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May 14, 2009

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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 First Quarter 2009 Quarterly Market Monitoring Reports for MidAmerican Energy Company and PacifiCorp.

Regards,

Michael W. Chiasson

Michael W. Chiasson, P.E.
Vice President

Enclosures (2)

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QUARTERLY MARKET MONITORING REPORT ON THE MIDAMERICAN ENERGY COMPANY

For the

First Quarter 2009

Issued by:

Potomac Economics, Ltd.
Independent Market Monitor

CONFIDENTIAL MATERIAL REDACTED

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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 first quarter of 2009 for MEC.

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 the first quarter 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 the first quarter 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 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.

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.

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 the quarter from $[redacted]/MWh to $[redacted]/MWh. Power prices generally moved in patterns consistent with the fluctuations in natural gas prices and load in the first quarter. 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. MEC short-term [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, the Midwest ISO does not control its transmission assets, nor are its generating assets registered with the Midwest ISO. MEC serves 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 97 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 94 transmission outages during the quarter. Of these, 35 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.

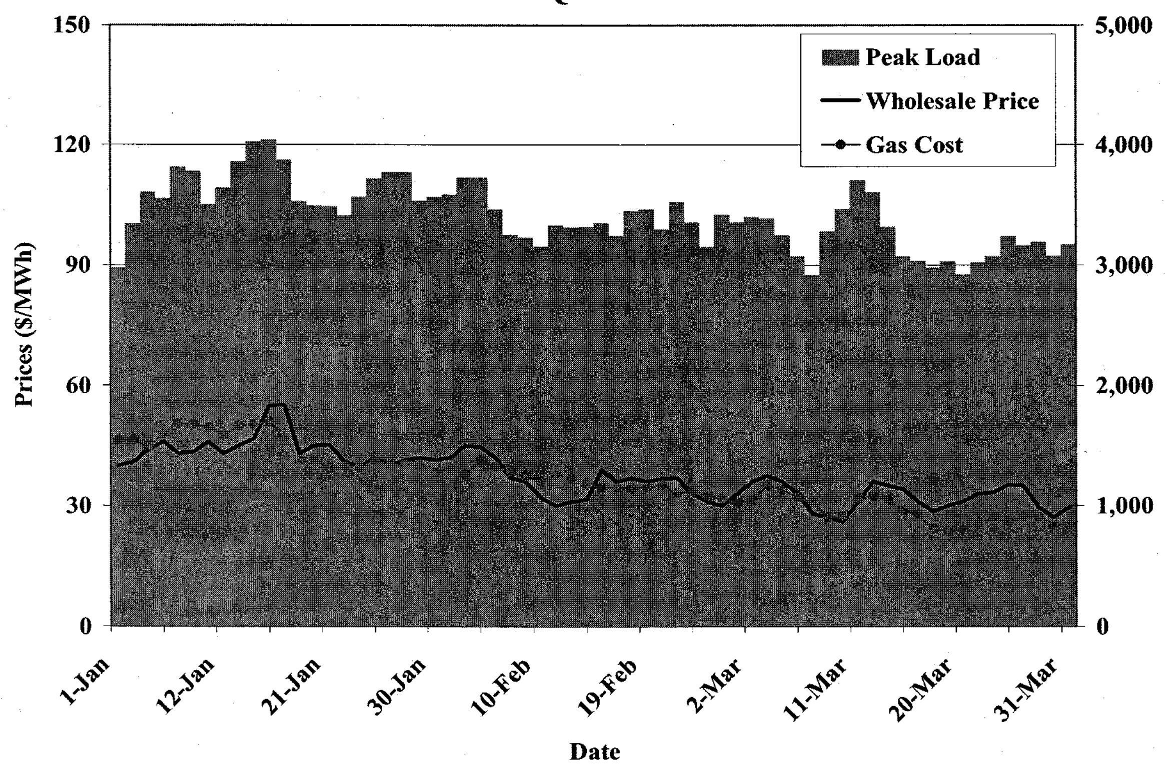
II. Wholesale Prices and Transactions

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 is not part of a centralized wholesale market where spot prices are produced transparently in real time. Wholesale trading in the areas where MEC operates is 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 First Quarter 2009



Because power prices are influenced by fuel cost and load levels, the figure also shows daily peak load and natural gas prices 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 prices 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 January through March 2009 with average prices during the same period over the past three years.

Figure 2: Trends in Monthly Electricity and Natural Gas Prices January through March, 2006– 2009

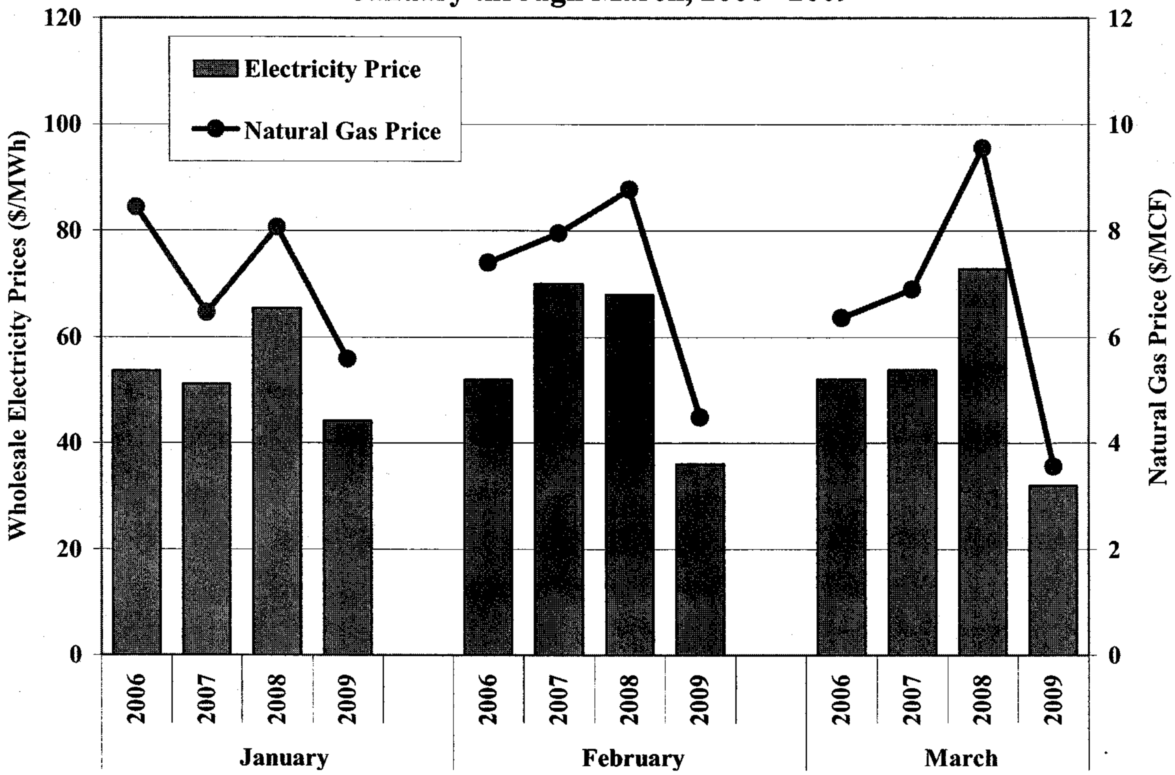


Figure 2 shows that electricity prices have generally moved with natural gas prices over time. Overall, our evaluation of wholesale electricity prices in the MEC region did not indicate a time period that warranted further investigation solely by virtue of price patterns.

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 the first quarter 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
First Quarter 2009

Redacted

As the figure shows, MEC's short-term [redacted] At a broad level, the fact that MEC's short-term [redacted] In general, a market participant exercising market power would be a short-term net seller making short-term sales at high prices. 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, neither its transmission assets nor its generating assets are controlled by the Midwest ISO. Moreover, it is not subject to the monitoring and market power mitigation measures in the Midwest ISO Tariff. MEC serves 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 97 such TLR events. These 97 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 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 higher and the purchase prices were the same as the average. Overall these statistics do not raise any competitive concerns.

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.

We evaluated the five days that had a positive Max Effect greater than 75MW coincident with either higher sales prices or lower purchase prices than the prevailing prices at the time. We found the following:

- **January 13, 2009:** The congestion was on flowgate [redacted].[3] At the time of the high Max Effect, [redacted]
- **February 11, 2009:** The congestion was on flowgate [redacted]. At the time of the high Max Effect, [redacted]
- **February 26, 2009:** The congestion was on flowgate [redacted]. At the time of the high Max Effect, [redacted]
- **March 22, 2009**: The congestion was on flowgate [redacted].[4] At the time of the high Max Effect, [redacted]
- **March 24, 2009:** The congestion was on flowgate [redacted]. At the time of the high Max Effect, [redacted]

Except for March 22 and March 24, the transactions at delivery points electrically close to the congestion were not at prices significantly more favorable than the prevailing prices at other delivery points. Hence, the curtailments do not indicate potential competitive concerns. Our primary concern is whether MEC created the congestion anticompetitively through generation and transmission operations. Accordingly, we focus particular attention on March 22 and March

3 [redacted]

4 [redacted]

24 when we evaluate 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 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 MEC to depart from what our method identifies as the most economic use of its resources.

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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.

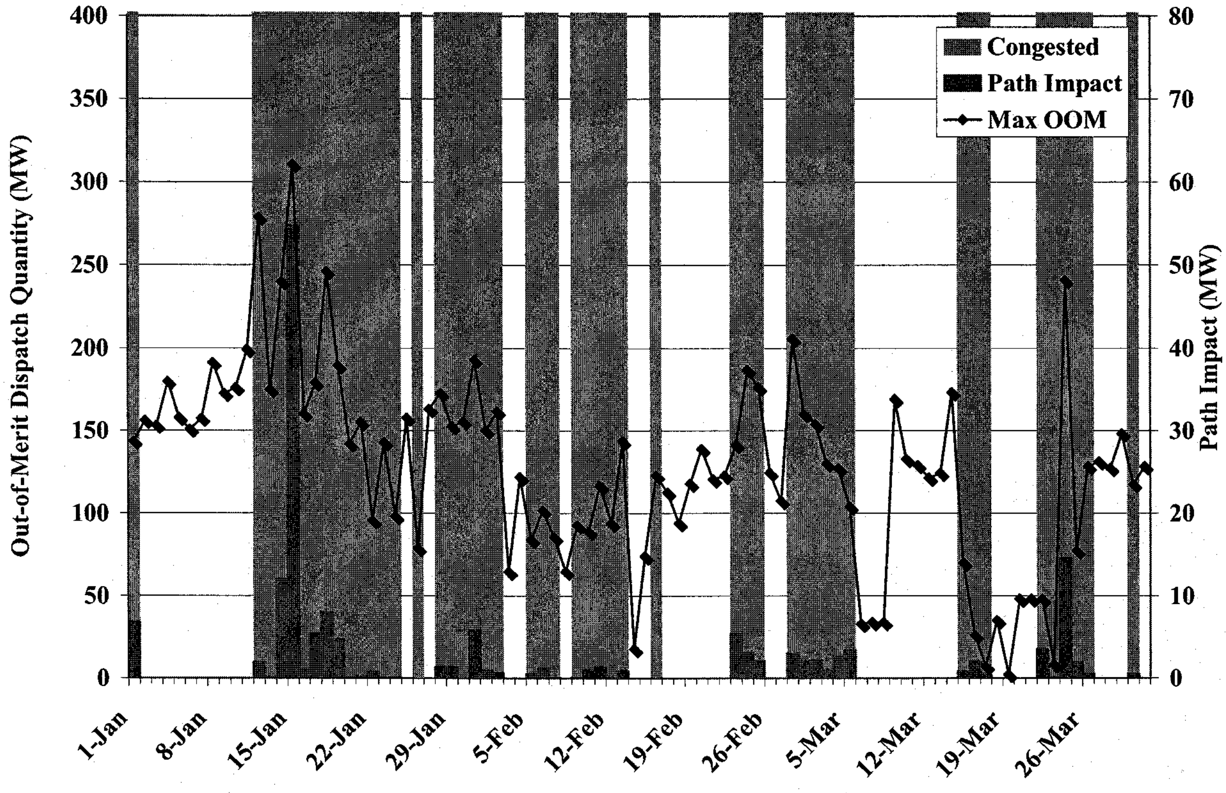
Our analysis does not model ramp rates[6]. We attempt to avoid ramping periods by focusing on on-peak hours from hour ending 12 to hour ending 22. However, in the event of a unit returning from outage during peak hours, our analysis may overstate the out of merit quantity because the unit is not immediately 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, there were three days (January 14, January 15 and March 24) when out-of-merit dispatch contributed at least 10 MW of increased flow over congested paths during the study period. We also include the two days that were identified in the sales and purchases analysis for further evaluation (March 22 and March 24). We examined these days in more detail and found the following events:

- **January 14, 2009:** [redacted] was near minimum-load while lower cost units at the [redacted] were at part-load. The reduced load at [redacted] added to the flows on flowgate [redacted][8] that was in TLR for some of this time. The units were committed to distribute operating reserves across multiple units.

- **January 15, 2009:** [redacted] was near minimum-load while lower cost units at the [redacted] were at part-load. The reduced load at [redacted] added to the flows on flowgate [redacted][9]

8 Flowgate [redacted]

9 Flowgate [redacted]

that was in TLR for some of this time. The units were committed to distribute operating reserves across multiple units.

- **March 22, 2009:** This date was examined due to the "Max Effect" value associated with flowgate [redacted] and purchase prices presented in the prior section. We determined that Out-of Merit dispatch did not have a significant affect on flowgate [redacted].
- **March 24, 2009:** [redacted] tripped on the [redacted] and [redacted]. The equipment tripped due to [redacted] caused by [redacted]. A portion of its capacity was replaced with generation at [redacted], which added to the flows on flowgate [redacted] that was in TLR for some of this time.

Our review of the documentation associated with these operational events indicated that all of the 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.

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 94 transmission outage entries for the MEC area during the study period. Of the 94 outages, 35 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)[10] 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[11] on the monitored elements, which we evaluated in more detail.

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[10] 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.

[11] 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).

[redacted] was out of service for a ten-hour planned maintenance outage starting on [redacted]. The outage was taken to [redacted]. The LODF was significant to flowgate [redacted], which had a TLR event during the outage.

[redacted] was taken out of service for 2.5 days starting on [redacted] This was a planned outage [redacted]. The LODF was significant to flowgate [redacted][12], which had TLR events during the outage.

[redacted] was forced out of service for 4 days starting on [redacted]. A structure that went down during severe weather conditions was replaced. The LODF was significant to flowgate [redacted], which had TLR events during the outage.

Only the third outage occurred on the days identified above when MEC had purchases and sales positions that could have potentially benefited. However, this outage was not near the constraints or delivery points identified in the purchases and sales analysis. Based on our review of outages, we find that the line outages were justified and no other issues would 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.

12 Flowgate [redacted]

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QUARTERLY MARKET MONITORING REPORT
ON
PACIFICORP

First Quarter of 2009

Issued by:

Potomac Economics, Ltd.
Independent Market Monitor

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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 first 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 first quarter of 2009.

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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, Northwest and Southwest electricity prices were fairly constant relative to other quarters. 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. PAC short-term wholesale [redacted] 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 358 curtailments and schedule reductions totaling 9,648 MWh across fifteen 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 first quarter of 2008 and lower than the fourth quarter of 2008. Although the volume of refusals was higher than it was in the same quarter of the prior year, we are primarily interested in approved volumes. 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 seven outage events that were associated with curtailments. We investigated these events and found no evidence of anticompetitive conduct.

Curtailments. 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 24 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 all but two of these 24 curtailment deviations. Given that 439 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.

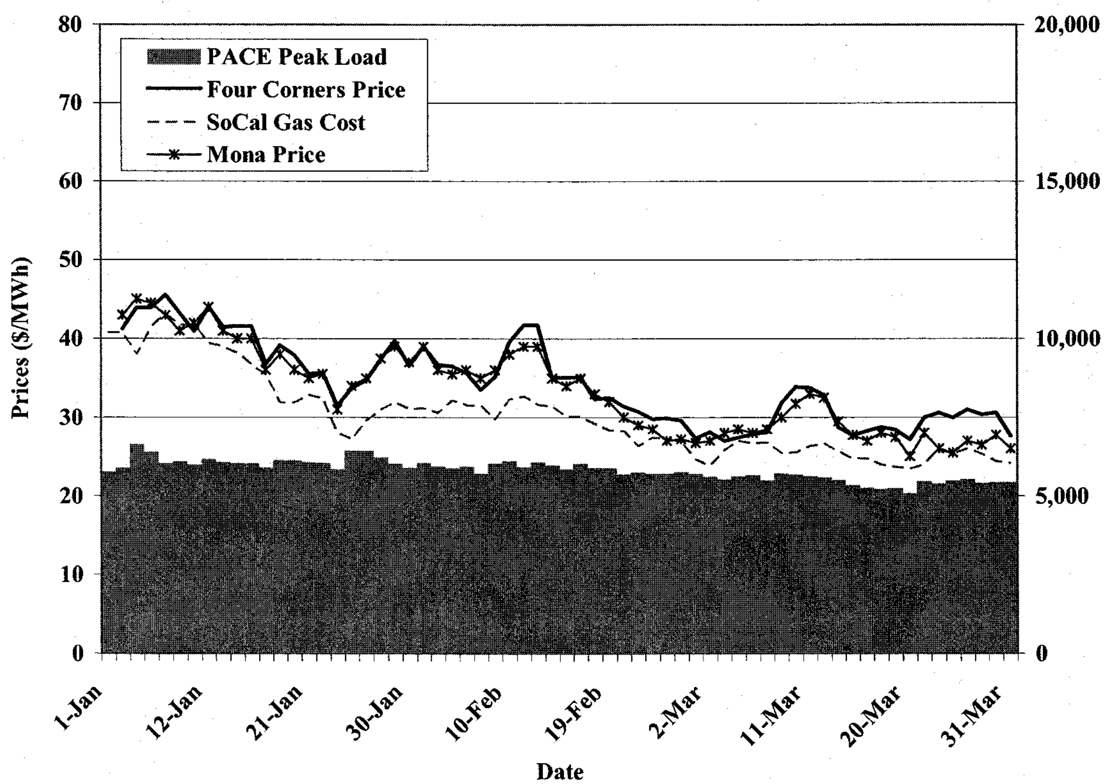
II. WHOLESALE PRICES AND TRANSACTIONS

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.

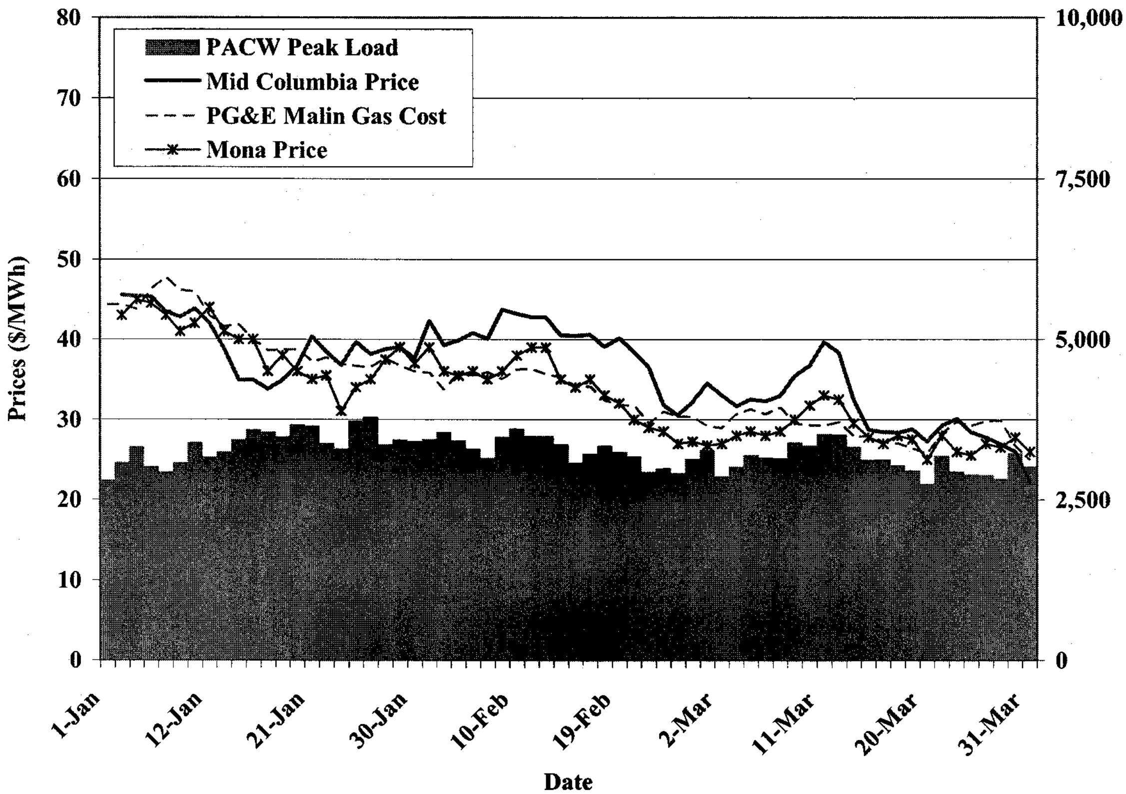
PAC is not part of a centralized wholesale market where spot prices are produced transparently in real time. Wholesale trading in the areas where PAC operates is conducted under bilateral contracts. Because of its geographic expanse, we consider two sets of pricing points to represent the Northwest and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

Figure 1: Southwest Wholesale Prices and Peak Load, First 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: Northwest Wholesale Prices and Peak Load, First 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 Southwest figure and the Western control area load is shown on the Northwest 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 Northwest 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 Southwest 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. 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.

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. The power prices for both areas declined with declining gas prices while the load was nearly flat.

The next analysis compares the average Four Corners and Mid Columbia power prices for the period from January 2006 through March 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 correlated with natural gas prices over time.

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

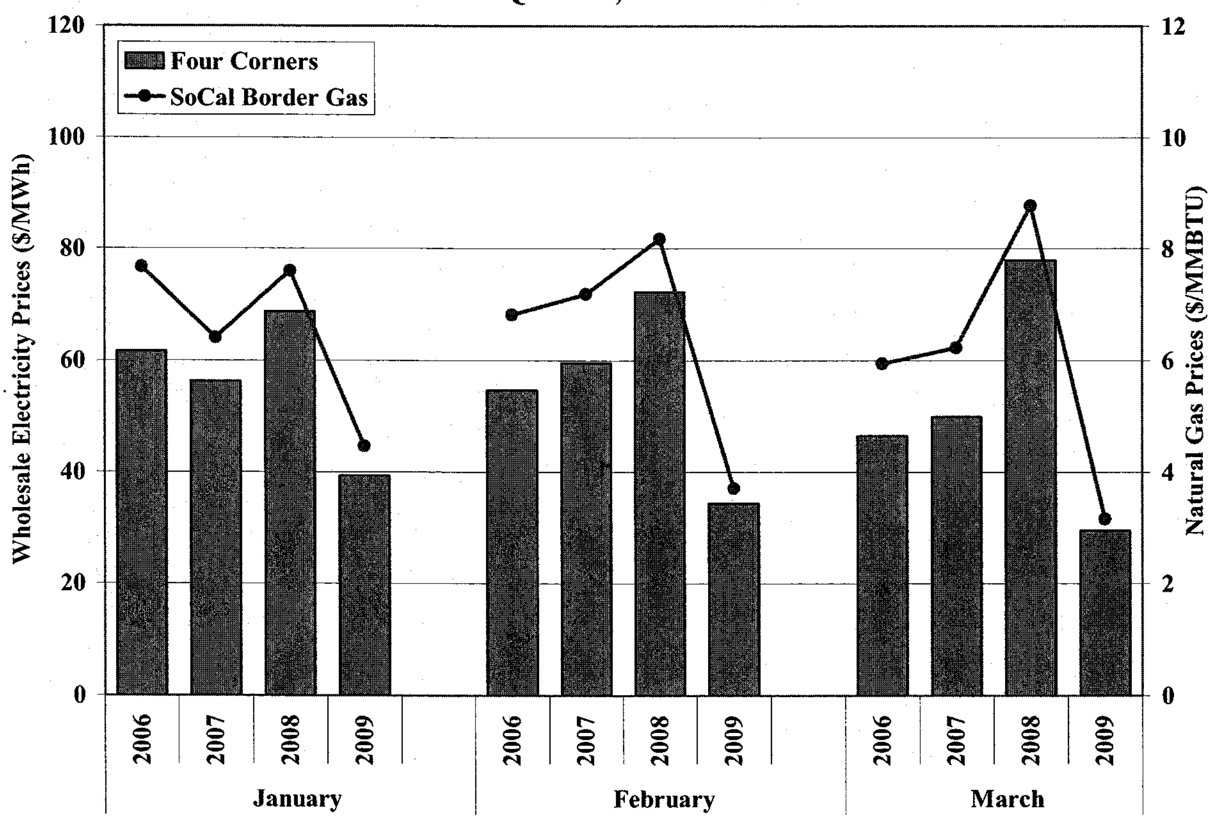
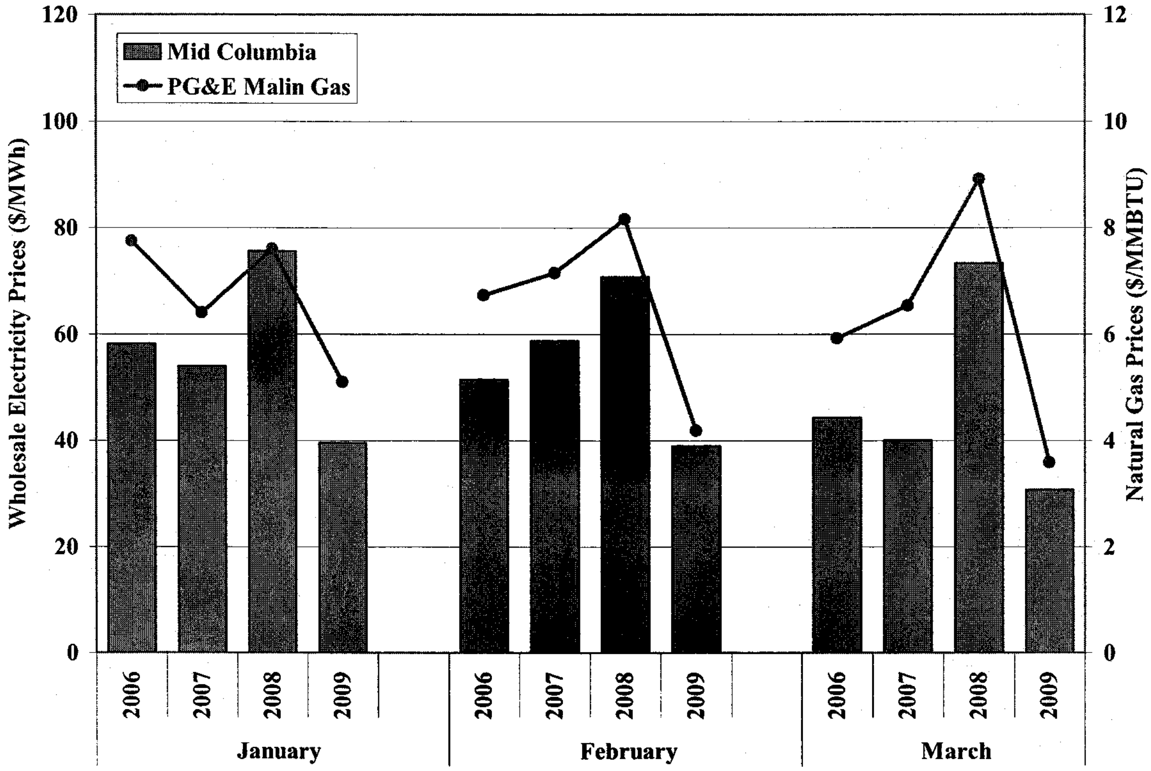


Figure 4: Northwest Trends in Monthly Electricity and Natural Gas Prices
First Quarter, 2006–2009



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 purchase activity for trades that delivered during the first 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
First Quarter of 2009

Redacted

Figure 5 shows that PAC's short-term [redacted] At a broad level, the fact that PAC's short-term [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 15,800 miles of transmission lines and approximately 10,000 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 did not invoke any UFRPs. However, it did implement 358 curtailments (including cases when curtailments were reversed) and schedule reductions totaling 9,648 MWh across fifteen 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.

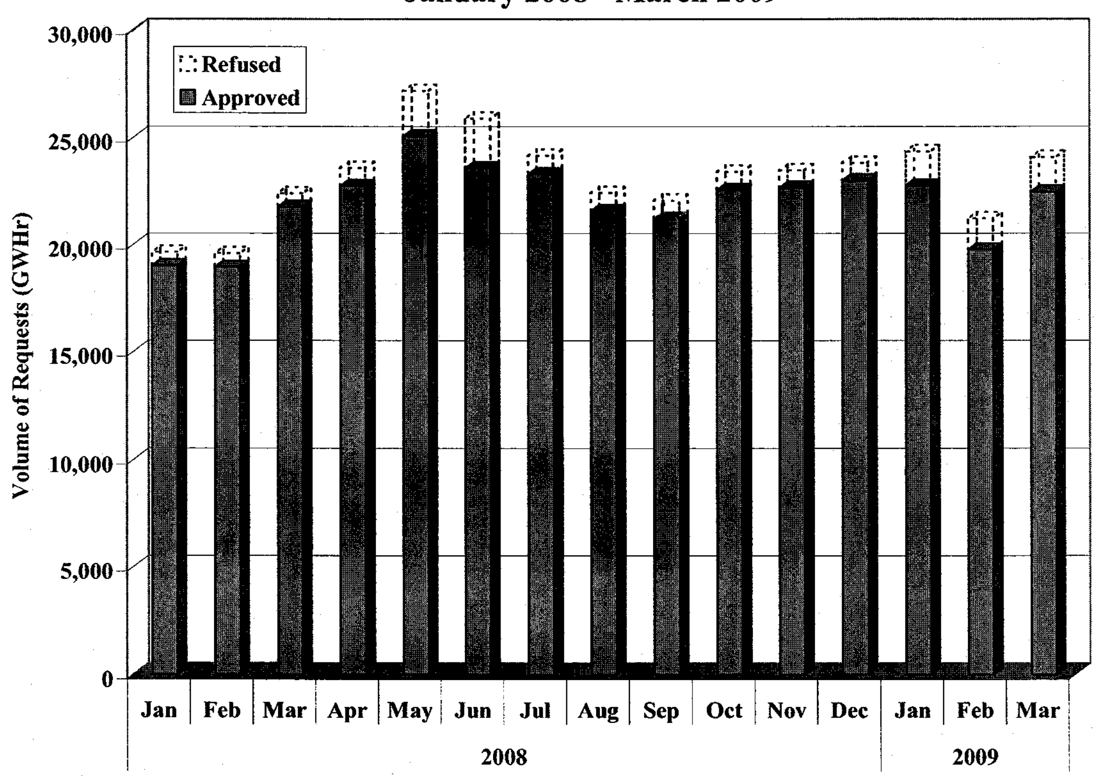
IV. TRANSMISSION ACCESS

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 January 2008 through March 2009 and summarizes the disposition of the requests.

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



The figure shows that the total volume of approved requests during the first quarter of 2009 was higher than the first quarter of 2008 and lower than the fourth quarter of 2008. The volume of refused service requests during the quarter was higher than the preceding quarter, averaging 1560 GWHr. Hence, the approval rate dropped from 96 percent for the fourth quarter of 2008 to 93 percent for the first quarter 2009. After further investigation, we found that the increase in refusals is due to 2699 GWHr of volume over the quarter that was requested prior to early 2007 for yearly service starting in 2009. Due to the way volumes are spread over time periods, this quarter is the first time that these refusals appeared in the exhibit. These refusals are not associated with the degree to which PAC has provided access to the transmission system during the period of study. 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

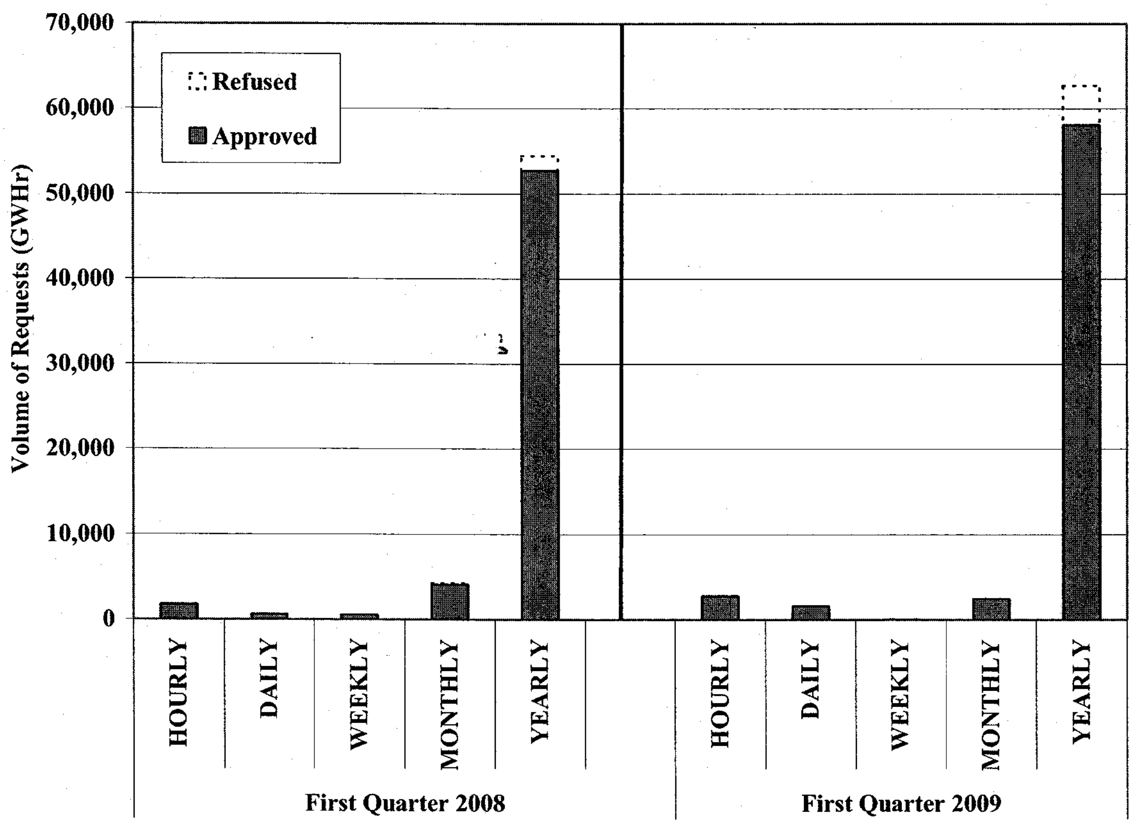


Figure 7 indicates an increase in the volume of approvals for all categories of service except for weekly and monthly. There was a substantial increase in the volume of refused yearly requests for the reasons noted above. For these cases in general, the customers did not continue with the application 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, operation of transmission assets in the third subsection, and PAC's transmission flows and congestion 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
First Quarter of 2009

Redacted

The volume weighted average daily sales prices ranged from [redacted]/MWh to [redacted]/MWh and average [redacted]/MWh. We say a day has a "beneficial curtailment" if PAC is a net seller at a

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.

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 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 January 24, January 27, January 28, February 10, February 14, February 16, February 20 and February 27 for closer examination. We chose these days because they had maximum daily effective market positions greater than or equal to [redacted] MW. 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 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.

To identify out-of-merit dispatch, we first estimate PAC's marginal cost curve or "supply curve".[7] We used incremental heat rate curves, fuel costs, and other variable operations and

[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.

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.

Figure 9 shows the estimated supply curve 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 Curve

Redacted

We used each day's estimated marginal cost curve as the basis for estimating PAC'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.

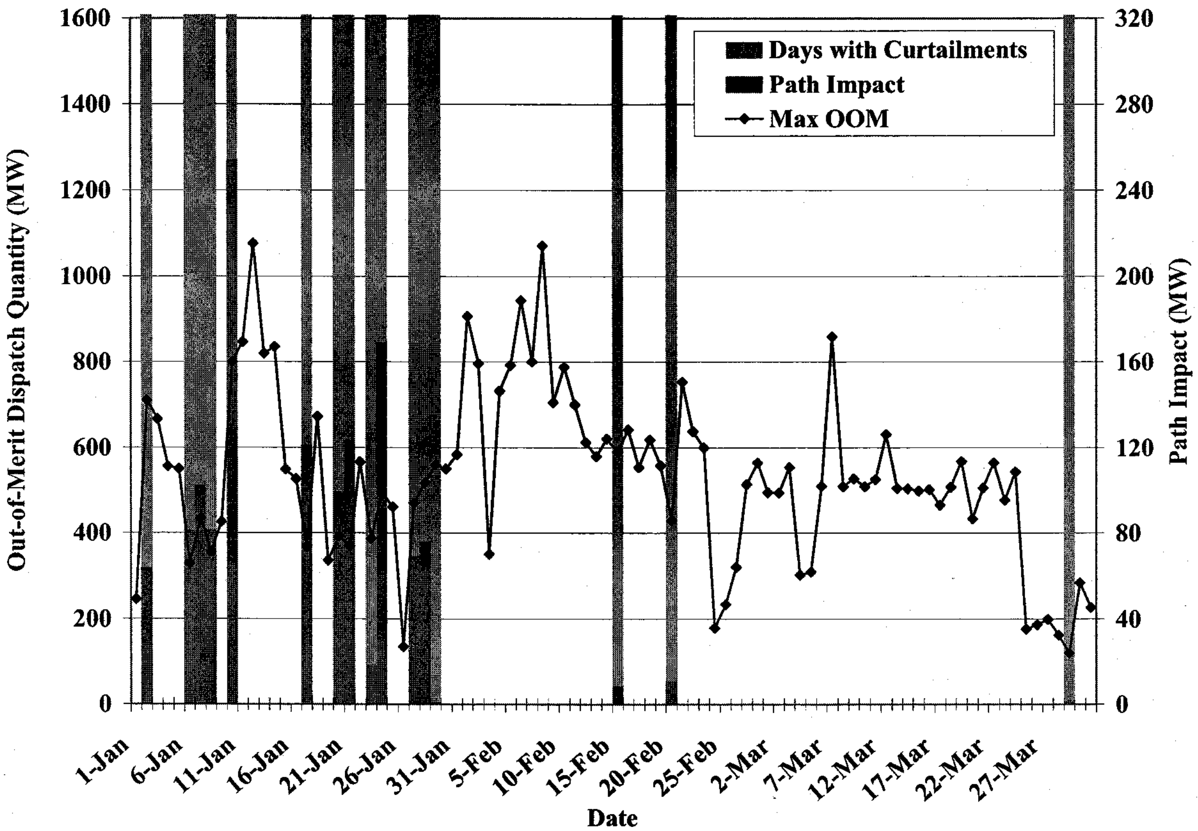
Other justifiable operating factors that cause the out-of-merit dispatch to be overstated are energy limitations and ancillary services. An example of an energy limitation is a governmental regulation limiting the number of hours a plant may run in a year. Since the unit is physically capable of producing, 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 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 when PAC curtailments were made on paths that were loaded by 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 figure also shows "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. The impact of out-of-merit dispatch was determined using generation shift factors[8].

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



As the figure shows, there were six days when out-of-merit dispatch was at least 400 MW and contributed at least 60 MW of increased flow over congested paths during the study period. We inquired further into these days and the days noted above based on PACs market positions and found the following.

- *January 2:* [redacted] was off line for a 36-hour unplanned outage to repair a [redacted]. This capacity was replaced with

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.

combined cycle generation in Utah, which caused high loadings and curtailments on Path C.

- *January 7:* [redacted] had a six-hour derating due to [redacted] had a one-hour derating due to [redacted] This capacity was replaced with combined cycle generation in Utah, which caused high loadings and curtailments on Path C.
- *January 10:* [redacted] was off-line for 58 hours to [redacted] was off-line for 51 hours to repair [redacted] The capacity from these two unplanned outages was replaced by combined cycle generation in Utah, which caused high loadings and curtailments on Path C.
- *January 24:* [redacted] was off-line to [redacted] This capacity was replaced by combined cycle generation in Utah, which caused high loadings and curtailments on Path C.
- *January 27 and 28:* [redacted] was off-line to [redacted] This capacity was replaced with combined cycle generation in Utah, which caused high loadings and curtailments on Path C. .

Our review of the days with high "Max Effect" identified in the purchases and sales section above determined that out-of-merit dispatch on those days had no impact on curtailed paths. Based on our review of the outage information in the disturbance reports, the operating logs, and information garnered from discussions with PAC personnel, we conclude that the aforementioned outages 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 seven transmission outage events that were associated with schedule curtailments that had curtailment deviations as presented in the next section below. We did not find any additional transmission outage that coincided with a

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

time when PAC had purchase and sales positions that may have benefited from congestion as presented above. We reviewed these seven outages and found the following:

- [redacted] This four-day forced outage commenced on [redacted] The purpose of the outage was to replace two fire damaged structures.
- [redacted] This twenty-hour forced outage started on [redacted] The line opened by automatic relay action. A broken ground wire was identified that may have contacted a conductor. After repair the circuit tested "good "and was placed back into service. The outage reduced transfer capacity between [redacted] leading to curtailments.
- [redacted] This ten-hour forced outage occurred [redacted] to repair a faulted line. The outage reduced transfer capacity and lead to curtailments on the [redacted]
- [redacted] This nine-hour maintenance outage occurred on [redacted] to replace the "x-arm" on a structure. The outage reduced transfer capacity and lead to curtailments on [redacted]
- [redacted] This six-hour unplanned outage occurred on [redacted] causing schedule curtailment on [redacted] The outage was taken to perform emergency repairs and cleaning of insulators (insulators become contaminated with bird droppings, which lead to ground faults).
- [redacted] This twenty-one-hour outage started on [redacted] causing schedule curtailments on [redacted] Broken insulators caused a three phase fault.
- [redacted] This three-hour outage occurred on [redacted] causing curtailments on [redacted] path in both directions. The line opened on automatic relay action twice, but latter tested good. The outage was caused by high winds in the area.

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. Analysis of Curtailments

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]

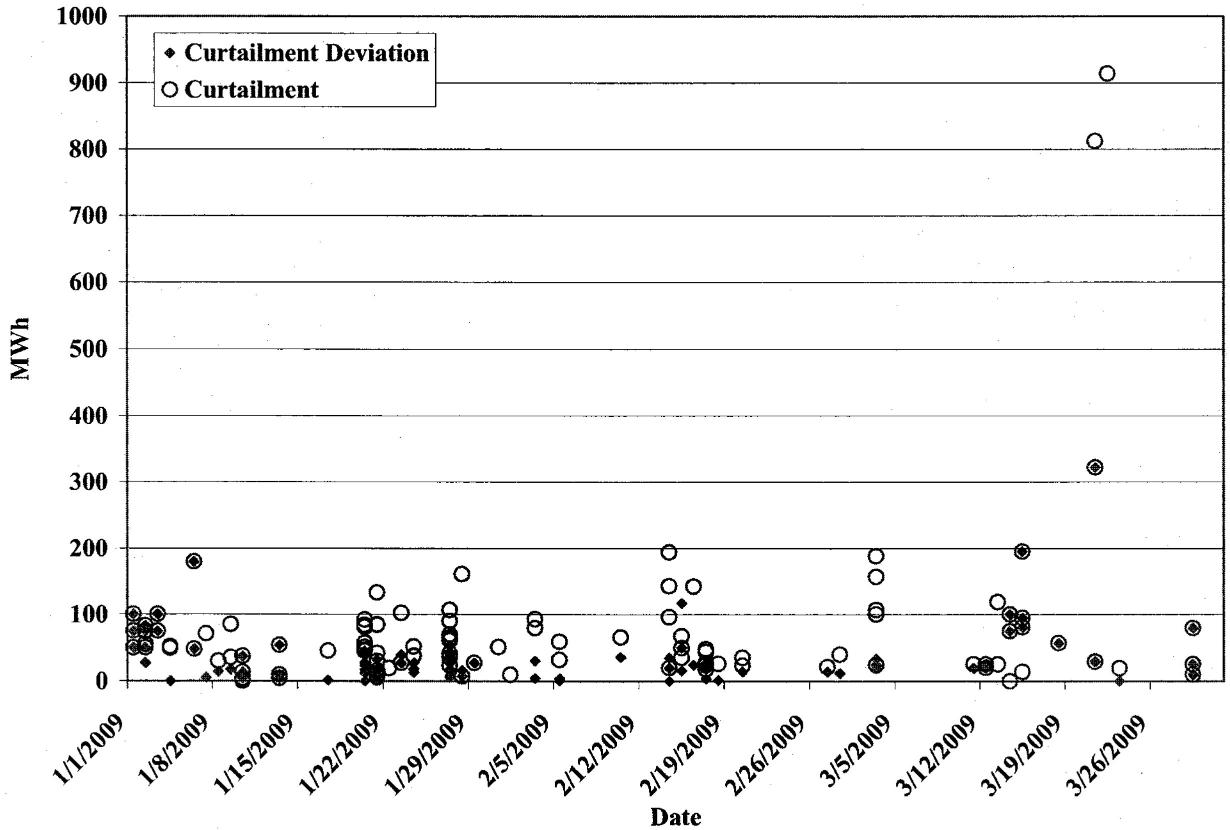
We analyzed the 15 paths where curtailments were initiated by PAC. We compare aggregated ex post net schedules to TTC. Ex post net schedules are the net schedules actually realized at the end of the operating hour. PAC makes the curtailment decision twenty minutes prior to the operating hour. However, 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. 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 11 shows the results of this analysis.

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 11: Curtailment and Curtailment Deviation
First Quarter of 2009



Over the quarter, 358 curtailments were implemented. Of these, 24 curtailments had at least a 75 MW deviation. We found that 22 of these curtailments were fully justified based on real-time operating conditions. These conditions include security events, transmission outages, and events where actual flows exceed line limits. For the remaining two curtailments,[12] we can see in retrospect that a smaller curtailment would have been sufficient. However, given that the flows that these curtailments are managing are influenced by loop flows, and that loop flows are difficult to predict, we find that having only two curtailments identified as overly conservative 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.

[12] Both these curtailments occurred on [redacted] The first was a 100 MW curtailment on [redacted] when at least a 24 MW curtailment was needed. The second was a 75 MW curtailment on [redacted] when at least a 39 MW curtailment was needed.

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.