch during low-load periods when it is not economic to commit certain units.

Other justifiable operating factors that cause the out-of-merit dispatch to be overstated are energy limitations, ancillary services, and ramp rates. An example of an energy limitation is the governmental imposition of environmental permits that only allow a plant to operate for a specific number of hours per year. Because the plant is still capable of operating at full load for a shorter time period, the condition does not result in a planned outage or derating. The necessity to limit operating hours can cause the out-of-merit values to be overstated.

Ancillary services requirements such as spinning reserves, system ramp rate limitations, and AGC control requirements can make it operationally necessary to dispatch a number of units at part load rather than having the least expensive unit fully-loaded. These operational requirements can cause the out-of-merit values to be overstated. For our analysis, the accuracy of a single point is not as important as the trend or any substantial departures from the typical levels.

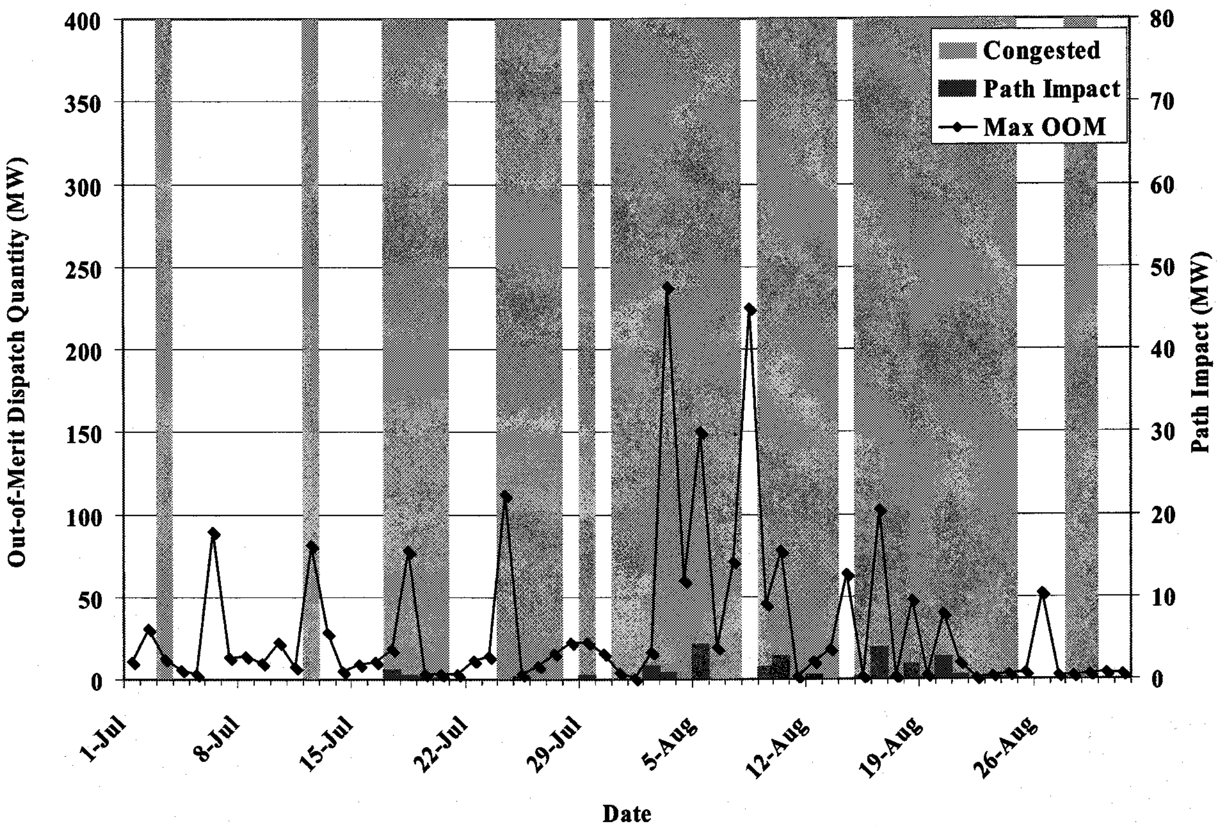
Our analysis does not model ramp rates[6]. We attempt to avoid ramping periods by focusing on on-peak hours from hour ending 12 to hour ending 22. However, in the event of a unit returning from outage during peak hours, our analysis may overstate the out of merit quantity because the unit is not immediately available at full capacity.

Figure 6 shows the daily maximum out-of-merit dispatch for the peak hours of each day in the study period. Also shown in the figure are days with congestion (i.e., a TLR event rated 3a or higher in effect) represented as blue bars. For these days, the out-of-merit dispatch displayed corresponds to the hour when the impact of the out-of-merit dispatch on the congested path was at its daily maximum. The figure also shows "Path Impact" (red bars). This is a calculation of the power flow change on the congested facilities as a result of the out-of-merit dispatch. In other words, if dispatch had been "in-merit", flow on the congested path would have been lower by the amount shown. The impact was determined using generation shift factors.[7]

6 Ramp rate is defined as the expected response rate of a generator measured in MW/minute and is used to determine the amount of time necessary for a unit to change output levels.

7 Generation Shift Factors are defined as the incremental increase or decrease in flow on a flowgate divided by an incremental increase or decrease in a Generation Resource's output.

Figure 6: Out-of-Merit Dispatch and Congestion Events



As the figure shows, the impact from out-of-merit generation dispatch was minimal during the quarter. The maximum impact contributed 4 MW of increased flow over a congested path while the out-of-merit generation was 150 MW. This occurred on August 5, 2009 and was due to Neal Unit 4 incurring a forced outage to repair a reheat tube leak. We do not find evidence of anticompetitive conduct.

Of five days identified above in the purchases and sales section only August 16, 2009, coincided with a significant out-of-merit event. The out-of merit dispatch on this day was 103 MW and the impact was 3.9 MW. The out-of-merit dispatch was due to [redacted] We do not find evidence of anticompetitive conduct.

C. Transmission Outages

We evaluate MEC transmission outages in order to determine whether outages may have led to the congestion events experienced during the time period of our report. We reviewed entries in the Midwest ISO Outage Scheduler that indicate the date, duration, and nature of the transmission system outages. There were 50 transmission outage entries for the MEC area during the study period. Of the 50 outages, 26 were concurrent with congestion events, lasted at least two hours, and were requested less than two weeks in advance. We examined these outages in more detail to determine the Line Outage Distribution Factor (LODF)[8] of the transmission element that was in outage relative to the monitored element of each flowgate that was subject to a TLR event of level 3a or higher. The LODF indicates how much the outage affects the monitored element. Hence, an outage with a large LODF indicates an outage that potentially had a significant contribution to the need for a TLR event. We found three outages that had a significant impact[9] on the monitored elements, which we evaluated in more detail.

The [redacted] was taken out of service for a five-hour scheduled outage on July 16, 2009. At the time [redacted] was subject to a TLR event. The line outage was not the cause of the TLR event because the TLR event lasted longer than the line outage. However, the LODF is strong enough to have an effect. The outage was taken to replace broken guy wires and anchors on one of the structures.

The [redacted] line was forced out of service on automatic relay action on July 25, 2009. The line was in outage for fifteen hours. This outage may have contributed to TLR events on [redacted] The cause of the outage was found to be a bad lightning arrestor at the [redacted].

The [redacted]e was taken out of service for a four-hour scheduled outage on August 3, 2009. This led to TLRs on [redacted] The outage was taken to repair an infrared hot spot located on a disconnect switch at [redacted]

Our review of the transmission outages did not identify events that caused congestion significant to the five days identified above in the purchases and sales section.

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8 Line Outage Distribution Factors (LODFs) are a sensitivity measure of how a change in a line's status affects the flows on other lines in the system. On an energized line, the LODF calculation determines the percentage of the present line flow that will be transferred to other transmission lines after the outage of the line.

9 A transmission outage is considered significant if over 3.5 percent of the pre-outage flow on the outaged line is transferred to the monitored element (pre-contingent) of the constraint (line outage distribution factor > 3.5 percent).

10 [redacted]

More broadly, our review of outages revealed that the line outages were justified and we found no other issues that raise potential competitive concerns.

D. Conclusions

Based on our overall analysis of MEC's conduct and the market outcomes, we find no evidence of anticompetitive conduct during the period of study.

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IDAHO PUBLIC UTILITIES COMMISSION

QUARTERLY MARKET MONITORING REPORT ON PACIFICORP

Third Quarter of 2009

Issued by:

Potomac Economics, Ltd.

Independent Market Monitor

CONFIDENTIAL MATERIAL REDACTED

Table of Contents

List of Figures

I. Overview

In connection with MidAmerican Energy Holdings Company's ("MEHC's") acquisition of PacifiCorp ("PAC" or the "Company") in Federal Energy Regulatory Commission ("Commission") Docket No. EC05-110-000, the Commission accepted market monitoring plans for PAC and MidAmerican Energy Company ("MEC") and Potomac Economics was retained as the independent market monitor for both companies. The plans established that separate quarterly reports be produced for each company. This is the market monitoring report for the third quarter of 2009 for PAC.

The market monitoring plan for PAC is designed to detect any anticompetitive conduct from operation of the company's transmission system, including any transmission effects from the company's generation dispatch. As stated in the plan:

> The Market Monitor shall provide independent and impartial monitoring and reporting on: (i) generation dispatch of PacifiCorp, and scheduled loadings on constrained transmission facilities; (ii) details on binding transmission constraints, such as transmission refusals, or other relevant information; (iii) operating guides and other procedures designed to relieve transmission constraints and the effectiveness of these guides or procedures in relieving constraints; (iv) information concerning the volume of transactions and prices charged by PacifiCorp in the electricity markets affected by these companies before and after the companies implement redispatch or other congestion management actions; (v) PacifiCorp's calculation of Available Transmission Capability ("ATC") and Total Transfer Capability ("TTC") over transmission lines owned or controlled, in whole or in part, by PacifiCorp; and (vi) plans for construction by PacifiCorp of expansions to its transmission facilities.

To execute the monitoring plan, Potomac Economics routinely receives data from PAC that allows us to monitor generation dispatch, transmission system congestion, and the Company's operational and commercial activity during periods of congestion. We also collect certain key data ourselves, including OASIS data and market pricing data.

The purpose of this report is to provide the results of our monitoring activities and significant events on the PAC system[1] during the third quarter of 2009.

1 As specified in the monitoring plan, a draft of the findings has been submitted to PAC prior to submission to the Commission. PAC had no substantive comments.

A. Market Monitoring

Potomac Economics performs the market monitoring function on a regular basis, as well as performing periodic reviews and special investigations. Our primary market monitoring is conducted by way of regular analysis of market data relating to transmission outages, congestion, and transmission access. This involves data on transmission outages, transmission reservation requests, Available Transfer Capability ("ATC"), and curtailments or other actions taken by PAC to manage congestion. Analyses of these data aid in detecting congestion and determining whether market participants have full access to transmission service.

In addition to the regular monitoring of outages and reservations, we also remain alert to other significant events, such as price spikes, major generation outages, and extreme weather events that could adversely affect transmission system capability and give rise to the opportunity for anticompetitive conduct.

Our periodic review of market conditions and operations is based on operating data PAC provides us, as well as other data that we collect on a routine basis. Our review consists of four parts. First, we evaluate regional prices and transactions to provide an assessment of overall market conditions. Second, we summarize transmission congestion in order to detect potential competitive problems. Congestion is identified by schedule curtailments on the PAC transmission system. Third, we evaluate the disposition of transmission service requests to analyze transmission access and to detect whether there are circumstances on the PAC system that require closer analysis. Finally, to monitor for anticompetitive conduct, we examine periods of congestion and evaluate whether PAC operating activities raise concerns that PAC appears to be behaving anti-competitively. The operating activities that we evaluate are wholesale purchases and sales, generation dispatch, transmission security events, and the curtailment and reduction of schedules.

In addition to our periodic reviews, we may from time-to-time be asked to or deem it necessary to undertake a special investigation in response to specific circumstances or events. No such events occurred this quarter.

B. Summary of Quarterly Report

1. Wholesale Prices and Transactions

Prices. We evaluate regional wholesale electricity prices to provide an overview of general market conditions. Over the course of the quarter, Eastern and Western control area electricity prices remained correlated with load and natural gas prices. Overall, the pattern did not indicate a particular time period of competitive concern.

Sales and Purchases. PAC engages in wholesale purchases and sales of power on both a short-term and long-term basis. [redacted]. Thus, we evaluate the prices of real-time transactions during congested periods in Section V.A to detect potential anticompetitive conduct.

2. Transmission Congestion

We studied congestion on the PAC system by examining schedule curtailments and reductions. In the period of study, PAC implemented 190 curtailments and schedule reductions totaling 16,451 MWh across 22 paths. We utilize curtailments as an indication of congestion. In addition, we analyze the accuracy of curtailments because unjustified curtailments can be used to foreclose competition.

3. Transmission Access

We evaluate the patterns of transmission requests and their disposition to determine whether market participants have had difficulty accessing the PAC transmission network. If requests for transmission service are frequently denied, this may indicate an attempt to exercise local market power. The volume of approved requests was higher than the levels observed in the third quarter of 2008 and higher than the second quarter of 2009. The volume of refusals was slightly lower than the preceding quarter, but higher than it was in the same quarter of the prior year. We see no evidence that these refusals were not legitimate. Our review of the disposition of transmission requests does not indicate anticompetitive behavior.

4. Potential Anticompetitive Conduct

Wholesale Sales and Purchases. We examined the transactions that PAC executed during the period of study. We focus on real-time transactions because these best represent the spot price of electricity and will most closely reflect power prices that might arise on the PAC system under conditions most conducive to market power. Under a hypothesis of market power, we would expect high sales prices or lower purchase prices during times when transmission congestion arises. Real-time daily average transaction prices ranged between [redacted] MWh and [redacted] MWh. We focused our evaluation of PAC's generation and transmission on days with congestion that may have benefited PAC's net sales position.

Dispatch. To further evaluate competitive issues, we examine PAC's generation dispatch to determine the extent to which congestion may be caused or exacerbated by uneconomic dispatch. Congestion can result naturally when PAC or any utility attempts to dispatch its units in a least-cost manner. Such congestion does not raise competitive concerns. If an unjustified departure from least-cost dispatch ("out-of-merit" dispatch) occurs, causing congestion, competitive concerns arise. Our investigation found that out-of-merit dispatch during the study period that had significant effects on transmission constraints was justified. Hence, this analysis did not reveal evidence of anticompetitive conduct.

Transmission Outages. We also evaluate PAC transmission security events and transmission outages in order to determine whether these events may have unduly caused congestion. We focused our analysis on six outage events that were associated with curtailments. We investigated these events and found no evidence of anticompetitive conduct.

Transmission Operations. We analyze PAC curtailments to determine whether curtailments are being properly implemented. PAC manages congestion, prioritization of schedules, and low voltage events with schedule curtailments. We scrutinized 25 curtailments that were at least 75 MW above what we estimate to be justified by net schedules and TTC. We were able to fully justify 22 of these 25 curtailment deviations. Given that 190 curtailments were implemented over the quarter, we find that actions taken to manage the system were accurate. We do not find evidence of anticompetitive conduct.

C. Complaints and Special Investigations

We have not been contacted by the Commission or other entities regarding PAC's market behavior. We also have not detected any conduct or market conditions that would warrant a special investigation. There were no complaints lodged against PAC regarding transmission access during the study period.

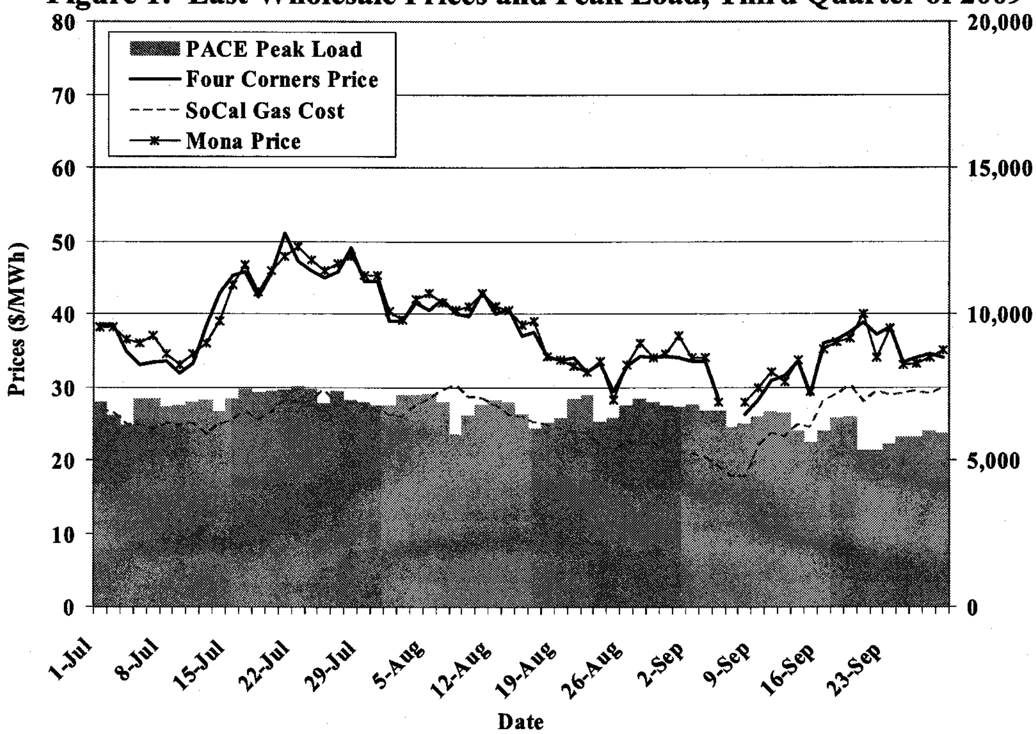
II. WHOLESALE PRICES AND TRANSACTIONS

A. Prices

We evaluate wholesale electricity prices in the PAC region in order to provide an overview of general market conditions. Examining price movements can provide insight into specific time periods that may merit further investigation, although they are not definitive indicators of the presence or absence of anticompetitive conduct.

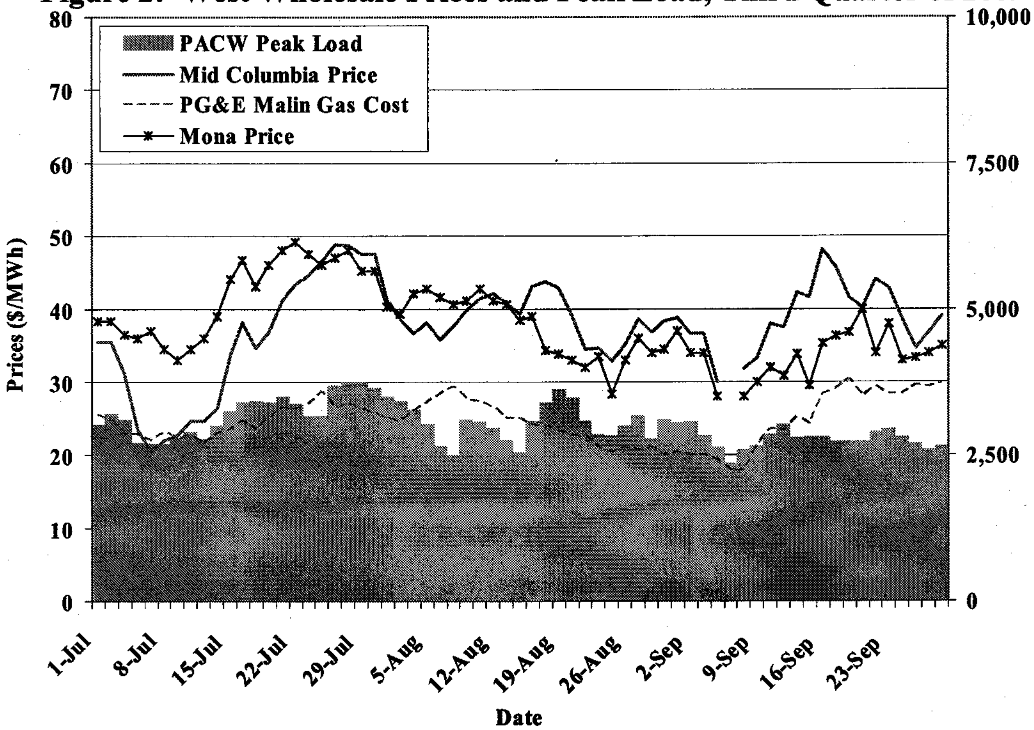
PAC is not part of a centralized wholesale market where spot prices are produced transparently in real time. Wholesale trading in the areas where PAC operates is conducted under bilateral contracts. Because of its geographic expanse, we consider two sets of pricing points to represent the Western and Eastern portions of PAC's system. Figure 1 shows the bilateral contract prices for Four Corners and Mona (representing the East) and Figure 2 shows the bilateral contract prices for Mid Columbia and Mona[2] (representing the West).

Figure 1: East Wholesale Prices and Peak Load, Third Quarter of 2009



2 Mona is a relatively illiquid and lightly traded market point in central Utah. It is included in both figures to provide a baseline for comparison between them.

Figure 2: West Wholesale Prices and Peak Load, Third Quarter of 2009



System load data is also shown because of the expected correlation with power prices. The Eastern control area load is shown on the East figure and the Western control area load is shown on the West figure. Natural gas prices are also shown because natural-gas-fired units are most often the marginal unit supplying the grid, and because fuel costs comprise the vast portion of a generating unit's costs. For the West analysis we use the daily price of natural gas deliveries at PG&E Malin (at the Northern California Border) translated to a power cost assuming an 8,000 btu/kWh heat rate. This number roughly corresponds to the fuel cost portion of the operating cost of a natural gas combined cycle power plant. For the East comparison, we use SoCal Border Gas (at the Southern California Border) price and apply the same power-cost conversion.

Prices for bilateral contract transactions are compiled and published by commercial pricing surveys. The bilateral pricing data shown in the figure above is published by Platts. The Mid Columbia pricing location includes a collection of hydroelectric units along the Columbia River in Oregon and Washington, and represents the value of electricity in the Pacific Northwest. This is a liquid point in PAC's Western control area. The Four Corners location is at the southern end of the PAC transmission system where New Mexico, Colorado, Arizona, and Utah meet. Prices at Four Corners represent the value of electricity in the Desert Southwest. This is the liquid point that is closest to PAC's Eastern control area.

Figure 1 and Figure 2 show that power prices at both Mid Columbia and Four Corners are generally correlated with fluctuations in natural gas prices and load, which is consistent with expectations in a properly functioning market.

The next analysis compares the average Four Corners and Mid Columbia power prices for the period from July 2006 through September 2009 with average prices during the same period over the past three years. These results are shown together with the average Platts SoCal Border and PG&E Malin natural gas prices discussed above. As the figures show, electricity prices have generally been highly correlated with natural gas prices over longer timeframes.

Figure 3: East Trends in Monthly Electricity and Natural Gas Prices Third Quarter, 2006–2009

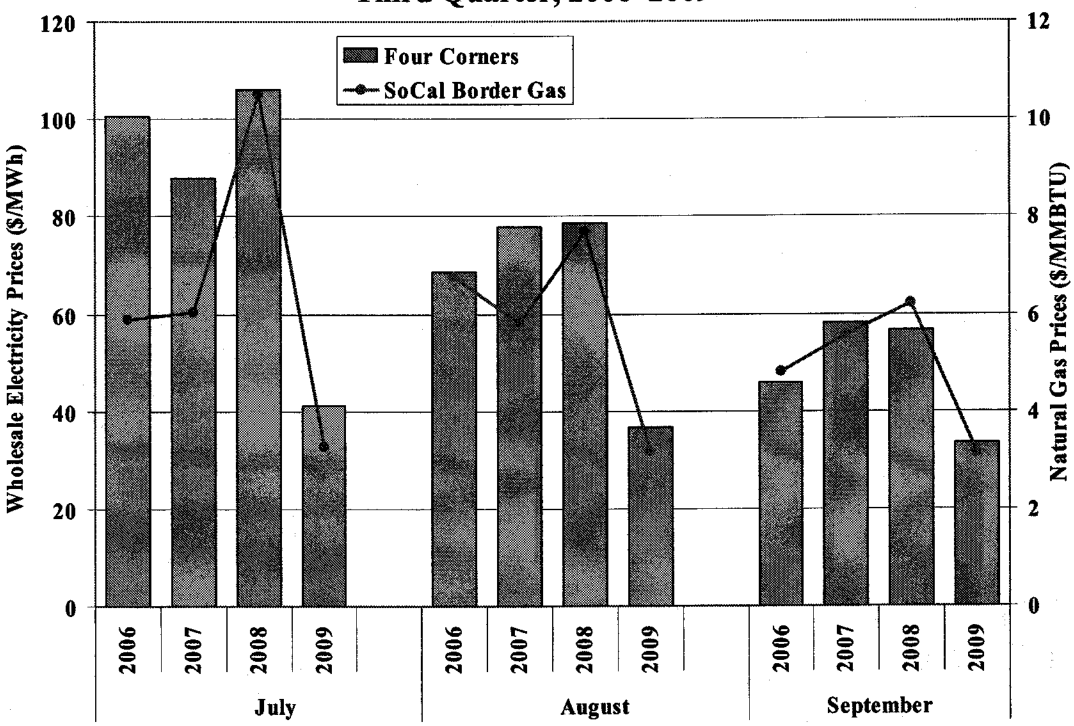
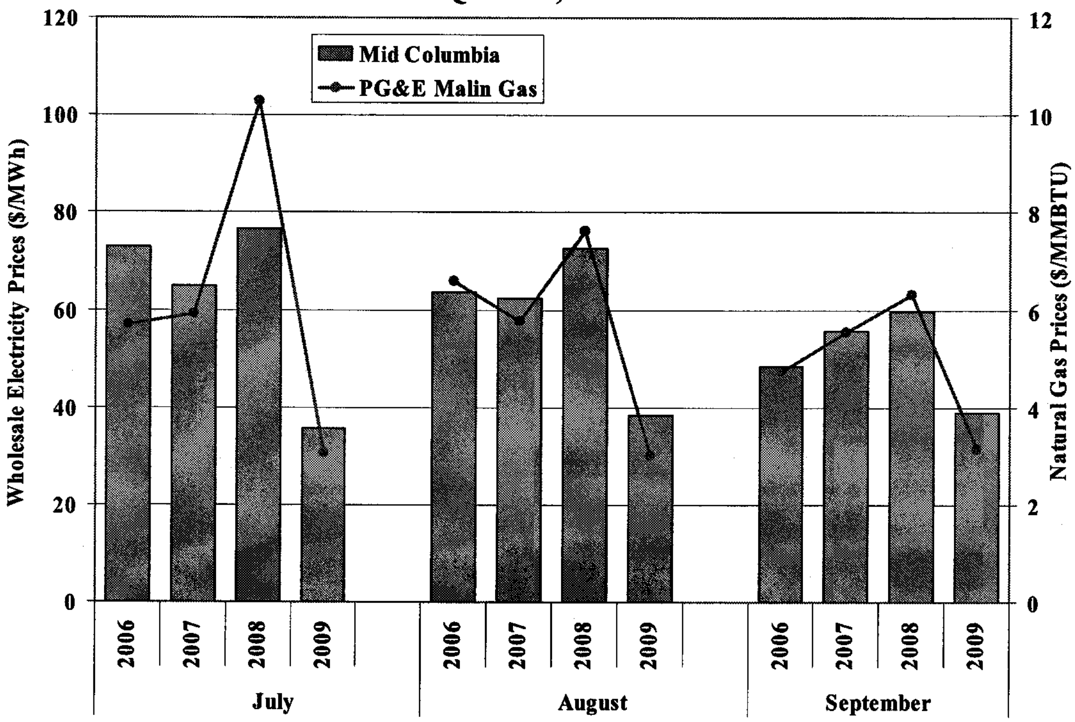


Figure 4: West Trends in Monthly Electricity and Natural Gas Prices Third Quarter, 2006–2009



Overall, our evaluation of wholesale electricity prices in the PAC region did not indicate any time period that merits further investigation solely by virtue of price patterns.

B. Sales and Purchases

PAC engages in wholesale purchases and sales of power, both firm and non-firm transactions. Figure 5 summarizes PAC's sales and purchases activity for trades that delivered during the third quarter of 2009. We consider only short-term trades because we are interested in transactions made by PAC where they could have benefited from any potential market abuse during this time period. Short-term transactions include all transactions that are less than one month in duration. Longer-term transactions generally occur at predetermined prices that would not be directly affected by transitory periods of congestion. Additionally, short-term transaction prices are good indicators of wholesale market conditions during periods of congestion.

Figure 5: Summary of PAC Sales and Purchases
Third Quarter of 2009

[redacted]

Figure 5 shows that PAC's [redacted] Thus, we evaluate the prices of real-time transactions during congested periods in Section V.A to detect potential anticompetitive conduct.

III. Transmission Congestion

A. Overview

PAC is a member of the Western Electricity Coordinating Council (WECC). In WECC, regional congestion is primarily managed by ensuring that the scheduled flows do not exceed flow limits on specified paths.[3] However, because actual flows sometimes exceed scheduled flows due to loop flow (or parallel path flow), additional congestion management procedures are employed.

Power flows in the WECC follow a relatively predictable pattern. Most of the flows over the network occur on the high-voltage facilities that roughly correspond to the geographic perimeter of WECC. The transmission system in the interior of the WECC boundaries operates at a lower voltage and carries less power. The topology of the transmission network causes power to circulate around the perimeter of the system. Typically, power transfers from the Pacific Northwest are scheduled south to California. However, sometimes this north-to-south power flow results in unscheduled increases in flow around the perimeter of the WECC system in the clockwise direction, passing through the PAC system and then on to California from the west through Arizona.

The PAC system consists of two control areas: PACW in Northern California, Western and Central Oregon and Southeast Washington, and PACE, which is in Wyoming, Southeast Idaho, and Utah. PAC extends across a broad geographical area, having a presence in six states. It has 16,400 miles of transmission lines and approximately 10,700 MW of owned or controlled net generation capacity. PAC operates a significant portion of the transmission facilities that provide north-to-south flow along the eastern perimeter of WECC.[4] These flows pass through a key interface that is operated by PAC known as Path 20 (sometimes referred to as Path C). Path 20 was a "qualified path" in the north-to-south direction under the UFRPs used by WECC.[5]

3 This is in contrast to how congestion is managed in the Eastern Interconnect where congestion management generally is focused on actual flows on flowgates as opposed to scheduled flows on contract paths.

4 While north-to-south flow is common, patterns of schedules and generation dispatch sometimes cause south-to-north flow.

5 WECC uses UFRPs when actual flow exceeds scheduled flow on a "qualified path". There are a limited number of qualified paths identified based on certain criteria that include the path having a history of unscheduled flow. The UFRP consists of a series of nine steps that are intended to relieve the congestion through the operation of equipment and, ultimately, the curtailment of schedules.

However, effective September 15, 2008, the path was disqualified by the WECC operating committee.

In this section, we investigate congestion on the PAC system by examining curtailments and transmission service request refusals. We also examine plans for construction of expansions to transmission facilities and found cases where the planned expansions may reduce congestion in constrained areas. Nothing from our review of PAC's planned expansions raised competitive concerns.

B. Transmission Operating Procedures

During the period of study, PAC implemented 190 curtailments (including cases when curtailments were reversed) and schedule reductions totaling 16,451 MWh across 22 paths.

Curtailments can be initiated when one of four conditions occurs: (1) the path is overscheduled (due to conditions on the transmission system causing a reduction in TTC); (2) a schedule with a higher priority reservation displaces a schedule with a lower priority reservation; (3) a low-voltage constraint is binding; or (4) actual flows exceed the capability of the path. The accuracy of these curtailments and schedule reductions are evaluated in Section V.

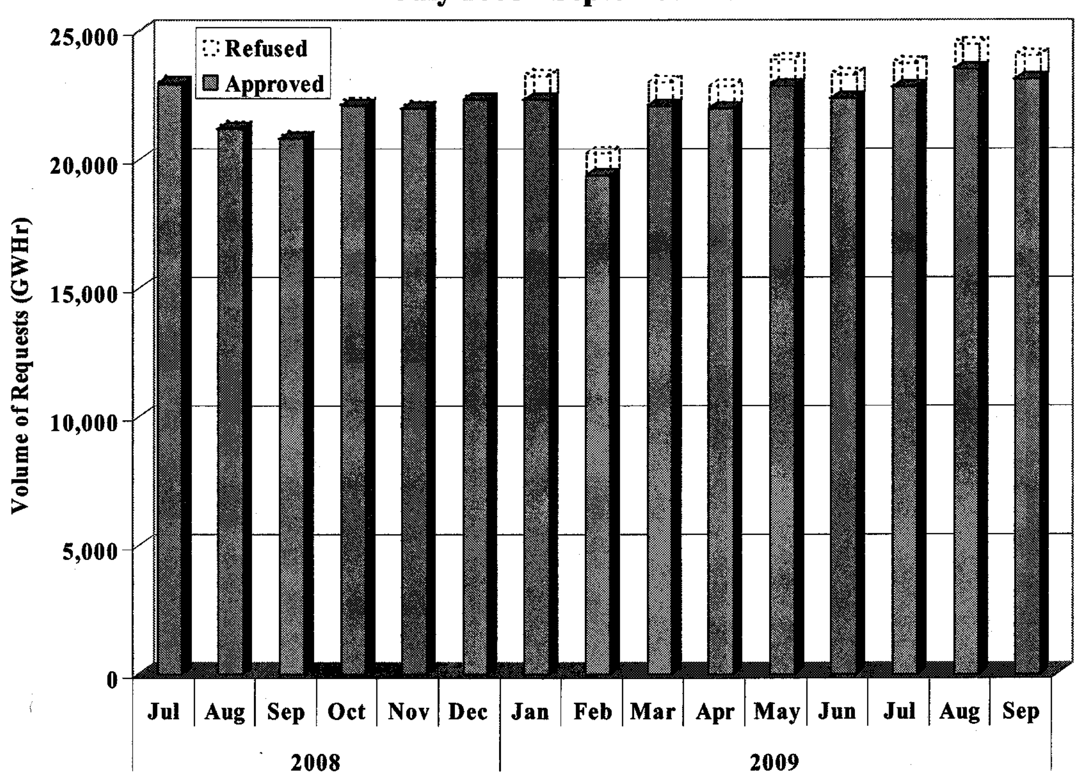
IV. Transmission Access

A main component of the market monitoring function is to evaluate transmission availability on the PAC system. In this section, we evaluate access to the transmission network by analyzing the disposition of transmission requests. The patterns of transmission requests and their disposition are helpful in determining whether market participants have had difficulty accessing the PAC transmission network.

In order to make this evaluation, we calculate the volume of requested capacity that spanned the time period under study. For example, if a request was approved in January for service in June, we categorize that as an approval for June. Because requests vary in magnitude and duration, we assign a total monthly volume (GWh) associated with a request, which provides a common measure for all types of requests. Hence, a yearly request for 100 MW has rights for every hour of the month for which the request spans, just a like a monthly request. A request covering less than the entire month is assigned the hours between its start and stop time.

Figure 6 shows the breakdown of transmission service requests in each month from July 2008 through September 2009 and summarizes the disposition of the requests.

Figure 6: Disposition of Requests for Transmission Service on the PAC System July 2008 - September 2009



The figure shows that the total volume of approved requests during the third quarter of 2009 was higher than the third quarter of 2008 and higher than the second quarter of 2009. The volume of refused service requests during the quarter was slightly lower than the preceding quarter, averaging 2827 GWHr. Hence, the approval rate increased from 95.4 percent for the second quarter of 2009 to 96 percent for the third quarter 2009. We reviewed the refusals for indications that they were not justified. We see no evidence that these refusals were not legitimate or that PAC had unreasonably restricted access to its transmission system.

To further evaluate the disposition of transmission requests, we compare the volume of transmission requests over the study period by increment of service to the requests from the corresponding period twelve months prior. This comparison is shown in Figure 7.

Figure 7: Disposition of Transmission by Duration of Service

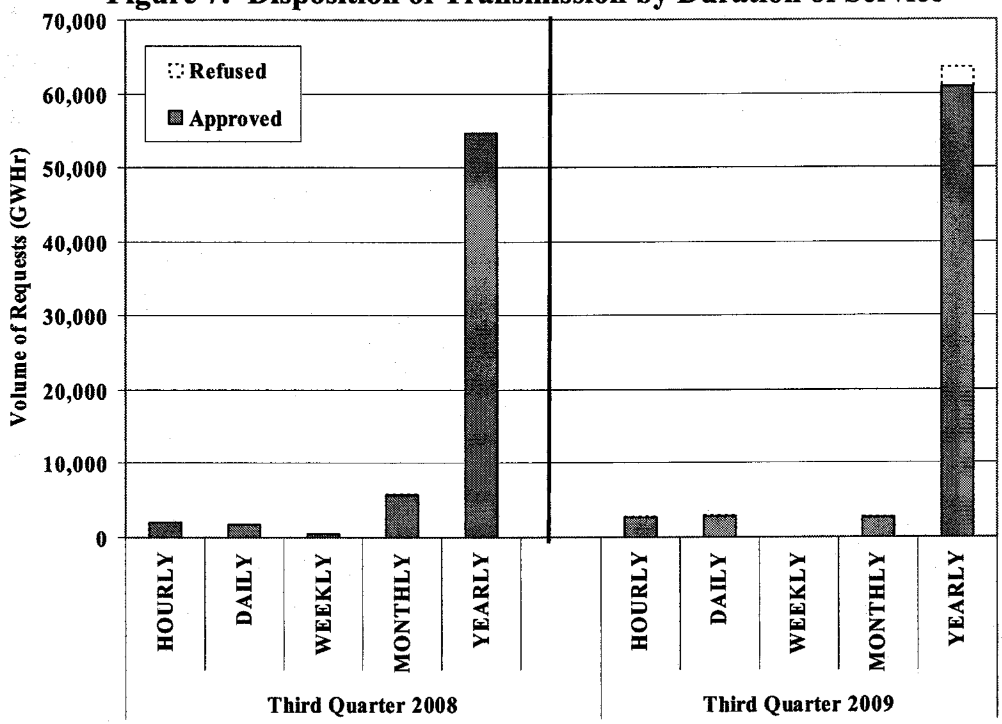


Figure 7 indicates an increase in the volume of approvals for all categories of service except for weekly and monthly. There was an increase in the volume of refused yearly requests, all of which were submitted prior to March 2007. They appear in this figure because the requested service spans the period of study. For these cases in general, the customers did not continue with the application and study process needed to ultimately perform system upgrades to make the transmission available. As a result, our review of the disposition of transmission requests does not raise any anticompetitive concerns.

V. MONITORING FOR ANTICOMPETITIVE CONDUCT

In this section, we evaluate the available market and operating data to identify any evidence of anticompetitive conduct or market manipulation. The market monitoring plan calls for identifying anticompetitive conduct, which includes conduct associated with the operation of either PAC's generation assets or its transmission assets that can create transmission congestion or erect barriers to rival suppliers, thereby raising electricity prices. To identify potential concerns, we analyze PAC's wholesale sales in the first subsection below, its dispatch of generation assets in the second subsection, transmission outages in the third subsection, and PAC's transmission operations in the fourth subsection.

A. Wholesale Sales and Purchases

We examine sales and purchase data to determine whether the prices at which PAC transacted power may raise concerns regarding anticompetitive conduct that would warrant further investigation. We are particularly interested in periods when transmission congestion arises. If PAC were engaging in anticompetitive conduct to create the congestion, it could potentially benefit by making sales at higher prices in constrained areas or purchases at lower prices adjacent to constrained areas. We examined the real-time bilateral transactions made by PAC using PAC internal records. We focus on real-time transactions because they best represent the spot price of electricity.

Competition is facilitated by the ability of rivals to reserve and schedule transmission service. This ability will be limited if ATC is unavailable, transmission requests are refused, or schedules are curtailed. Curtailments are also an indicator of congestion because they can be made when a path is over scheduled. If PAC's ability to curtail schedules is being abused, we would expect to see systematically higher prices for sales or lower prices for purchases coincident with curtailments.

Figure 8 shows the daily average prices received by PAC for real-time bilateral sales and purchases. The figure also indicates days when curtailments occurred that could have potentially benefited PAC's position in the real-time bilateral markets. A curtailment may impact system flows at market delivery points to the benefit of PAC's net position at those delivery points.[6] The maximum daily effective market position (labeled as "Max Effect" in the figure) is also displayed. This is the impact of PAC's sales and purchase transactions on the congested paths, calculated as the sum of the products of the volume of each market position and the shift factor of the delivery point to the curtailed path. "Max Effect" identifies periods when PAC is actively buying or selling in constrained areas and, therefore, could benefit itself by restricting other suppliers' access. The figure displays this value for the path and hour that has the maximum value for each day.

Figure 8: Prices Received for PAC Sales and Purchases
Third Quarter of 2009

[redacted]

The volume weighted average daily sales prices ranged from [redacted] MWh to [redacted] MWh and the average was [redacted]/MWh. We say a day has a "beneficial curtailment" if PAC is a net seller at a delivery point where the curtailment restricts supply or PAC is a net purchaser where the curtailment increases supply. On days when potentially beneficial curtailments occurred, the

6 The relationship between constrained paths and market delivery points is determined through shift factors, which are the portion of power injected at the market delivery point that flows over the constrained transmission path.

weighted average daily sales prices average [redacted] MWh. The volume weighted average daily purchases prices ranged from [redacted] MWh to [redacted] MWh and the average was [redacted]/MWh. On days with potentially beneficial curtailments, the weighted average purchase price was [redacted] MWh. These prices do not show a pattern of PAC benefiting from curtailments.

Though the overall price patterns do not raise concerns, we selected five days for closer examination. On these days, the maximum daily effective market positions were greater than or equal to 45 MW.

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted] Max Effect was a 300 MW sale at NOB (Nevada Organ Border) for [redacted]Wh.

Our primary concern is whether PAC anticompetitively created the congestion through generation and transmission operations. Accordingly, we focus particular attention on these days when we evaluate PAC's generation dispatch and transmission outages in the remainder of this section. We also review the accuracy of all curtailments in Section V.D below.

B. Generation Dispatch

To further evaluate whether PAC's conduct raises any anticompetitive concerns, we examine the company's generation dispatch to determine the extent to which congestion may have been the result of uneconomic dispatch of generation by PAC. Therefore, we first examine PAC's dispatch during the study period to determine whether it was consistent with the least-cost use of its resources. Congestion can result naturally when PAC or any utility dispatches its units in a least-cost manner, and does not raise competitive concerns in such circumstances. If a departure from least-cost dispatch ("out-of-merit" dispatch) occurs unjustifiably and it causes congestion, this effect can raise potential competitive concerns. We consider a unit to be out-of-merit when it is dispatched, but could have been replaced by lower-cost generation that was not dispatched.

The PAC system is made up of two control areas: PAC West and PAC East. PAC is the balancing authority for both of these control areas. The movement of power between the two systems is limited by both transmission capability and contractual rights. Efficient merit order dispatch is practical within each control area, but not necessarily between them due to these limits. To account for this, we evaluate out-of-merit dispatch for each control area separately. To identify out-of-merit dispatch, we first estimate each control area's marginal cost curves or "supply curves".[7] We used incremental heat rate curves, fuel costs, and other variable operations and maintenance cost data provided by PAC to estimate marginal costs. This allowed us to calculate marginal costs for PAC's units. We ordered the marginal cost segments for each of the units from lowest cost to highest cost to represent the cost of meeting various levels of demand in a least-cost manner. For our analysis, the curve is re-calculated daily to account for fuel price changes, planned maintenance outages, and planned deratings.

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7 We use the term marginal cost loosely in this context. The value we calculate is actually the incremental production cost and does not include opportunity costs, risks, and other factors not reflected in the incremental production cost.

Figure 9 shows the estimated supply curves for a representative day during the time period studied. As the figure shows, the marginal cost of supply increases as more units are required to meet demand, as expected.

Figure 9: PAC Supply Curves

[redacted]

We used each day's estimated marginal cost curves as the basis for estimating each control area's least-cost dispatch for each hour in the quarter. In general, this will not be the exact level of least-cost dispatch because we do not consider all operating constraints that may require PAC to depart from our estimate of the least-cost dispatch. The analysis is limited to peak hours to avoid times of ramping and commitment issues which prevent achievement of the theoretical least-cost dispatch.

This analysis does not model generator commitments, assuming instead that all available generators are online. While market monitoring resources could have been expended refining the estimated generator commitment and dispatch to make it correspond more closely to actual operating parameters (i.e., start costs , run-time and down-time constraints, etc.), we believe this simplified incremental-operating-cost approach is adequate to detect instances of significant out-of-merit dispatch that would have a material effect on the market.

When a unit with relatively low running costs is justifiably not committed, our least-cost dispatch will overstate the out-of-merit quantities because it will identify the more expensive unit being dispatched in its place as out-of-merit. This may result in higher levels of out-of-merit dispatch during low-load periods when it is not economic to commit certain units.

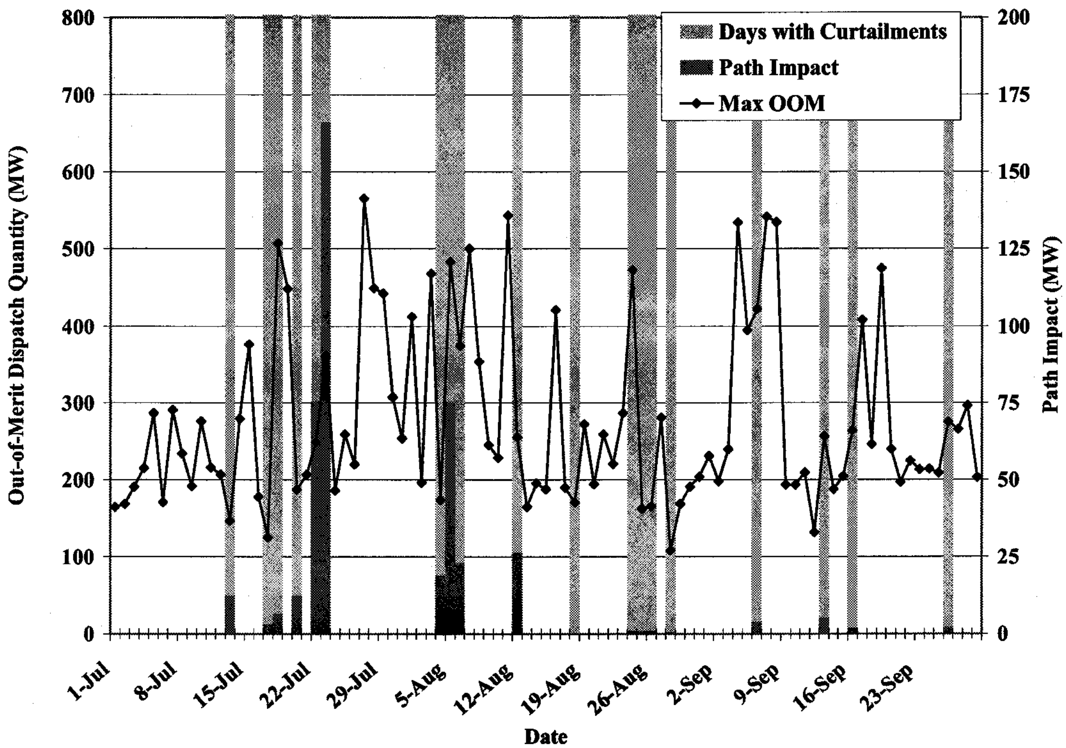
Other justifiable operating factors that cause the out-of-merit dispatch to be overstated are energy limitations and ancillary services. An example of an energy limitation is a governmental regulation limiting the number of hours a plant may run in a year. Since the unit is physically capable of producing, the limitation does not result in a planned outage or derating. The necessity to limit the hours of plant operation can cause the out-of-merit values to be overstated.

Ancillary services requirements such as spinning reserves, system ramp rate limitations, and AGC control requirements can make it operationally necessary to dispatch a number of units at part load rather than having the least expensive unit fully-loaded. These operational requirements can cause the out-of-merit values to be overstated.

The out-of-merit quantities include units on unplanned outage since a sudden unplanned outage may be an attempt to uneconomically withhold generation from the market. Hence, it will tend to overstate the quantity of generation that is truly out-of-merit. For our analysis, the accuracy of a single point is not as important as the trend and any substantial departures from the typical levels.

Figure 10 and Figure 11 shows the daily maximum "out-of-merit" dispatch for the peak hours of each day in the study period for the Eastern and Western control areas, respectively. Also shown in the figures are days when PAC curtailments were made on paths that were also loaded as a result of out-of-merit dispatch. These days are represented as blue bars. For these days when potential generation-induced curtailments occurred, the out-of-merit dispatch displayed corresponds to the hour when the impact of the out-of-merit dispatch on the congested path was at its daily maximum. The figures also show "Path Impact" (red bars). This is a calculation of the power flow change on the curtailed paths as a result of the out-of-merit dispatch. In other words, if dispatch had been "in-merit", flow on the curtailed path would have been lower by the amount shown. All curtailed paths are tested for impact from generation dispatch from generators in both control areas. The impact of out-of-merit dispatch was determined using generation shift factors[8].

Figure 10: East Out-of-Merit Dispatch and Congestion Events Third Quarter of 2009



As the analysis of the East control area in the figure shows, there were three days when out-of-merit dispatch was at least 240 MW and contributed at least 30 MW of increased flow over congested paths during the study period. We inquired further into these days and found the following:

- *July 22:* Naughton 1 and 2 were operating at part-load economically. [redacted] They were available for their full output with gas over-fire. However, their incremental cost while burning gas made them less economical than gas combined cycle units in the area which were running at the time. Thus, we dismiss this out-of-merit indication as being overstated because our screens did not capture the effects of the opacity limitation. At the

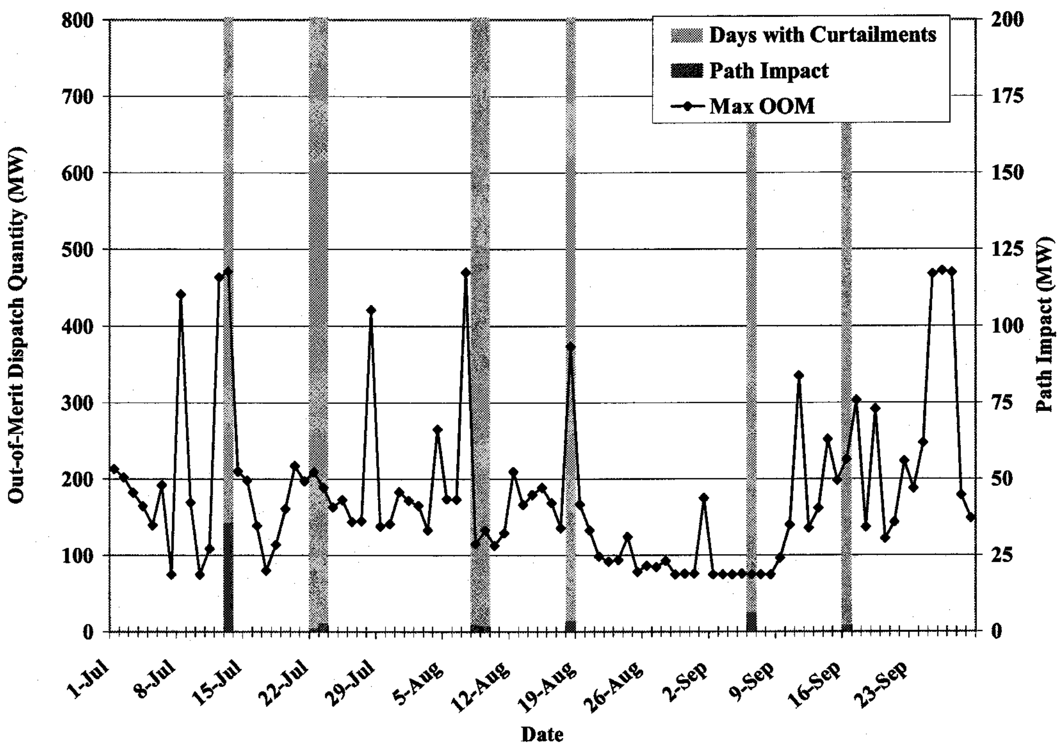
8 Generation Shift Factors are defined as the incremental increase or decrease in flow on a flowgate divided by an incremental increase or decrease in a Generation Resource's output.

time of the part-load operation, schedules on the Path C to Northern Utah path were being curtailed. The Naughton units are a strong raise-help (raising output relieves congestion) on this path by providing counter flow.

- *July 23:* Naughton 2 had a ten-hour forced outage when the [redacted] At the time of the outage, schedules on the Path C to Northern Utah path were being curtailed.

- *August 5:* Dave Johnston 4 tripped, initiating a twelve-hour forced outage. [redacted] We confirmed that the trip occurred by observing an abrupt loss of output that was reflected in the data. At the time of the outage, schedules on the Yellowtail to PAC Wyoming path were curtailed. The Dave Johnson units are a strong raise-help on that path.

Figure 11: West Out-of-Merit Dispatch and Congestion Events
Third Quarter of 2009



As the West control area figure shows, there was one day (July 13, 2009) when out-of-merit dispatch was at least 240 MW and contributed at least 30 MW of increased flow over congested paths during the study period. We inquired further into this day and found that the out-of-merit dispatch was justified due to Jim Bridger 3 incurring a 36-hour unplanned outage [redacted] This outage was coincident with curtailments on the Yellowtail to PAC Wyoming path. The Jim Bridger units are a raise-help because they provide counter flow. Also, the higher-cost unit that replaced the Jim Bridger generation (Chehalis) is a lower-help because the incremental flow from Chehalis to replace Jim Bridger generation increases flows across the constrained path.

In addition to the events associated with out-of-merit dispatch described above, we reviewed the five days identified in the Whole Sales and Purchases analysis above. We did not find any significant out-of-merit dispatch that affected constrained paths for those days.

Based on our review of the outage information in the operating logs, and information garnered from discussions with PAC personnel, we conclude that the aforementioned outages from both control areas were justified and did not constitute attempts to engage in anticompetitive behavior.

C. Transmission Outages

We evaluate PAC security events[9] to determine whether PAC's operation of transmission assets may have contributed to the congestion events that occurred during the study period of the report. We also evaluate transmission outages recorded in PAC's "Compass" system, its transmission outage logging system. Between the two systems we found six transmission outage events that were associated with schedule curtailments. This includes one transmission outage associated with curtailments that coincided with the three days in August of 2009 when PAC had purchase and sales positions that may have benefited from congestion as presented above. We reviewed these six outages and found the following:

- [redacted]

[9] Security events are defined as transmission security/reliability events that may impact the Provider's ability to schedule transactions.

[redacted]

- [redacted] Curtailments on Path C coincided with this outage. We find that the need for emergency repairs justifies taking the outage.

- [redacted] However, the outage was scheduled over two months in advance, so we do not find it to be anticompetitive. The timing of an outage scheduled far in advance prevents it from being an exploitation of short-term market conditions.

- [redacted] Curtailments on the Walla Walla to Mid Columbia path coincided with this outage.

- [redacted] This outage coincided with curtailments on three different paths in Wyoming.

- [redacted] This outage does not raise anticompetitive concerns because it was scheduled almost two months in advance and was taken to perform a justifiable work scope. Curtailments on the Yellowtail to PAC Wyoming path coincided with this outage.

Through our review of the records and conference calls with PAC staff, we find that all the outages were justified and the events raise no competitive concerns.

D. Transmission Operations

Under PAC operating procedures, path flows can be managed by curtailing transactions scheduled over the path. This can provide the opportunity for anticompetitive conduct by initiating curtailments when they are not necessary. By selectively initiating these procedures, PAC may have the ability to influence power prices in the region to its benefit.

Accordingly, we analyze the transmission schedules to determine whether curtailments are being initiated properly. PAC initiates curtailments when one of four conditions occurs: (1) the path is overscheduled (due to conditions on the transmission system causing a reduction in TTC); (2) a schedule with a higher priority reservation displaces a schedule with a lower priority reservation; (3) a low voltage constraint is binding, or (4) actual flows exceed the capability of the path.

To be over-scheduled, the net schedules (the sum of firm and non-firm schedules minus the sum of schedules that provide counter-flow) must exceed the TTC (less the scheduled amount of capacity reservations where applicable).[10]

We analyzed the 22 paths where curtailments were initiated by PAC. We compare aggregated ex post net schedules and real-time flows to TTC. Ex post net schedules are the net schedules actually realized at the end of the operating hour. PAC makes the curtailment decision twenty minutes prior to the operating hour. However, NERC standards also allow schedules (referred to as "etags") to be submitted up until twenty minutes prior to the hour. Because it takes ten minutes to evaluate a submitted schedule, the resulting net schedule can change from what it was when PAC initially made the curtailment decision. There may also be emergency etags submitted later than twenty minutes prior to the hour. Yet, this ex ante data is not available. Thus, utilizing ex post data provides only an approximation.

The curtailment deviations calculated and reported in the analysis below equal the TTC value minus the aggregated ex-post net schedules, except for the "Northern Utah to Path C" path. On the "Northern Utah to Path C", loop-flow is significant, so we calculate these curtailment deviations as the TTC value minus the maximum of either the real-time flows or the aggregated ex-post net schedules. Using real-time flow allows us to capture the loop-flow on this path. The curtailment deviations are limited to a ceiling equal to the curtailment amount and a floor of zero, since we are less concerned with under curtailments. In the absence of emergency tags or tags otherwise submitted after PAC makes its curtailment decision, if a path is over-scheduled and the curtailments are accurate, this value should be close to zero.[11] Figure 12 shows the results of this analysis.

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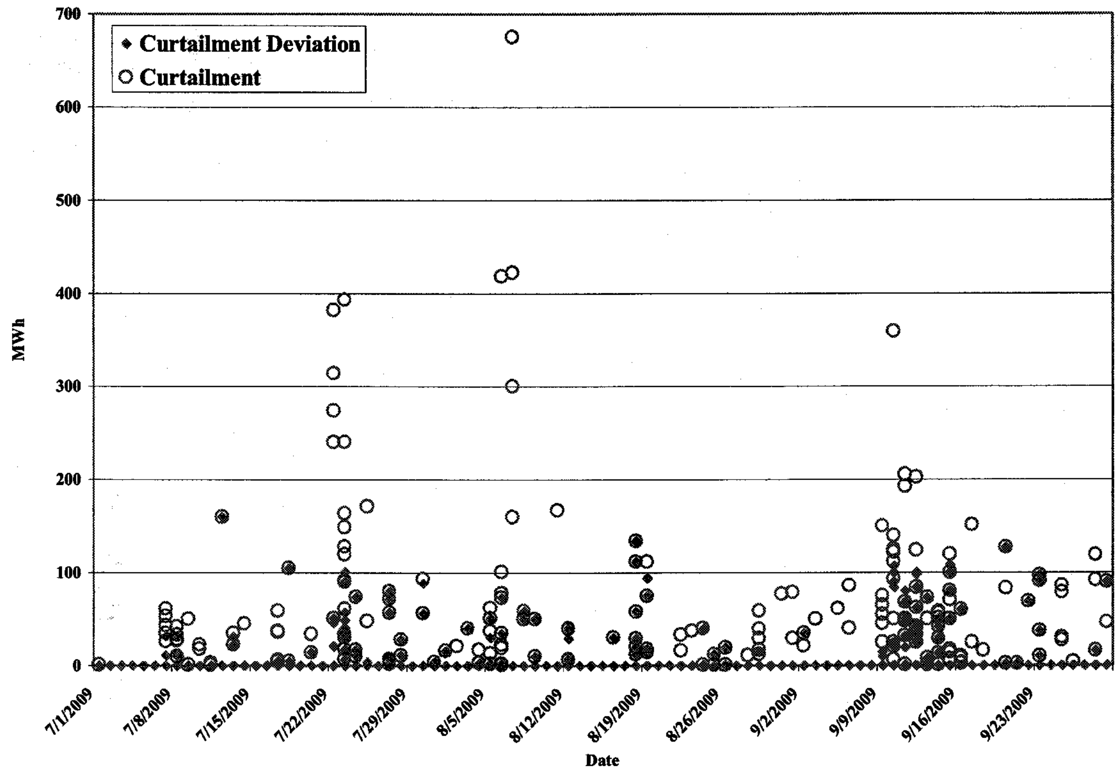
10 Effective April 28, 2008, PAC utilizes forecasted values for Path C capacity when making its curtailment decisions. Accordingly, when evaluating curtailments on the path "PACE to Path C", we utilize the forecasted capacity value rather than TTC.

11 The other reasons for curtailments aside from the path being over scheduled will not necessarily result in a curtailment deviation close to zero.

Figure 12: Curtailment and Curtailment Deviation
Third Quarter of 2009



Over the quarter, 190 curtailments were implemented. Of these, 25 curtailments had at least a 75 MW deviation. We reviewed all 25 for accuracy.

At the beginning of the quarter, PAC implemented a new software system called "CAS" to replace the KWH system. The CAS system had some problems that contributed to curtailment deviations. One issue was that the CAS system failed to reject some invalid schedules that were not supported by sufficient active transmission service rights. When invalid schedules were curtailed, they appeared as curtailment deviations in our screens, though the curtailments were justified. Of the 25 curtailment deviations that are under review, 18 were caused by this problem. When we adjusted for the invalid schedules, all but four events were shown to have no curtailment deviations. The deviations of the remaining four events were all less than 50 MW. So we dismiss them. PAC implemented upgrades to the CAS system on September 24, 2009 to resolve this issue.

We now review the remaining seven events.

Two events occurred on [redacted] There were 160 MW curtailment deviations for two consecutive hours caused by 160 MW schedule curtailments implemented on the [redacted] path. These curtailments were justifiably taken because the [redacted] The apparent deviation was caused by the TTC not immediately reflecting the line being out-of-service. The TTC was set to zero within two hours of the line outage.

On [redacted] there was a 100 MW curtailment deviation caused by a 100 MW schedule curtailment implemented on the [redacted]. However, PAC discovered and corrected this in a timely fashion by reloading the curtailed schedule.

On [redacted] hour ending 11[12], there was a 101 MW curtailment deviation on the [redacted] This was caused by an operator error in the use of a new curtailment tool associated with CAS. The operator failed to specify the direction of the curtailment, which resulted in curtailments being implemented in both directions. This 101 MW curtailment deviation is an example of a curtailment in the wrong direction. There were many other similar events, but none caused a deviation that was greater than 75 MW. PAC addressed this issue through email instructions to the operators later that same day and then again on September 10, 2009.

On [redacted] was a 150 MW curtailment deviation for one hour. The curtailments were justifiably taken because the [redacted] was forced out of service through automatic relay action. The apparent deviation was caused by a counter-flow schedule for 150 MW that was not curtailed.

On [redacted], there was a 160 MW curtailment deviation because curtailments were erroneously made for the [redacted] outage after the line was back in service. The event occurred because the update to the outage system that reflected the line status failed to transfer correctly to the rest of the systems.

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12 The curtailments noted for hour ending 11 are not the same ones that are referred to in the East control are out-of-merit dispatch for that same day, which are for hour ending 14. Although both sets of curtailments are for the same path and both directions were curtailed, this path was the proper direction for hour ending 14.

On [redacted] there was a 75 MW curtailment deviation on the [redacted] The limits were lowered due to the [redacted] The curtailments were a justified action to keep the physical flows within the revised limits.

Of the 25 curtailments that we reviewed, only two were found to be inaccurate or unjustified. Both were software related. With the new CAS system, it is understandable that defects need to be resolved and the operators need to get familiar with the system. We find that having only two curtailments identified as inaccurate does not raise concerns. Hence, we do not find evidence of anticompetitive conduct, and we find that actions taken to manage the system were very accurate.

E. Conclusions on Monitoring for Anticompetitive Conduct

Based on our analysis of PAC's conduct and the market outcomes, we find no conduct by PAC that raises potential competitive concerns during the period of study.