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PUBLIC SERVICE COMPANY

REPORT OF EVENTS THAT LED TO CONTROLLED OUTAGES - PUBLIC SERVICE COMPANY OF COLORADO

DATE OF OCCURRENCE FEBRUARY 18, 2006

MARCH 13, 2006

A PORTION OF THIS DOCUMENT HAS BEEN FILED UNDER SEAL

Report of Events that Led to Controlled Outages
Public Service Company of Colorado
Date of Occurrence –February 18, 2006

Introduction

On Saturday February 18, 2006, Public Service Company of Colorado (Public Service) conducted controlled outages of electric customers from 8:48 a.m. to 10:18 a.m. MST. The controlled outages involved customers served on three groups of distribution feeders, involving approximately 100,000 customers in each group for approximately 30 minutes each. In addition, Public Service interrupted service to some of its interruptible retail customers and curtailed service to some of its wholesale customers, pursuant to contracts with these customers. The vast majority of Public Service retail customers experiencing controlled outages were restored to service in approximately 30 minutes. Ten of the Company's distribution feeders did not respond to the Company's signals to recommence service after the 30 minute controlled outages were over, and these feeders had to be manually reconnected. For customers on these ten feeders, customers lost electric service from 63 minutes to 240 minutes.

A controlled outage is a serious event. Public Service is conducting a thorough operational review to understand the events that led to the need for the controlled outage and to determine what processes should be employed to avoid a recurrence. This preliminary report provides the information that Public Service has collected to date about the circumstances and events that led to the controlled outages of February 18, 2006.

Background

A controlled outage is a temporary short-term procedure used by an electric utility to bring the utility's electric system load into balance with the utility's available supply of electricity. Controlled outages are undertaken in order to rectify an imbalance of generation and load that, if not corrected, could cause disturbances on the electric system that would "trip" generation and other electric facilities off-line, thereby causing even more extensive failures. The controlled outage executed by Public Service on February 18 successfully contained the imbalance problem such that Public Service was able to bring generation into balance with load within one and one-half hours, thereby minimizing electric system failures and inconvenience to customers.

To understand the events that led to the need for the controlled outage on February 18, it is important to understand how modern electric systems operate. Electricity is not stored -- it is produced real time to respond to the electric demands placed on the utility's system. Every time a consumer turns on or off a light or starts or turns off an appliance, the electric utility "ramps up" or "ramps down" electric generation connected to its "grid" to respond to that change in electric demand. As electric demand grows, more generators are started to respond to the increased demand. To save money and keep electric bills as low as possible, electric generation is started or "dispatched" by adding first the generation units that have the lowest incremental variable cost of producing the electricity, followed by more expensive generation as the system electric load grows.

On the Public Service system, the lowest incremental variable cost units are the renewable generating plants (hydroelectric and wind), followed by coal generating plants, then natural gas-fueled plants, and then plants burning fuel oil. Within the fleet of natural gas-fired generation, some newer gas plants are more efficient and have lower "heat rates" than the older plants; a plant with a lower heat rate takes less gas to produce a kilowatt-hour of electricity than a plant with a higher heat rate. Therefore, Public Service will dispatch natural gas-fired plants with lower heat rates prior to dispatching plants with higher heat rates.

Public Service does not own all of the generation that it uses to serve its customers' electric needs. Approximately 50% of the generation that is used to serve Public Service's retail load is owned by other companies – some is owned by utilities and some is owned by "independent power producers." When the generation capacity is owned by other companies, as is the case for most of the Colorado generating plants fueled with natural gas serving Public Service, Public Service contracts for and supplies the natural gas to the generators. Public

Service is dependent upon the other companies owning the generating plants to respond to Public Service's dispatch order to start and stop generation and to ramp up and down this generation. Public Service is also dependent upon these other companies to maintain their generation and to respond to forced outages of their generation.

In this report, there are references to many generation units that were involved in the events leading to the controlled outages of February 18. Of the generation plants mentioned, Public Service owns the following generation units: Fort St. Vrain, Valmont 5 and 6, Cherokee 4, Zuni 1 & 2, Fort Lupton, Cameo and Alamosa. Other companies own the other generation mentioned in this report. Exhibit No. 6 (attached) lists the generation owned by other companies that affected the events of February 18.

Electric System Planning

Since electricity cannot be easily stored and must be produced in real time, Public Service has sophisticated software programs that are used to predict the electric demand that its customers will place on its system, and to dispatch generation units to meet that instantaneous demand in the lowest cost manner. Long range planning is used to predict the generation capacity that must be built (or contracted) to serve electric load. Shorter term planning looks a day or two ahead to predict electric usage by hour and the availability of generating units. To protect against short-term shortfalls in electricity, Public Service has entered into agreements with neighboring utilities to share electric capacity in emergency situations. Public Service also has electricity traders who can acquire short-term electricity from other utilities and independent power producers – either to meet shortfalls in generation due to plant outages or to save money by buying electricity that is sold at a cheaper price than Public Service can produce it.

Public Service's electric traders purchase electricity on a monthly, daily and hourly basis. Electricity purchased on a daily basis is generally purchased and scheduled a day ahead of the time that it must be delivered and consumed, based upon the predicted availability of generating facilities for the next day and the predicted cost of running those facilities. Electricity needed for holiday weekends such as the Presidents' Day weekend of February 17–20 (Friday, Saturday, Sunday and Monday) is normally bought and scheduled on the prior Wednesday and Thursday mornings. Public Service's real-time traders can buy additional electricity "intra-day," if an unexpected generation outage occurs. But electricity cannot be bought instantaneously. Public Service's real-time traders can normally buy electricity for a given hour, so long as the purchase is consummated no later than 20 - 30 minutes prior to the commencement of the hour.

Gas System Planning

Public Service also buys gas to meet the needs of both its retail gas customers served by the Company's natural gas distribution system (the Local Distribution Company system or "LDC system") and the needs of the electric power plants that are fueled by natural gas. Public Service has limited gas storage capacity on its system. Public Service begins filling its share of the gas storage facility with natural gas in the summer months, when gas demand and prices are low, and then withdraws the stored gas during winter months when gas demand and prices are higher. But most of the gas needed for the LDC system and for the electric power plants is purchased on either a monthly or on a day-ahead basis. Limited "intra-day" purchases can be made, but are given lower deliverability priority by interstate gas pipelines than the gas that is purchased prior to the gas delivery day.

For gas to be used for electric generation purposes, gas delivery systems must maintain certain pressure levels. If the pressure on the gas pipelines drops too low, then electric power plants will either not start, or may be "tripped" off-line. Once the pressure in a gas pipeline gets too low, time is required to build back the pressures to acceptable levels.

To determine how much gas it needs to buy for both its LDC system (gas load) and the electric power plants, one of the major inputs to Public Service's analyses are weather forecasts. In the winter, the predicted "heating degree-days" derived from the weather forecast are the major determinant of the amount of gas that must be purchased for the LDC system. Weather also influences electric demand. Public Service employs a full time meteorologist to develop weather forecasts for use by the Company's gas buyers and electric traders. In addition, Company personnel continually monitor weather developments to adjust intra-day forecasts and the dispatch of power plants.

Reserves

In its planning, Public Service always maintains a significant "cushion" above its predicted electric and gas needs. In its long range planning, Public Service builds and contracts for 16% more generation capacity than it predicts it will need over the long term ("planning reserves'). On a continuous basis, Public Service also plans to maintain "operating reserves" (on-line generators that are not fully loaded, generation that can be started in ten minutes, and interruptible load) greater than the load requirements at any given point in time. In buying gas in the winter, Public Service buys No-Notice Service that allows the Company to draw gas from its contracted storage and have it delivered to its delivery system. In this way, should there be unanticipated events (colder weather, fuel interruptions or generating plant outages), there should be enough fuel and electric power to meet both the LDC gas demand and the electric power demand.

Summary of the problems that occurred on February 17- 18, 2006

On the days of February 17-18, a series of multiple and major unanticipated and interrelated events overwhelmed the electric and gas reserves that Public Service carries to handle these types of contingencies. In sum, colder than predicted weather drove up the demand for natural gas on the Company's LDC system. At the same time, a series of unanticipated generation plant outages (some weather-related, some not) of both Public Service-owned generation and generation owned by other companies drove up the demand for natural gas for the electric power plants. This increased gas demand occurred because of unexpected coal plant outages, and because of unanticipated outages of the more efficient (lower heat rate) gas-fired generating units, which were then replaced with less efficient (higher heat rate) gas-fired generating units that consumed more gas. Because this total demand for natural gas was substantially higher than had been predicted on a day-ahead basis, Public Service was limited in its ability to get enough gas for both its LDC system and its electric power plants.

Public Service's service territory was not the only region experiencing colder than predicted weather. This hampered Public Service's ability to purchase more gas. Further, because more gas was drawn from the pipelines than "nominated" the day before, gas pipeline pressures dropped to very low levels. The decrease is gas pipeline pressures made many electric power plants fueled by natural gas temporarily unavailable to Public Service.

As the problems caused by the unfortunate coincidence of these events became known late Friday and in the early hours of Saturday, Public Service's gas buyers and real time traders contacted suppliers of gas and electricity in the market to obtain alternative supplies. However, not enough gas could be purchased and pipeline pressures could not be maintained to allow Public Service and other companies to start available electric generation capacity. Public Service's real-time electric traders were able to purchase additional electricity from outside the Colorado Front Range to be delivered to the Public Service system, but not in time to avoid the need for the controlled outages to restore the balance between Public Service's electric loads and generation. This balance was restored by 10:18 a.m. Saturday, in large part due to the purchase of additional electricity from areas outside of the Front Range.

A graph of the required generation, and the forced outages of the generation units that led to the controlled outage, is provided as Exhibit No.12 (attached). As can be seen, between noon on February 17 and 8:48 a.m. February 18, Public Service lost approximately 3200 MW of the generation that Public Service anticipated would be available at the time that it bought both gas and electricity for the weekend of February 17-20. A detailed timeline of how these events unfolded is set forth in Exhibit No. 10 and is summarized below. In sum, the unanticipated sub-zero weather of February 17 and 18, combined with forced outages of 3200 MW of generation owned by Public Service and many other companies, led to a need for a short-lived temporary outage to bring the electric system back into balance. Public Service successfully executed the controlled outage and was able to keep the problems created by these events to a minimum.

Cold weather is not unusual in Colorado. Weather forecasts missing the cold weather are also not unusual in Colorado. However, the confluence of the unexpectedly cold weather arriving during the holiday weekend together with the many plant outages is unusual. Public Service is currently studying the changes that it should make to its planning and operating practices to react to similar multiple problems in the future so that controlled outages might be prevented.

Chronology of Important Actions

Discussed next is a description of how these events unfolded, on a day-by-day basis, from the perspective of the departments within Public Service that had to react to these unanticipated and problematic events. A detailed chronology of events, by hour, as seen from the perspective of Public Service's Gas Supply and Real-time Dispatch, is also set forth on Exhibit No. 10.

Wednesday February 15, 2006

Weather Forecasts

Public Service has prepared Exhibit 1 to show the forecasted hourly temperatures for February 17 and February 18 compiled by the Company's meteorologist from forecasts by the U.S. National Weather Service, weather.com, Accuweather, media forecasts, and other sources. Exhibit 1 shows how the forecasted temperatures for February 17 and 18 changed over the three-day period of February 15, 16, and 17. Public Service initially evaluated the gas needs for its electric power plants for February 17 and 18, based upon the Wednesday, February 15 forecast represented by the green line on Exhibit 1. The red line on Exhibit 1 shows the actual temperatures of the cold snap hitting the Colorado Front Range on February 17 and 18. As of Wednesday, February 15, the Company was forecasting a low overnight temperature for Friday night and Saturday morning of 6°F.

Electric Power Scheduling

On the morning of Wednesday, February 15, Public Service began the daily process of determining whether it should pre-schedule electric purchases for Friday February 17 and Saturday February 18. Exhibit No. 2 displays the electric load forecasted by hour for Friday and Saturday at various points in time and the actual load for those days. As of Wednesday, February 15, when Public Service analyzed whether to purchase pre-scheduled electricity, Public Service was forecasting the load represented by the green line on Exhibit 2. As of Thursday, February 16, when Public Service nominated gas for the electric power plants for the Presidents' Day Weekend, Public Service was predicting the load represented by the blue line on Exhibit 2. The actual electric load that occurred on Friday February 17 and Saturday February 18 is represented by the red line. The Company believes that this increase in electric load above the forecast was primarily driven by the colder-than-predicted weather that occurred on February 17 and 18. Exhibit No. 3 is a spreadsheet providing the supporting data for Exhibits No. 1 and 2.

The deviation of actual weather from forecasted weather for February 17 and February 18 was greater than Public Service normally experiences. Exhibit No. 4 is a spreadsheet that shows, in the left non-shaded columns, the percentage deviation, by day, from a day-ahead temperature forecast to an actual temperature value, for the months October 2005 through February 2006. As can be seen, the hourly average error in the day-head 24 hour temperature forecast over the past five months has been approximately 4.5 degrees F. However, for the period February 17-19, the day-ahead weather forecasts deviated from actual temperatures by 10.2 to 15.1 degrees F.

The shaded columns on Exhibit No. 4 show the hourly average error in Public Service's electric load forecasts for this same period. Over the past five months, the hourly electric load forecast has, on average, been within 2.5% of actual load. The electric load forecast errors for February 17 through 19 ranged from 3.1% to 3.5%. This data suggests that despite the large errors in the weather forecasts for Presidents' Day Weekend, Public Service's electric load forecast errors were within normal range.

Natural Gas Supply – Nominations

On Wednesday February 15, 2006, natural gas nominations for the weekend, for both electric power generation and for the LDC system, were not made. The standard practice in the natural gas industry is to nominate gas one day in advance of the scheduled flow date, except for weekends and holidays.

Thursday February 16, 2006

Weather Forecasts

On this day the weather forecasts were modified slightly to reflect the then-current forecast, shown as the dark blue line on Exhibit No. 1. On Thursday February 16, Public Service was forecasting a low overnight temperature for Friday night and Saturday morning of +1°F.

Electric Power Scheduling

The electric load forecast issued at 5:00 a.m. on Thursday February 16 for Friday and Saturday reflects small modifications from the prior forecast. This is shown as the dark blue line on Exhibit No. 2. This slight change in the forecast did not require Public Service to schedule additional electricity into its system for February 17 and 18.

Natural Gas Supply – Nominations

The gas supply requirements for the LDC system and electric generation were forecasted on Thursday morning February 16 for gas flow starting at 8:00 a.m. on February 17, 2006. Public Service's Gas Supply department forecasted the LDC sales load of 1,046,710 Dth, based on a forecast high temperature of 19 degrees and a low of 5 degrees, giving a mean temperature for the day of 12 degrees. This load forecast for the LDC system resulted in forecasted unutilized storage deliverability of 209,297 Dth, a substantial planning reserve (Exhibit No. 5 Table A).

The forecasted gas requirements for electric generation provided by Public Service's Electric Trading organization at approximately 7:00 a.m. were

245,500 Dth. Gas Supply purchased 262,402 Dth. These purchases, plus available storage withdrawal rights of 6,351 Dth, resulted in a total available supply of 268,753 Dth. This resulted in a predicted natural gas reserve margin of 23,253 Dth for electric generation on February 17. In addition, the ability to switch four generating units to fuel oil provided up to 116,767 Dth equivalent of additional reserves for a total predicted reserve margin of 140,020 Dth for Gas Day February 17. (Exhibit No. 5 Table B)

Friday February 17, 2006

Weather Forecasts

The weather forecasts were again modified slightly to reflect then-current information. The Friday weather forecast is shown as the turquoise line on Exhibit No. 1. As of Friday morning, Public Service was not forecasting any major difference in weather from the Company's Thursday forecast, upon which the gas nominations were made.

Although not reflected in the Company's forecast, the National Weather Service at 5:00 a.m. on Friday morning issued a warning that there may be below zero temperatures reached on February 17 and 18. The National Weather Service predicted –3°F, while the Company, using multiple weather forecasts, continued to predict a low of +1°F, a difference in temperature that the Company does not believe is material to the events that later unfolded. It was not until the Friday afternoon at approximately 3:30 p.m. that the National Weather Service predicted that temperatures could drop as low as -9°F in response to an arctic front that was slowly moving closer to the Denver area through northeast Colorado. Temperatures at Denver International Airport fell to -2°F by 6:00 p.m. Friday. Beginning after noon on Friday, DIA registered actual temperatures that were between 9°F to 20°F colder than forecasted. Public Service continued to monitor the effect of weather on electric and natural gas operations.

Electric Power Scheduling

Public Service's electric load forecast issued at 5:00 a.m. on Friday February 17 for Friday and Saturday reflects small modifications from the prior forecast. This is shown as the yellow line on Exhibit No. 2. There were no major changes to the availability of generation to meet load requirements, and no modifications to plant schedules were thought necessary. Referring to Exhibit No, 12, as of Friday morning, Public Service expected to have 7,600 MW of available generation capacity to serve electric load requirements (including reserves) of no more than 5,700 MW during February 17 and 18.

Reductions of Available Electric Capacity

As of Friday morning, Public Service's electric system had more than sufficient generating capacity available to meet forecasted load for the Presidents' Day Weekend and to meet all requirements for operating reserves. However, beginning shortly after noon on Friday, Public Service began experiencing an unprecedented series of generation plant outages, from both Public Service-owned generation and generation owned by other companies. A graph of these outages is portrayed on Exhibit No.12. To interpret this Exhibit, note that the red line shows the actual electric load plus required reserves that Public Service needed for each of the hours from noon Friday February 17 through 3:00 p.m. Saturday February 18. The solid black line at the top of the graph shows the level of generation capacity that Public Service believed would be available during these hours (capacity greatly in excess of the electric system load requirements plus reserves represented by the red line). A detailed discussion of the power plant outages is provided as Exhibit No. 10.

At approximately 12:38 p.m. on Friday, Rocky Mountain Energy Center (RMEC), a 640 MW low heat rate generation facility owned by an independent power producer, was forced off-line because of inlet filters plugging due to very cold temperatures. In response to the loss of this generation, Public Service dispatched (ordered the start-up of) Blue Spruce 2 on gas. Blue Spruce 1 had come on line earlier at 11:40 a.m. Blue Spruce units 1 and 2 replaced 300 MW of the generation capacity lost at RMEC. At 3:18 p.m., Blue Spruce units 1 and 2 (owned by an independent power producer) both tripped off-line due to gas valve malfunctions. Public Service dispatched its pumped storage unit Cabin Creek A to replace Blue Spruce. Realizing that additional coal-fired generation would be helpful, Cherokee 4, a 350 MW coal-fired generator owned by Public Service, was contacted to determine if it could delay its scheduled outage. At approximately 4:00 p.m., the Cherokee 4 shift supervisor advised that a previously scheduled outage of Public Service's unit Cherokee 4 would be delayed. Cherokee 4 remained in service, operating on coal, until approximately 4:00 a.m. Saturday, when it tripped off-line due to electrical problems in its control room. Also at approximately 4:00 p.m. on Friday, Public Service scheduled a 200 MW purchase from its affiliate Southwestern Public Service Company over the Lamar HVDC tieline. Public Service's Transmission Operations reviewed available generation resources and determined, at that point in time, that system reliability could be sustained with available resources.

At 5:32 p.m. on Friday February 17, Blue Spruce 1 returned to service, and remained on-line until 9:30 p.m., operating on fuel oil. Blue Spruce 2 was still unavailable due to water injection system problems. At 5:35 p.m., Public Service dispatched Manchief Unit 12, because it could draw gas directly from the Young gas storage facility instead of from the gas pipeline. At 7:56 p.m., Manchief Unit 12 tripped due to the extreme cold and was essentially unavailable until ambient temperatures increased 9°F.

Then at 11:54 p.m., Fort St. Vrain (FSV) lost its steam boiler, resulting in a loss of 295 MW. This steam turbine uses the waste heat from three gas-fired combustion turbines, thereby producing electric power without needing any incremental natural gas. At that time, the three FSV combustion turbines remained in service producing 437 MW. Following the loss of the FSV steam boiler, Public Service's Gas Control allowed Public Service's Real-time Dispatch to dispatch the Plains End power plant on natural gas for a short while. Plains End is composed of 20 reciprocating engines, owned by an independent power producer.

Natural Gas Supply-Operations

The gas supply requirements for the LDC system and electric generation were forecasted on Friday morning February 17 for gas flow starting at 8:00 am on February 18, 2006. Public Service's Gas Supply department forecasted the

LDC sales load of 942,039 Dth based on high temperature of 18 degrees and a low of 6 degrees for a mean of 12 degrees. This load forecast for the LDC system forecasted unutilized storage deliverability of 313,968 Dth. (Exhibit No. 5 Table E).

Based on the forecasted natural gas requirements provided by Electric Trading at approximately 7:00 am on February 17 for Gas Day February 18 of 265,000 Dth, Gas Supply purchased 266,739 Dth. These purchases, plus planned storage withdrawal of 10,000 Dth, resulted in a total available supply of 276,739 Dth. This resulted in a forecasted natural gas reserve margin of 11,739 Dth for electric generation on February 18. In addition, the ability to switch four facilities to fuel oil provided up to 116,767 Dth equivalent of additional reserves for a total forecasted reserve margin of 128,506 Dth for Gas Day February 18 (Exhibit No. 5 Table F).

In addition, at approximately 6:30 a.m., the Gas Supply department revised the LDC sales load forecast for Gas Day February 17 to be 1,181,670 Dth based upon a high temperature of 15 degrees and a low temperature of minus 7 degrees or a mean of 4 degrees. Based on this revised forecast, the LDC system was forecasted to have 74,337 Dth of unutilized storage deliverability. In addition, Colorado Interstate Gas Company (CIG) authorized 93,520 Dth of storage overrun for a total predicted reserve margin of 167,857 Dth (Exhibit No. 5 Table C). There were no changes to the gas supply requirements for electric generation for gas day February 17 made the morning of February 17; therefore no revisions to the gas supply nominations for electric generation were made on Friday morning.

At approximately 12:45 p.m. on Friday, Public Service's Gas Control department communicated to Gas Supply that electric generation was over-burning its daily gas supply entitlements by 73,000 Dth (262,402 + 73,000 = 335,402). This over-burn resulted from the loss of the lower heat rate gas units, which were replaced with less efficient, higher heat rate gas generation, as well as from the higher-than-predicted electric loads. In response, Gas Supply purchased 31,543 Dth of Intra-Day 2 supply. Intra-Day 2 supply cannot "bump" (take priority over) scheduled gas already confirmed in previous cycles by the pipeline, Colorado Interstate Gas Company. Therefore, only 23,373 Dth of the 31,543 Dth purchased by Public Service actually flowed to Public Service due to pipeline cuts. Intra-Day 2 gas supplies start flowing at 8:00 p.m. (MST). The 31,543 Dth that was purchased by Gas Supply was all the gas that Gas Supply could locate in the marketplace Friday afternoon, due in part to cold temperatures across the mid-continent and due in part to many potential gas sellers leaving the office early for the upcoming holiday weekend. These changes are reflected in the increased amount of daily spot purchases shown on Exhibit No. 5 Table D, as compared to the original plan for Friday February 17 shown in Exhibit No. 5 Table B. In addition, Exhibit No. 5 Table D shows the updated gas supply forecast made at 1:00 p.m. of Friday February 17; it also reflects the storage and fuel oil volumes as of that time.

Natural Gas Control

Public Service's Gas Control department is responsible for the operation of Public Service's gas pipelines. Gas Control redirected gas from Rocky Mountain Energy Center (RMEC) to other power plants around 1:15 p.m., due to the outage at RMEC that had occurred. At approximately 2:30 p.m., Gas Control called Gas Supply, concerned that the electric plants were projected to exceed their gas nominations. Gas Supply agreed to look for additional gas in the market and requested Public Service's Real-time Dispatch department to commence burning fuel oil to minimize gas burns at electric power plants. Gas Control also suggested that the Manchief power plant be ramped up, using natural gas from Young Storage. Gas Control informed Gas Supply at 3:00 p.m. that, at the current burn rate, electric generation would exceed their nominations by 93,000 Dth. This would put the electric system in a situation of using 69,000 Dth of unauthorized overrun gas.

Colorado Interstate Gas Company (CIG) was notified of Public Service's plan to overrun its nominated gas supplies and CIG gave no indication that it could not supply the additional gas. At 5:34 p.m., CIG contacted Gas Control regarding gas pressure problems, expressing concern about CIG's own ability to keep pipeline pressure up. At 5:39 p.m., Gas Control contacted Real-time Dispatch to inform them of current pressure issues with the Public Service and CIG systems and that Real-time Dispatch should consider buying power or burning oil. Around 6:19 p.m., Gas Control contacted Colorado Interstate Gas to request pipeline compression at Fort Lupton; CIG informed Public Service that the Fort Lupton compressors were already on.

Saturday, February 18, 2006

Weather Status

After midnight, the actual temperatures were between 12°F to 15°F colder than forecasted. Public Service continued to monitor the effect of weather on electric and natural gas operations. As shown on Exhibit No. 12, as late as 7:00 a.m. Saturday, Public Service still had sufficient generation available to meet the load and reserve requirements, despite the much colder than predicted temperatures.

Reductions of Available Electric Capacity

Exhibit No. 6 reports the availability status of generation units owned by other companies with output contracted to Public Service as of Saturday morning at approximately 9:00 a.m. Many of these plants had become unavailable to Public Service due to the cold weather. For example, the combination of extremely cold weather and changing wind direction created inlet air problems on combustion turbines.

At 12:35 a.m., Valmont 5, a 160 MW coal-fired unit owned by Public Service, tripped off-line due to frozen controls. Gas Control agreed to Plains Ends' operation on natural gas for a little while. Plains End operated on natural gas from 12:49 a.m. until 1:24 a.m.

At 4:10 a.m. Fort St. Vrain tripped Combustion Turbine No. 4, taking 150 MW out of service. Also at 4:10 a.m., Cherokee 4 tripped off-line due to electrical problems in its control room, removing 340 MW from service. At 4:15 a.m., Plains End came on-line, responding to the loss of Cherokee 4, and operated until 5:25 a.m. Gas Control allowed the Public Service Fort Lupton turbines to start up on natural gas to meet electric spinning reserve needs, but required these turbines to be operated at minimum output levels due to low gas pressures in the pipeline. At 4:24 a.m., Public Service's Cabin Creek pumped storage unit started generating due to a loss of reserves. At 4:51 p.m., Real-time Dispatch requested the start up of one unit at Blue Spruce on fuel oil. At 5:14 a.m., Gas Control ordered Plains End off-line due to natural gas system reliability concerns due to low pressures. At 5:20 a.m., Blue Spruce 1 was back on-line using fuel oil. Blue Spruce 2 failed to start until 1:00 p.m.

At 5:18 a.m., Thermo Carbonic and Thermo Industries reported that they lost natural gas flow to their generation units. At 5:28 a.m., the output of the Thermo facility was reduced by 200 MW, with a further reduction of an additional 33 MW at 6:35 a.m.

At 5:35 a.m., Real-Time Dispatch asked Gas Control which generation facilities could be supported by the gas system at that time. Gas Control reported that Zuni 1 & 2 (97 MW) and Arapahoe 5, 6 & 7 (132 MW) could be supported on natural gas. Due to low gas pressures in their areas, Valmont 7 & 8 (88 MW), Brighton 1&2 (152 MW), Brush 4 (140 MW), and Plains End (113 MW) could not be supplied natural gas until further notice. Gas Control further informed Real-time Dispatch that the Fort Lupton turbines (90 MW) could not be supported on natural gas much longer. Real-time Dispatch called to start up the Zuni and Arapahoe units. At 5:47 a.m., the Fort Lupton units were switched to fuel oil.

At 6:14 a.m., Valmont 6 became unavailable due to gas pressure limitations. Gas Control informed Real-time Dispatch that it would have to purchase electricity from the market. Real-time Dispatch told Gas Control that absent additional generation resources, the electric system would be deficient and a system emergency declaration may be necessary. Real-time Dispatch informed the electric traders to buy 600 MW at any price for Hour-Ending 8:00 a.m. (electricity to be delivered to Public Service from 7:00 to 8:00 a.m.). At 6:15 a.m., Real-time Dispatch discussed with the Lookout Control Area Operator all available options including: purchasing energy, curtailment of the interruptible customers, and starting up diesel generation. At 6:55 a.m., Gas Supply asked

Real-time Dispatch to switch all generation facilities that were capable of burning fuel oil from burning natural gas to burning fuel oil due to low gas pressures. At 6:59 a.m., it was determined that the Zuni plant would not be able to come on-line until Saturday afternoon.

At 7:01 a.m., Public Service's Control Area Operator at Lookout Center contacted Real-time Dispatch to discuss the need to purchase electricity from other suppliers at any price. At 7:11 a.m., Gas Control informed Real-time Dispatch that its could not support the start-up of the 640 MW Rocky Mountain Energy Center due to low gas pressures. At 7:30 a.m., Gas Control informed Real-time Dispatch that the Limon generation (76 MW) could not be started due to low gas pressures.

As the magnitude of the generation deficiency became apparent, the Real-time power traders were able to increase electricity purchases for hours-ending (HE) 8 a. m. through 12 p.m. Public Service was purchasing 428 MW for HE 7. These purchases were increased to 757 MW for HE 8, 931 MW for HE 9, 1048 MW for HE 10, 1109 MW for HE 11, and 986 MW for HE 12. These purchases were made for reliability reasons and were made irrespective of price.

At 8:40 a.m., Front Range Power Company lost 480 MW of combined-cycle generation due to frozen water valves, 204 MW of which was under contract to Public Service. The loss of Front Range Power was the final event leading to the necessity to shed Public Service customer firm load, because Public Service's units could not cover the shortfall created by the loss of Front Range Power's units due to low gas pressures in the geographic areas of the otherwise available generation capacity.

<u>System Operations (Lookout Center)</u>

Public Service's Transmission Operations, in concert with the Rocky Mountain Reliability Coordinator (RMRC), declared an Energy Emergency Alert Level 1 at 7:16 a.m. on February 18. In conjunction with this alert, a request was made to all entities that may have surplus electric generating capacity via the Western Electricity Coordinating Council (WECC) internal network. The California

ISO and others contacted Public Service's Real-time traders with offers of energy beginning at 7:39 a.m..

Public Service's Transmission Operations, in concert with the RMRC, initiated a firm load curtailment of approximately 400 MW at 8:50 a.m. in response to the loss of the Front Range Power Company generation. Transmission Operations then contacted Public Service's Distribution Control Center to inform them of the load curtailment and the controlled outages began. At 8:51 a.m., an Energy Emergency Alert Level 3 was declared.

Distribution Control Center

Once made aware of the controlled outages, at approximately 8:50 a.m., Public Service's Distribution Control Center followed the Outage Management Protocol and contacted Public Service's Call Center. The Call Center was told planned outages were expected all day and that it was not clear how many customers would be impacted or what the expected duration of outages would be.

However, the controlled outages did not last all day; they lasted only one and one-half hours. A total of 188 distribution feeders were involved in the controlled outage load shed. Exhibit No. 7 sets forth the feeders that were taken out of service and the outage duration on each feeder. The average load for each feeder interrupted was approximately 6.2 MW, with a total interruption of 1193 MW. The controlled outages were segmented into three load groups, each of which cycled through a predetermined rotation of individual feeders with an interruption duration of approximately 30 minutes in length. Ten feeders included in this controlled outage rotation were not restored to service after the 30-minute outage, either because they did not respond to SCADA signals to reclose, or because they experienced a control circuit failure, or because of degraded lubrication due to low ambient temperatures. The ten feeders with greater than 30 minutes of outage are set forth on Exhibit No. 8 and are highlighted on Exhibit No. 7; these feeders resulted in extended outages for 20,507 customers of between 63 minutes and 247 minutes.

For the ten feeders that did not automatically restore service after the controlled outage, Public Service had to send crews to the feeders to fix the problems. The Distribution Control Center was adequately staffed on February 18 to handle field switching for these ten feeders. However, field personnel had to avoid interfering with the controlled outages that were in progress and had to prevent unnecessary overloads on reenergized feeders.

Public Service has a list of "excepted" feeders that are not affected by controlled outages, if possible. Highly Confidential Exhibit No. 9 is provided with this report under seal to the Staff of the Colorado Public Utilities Commission and to the Colorado Office of Consumer Counsel. These feeders serve customers where the loss of electric power could cause serious public health and/or public safety problems. Public Service makes every effort to exclude these feeders from controlled outages.

<u>Natural Gas Supply – Operations</u>

On the morning of February 18, the Gas Supply department revised the LDC sales load for the February 18 gas day to be 1,147,930 Dth, based on a high temperature of 10 degrees and a low temperature of 2 degrees or a mean of 6 degrees. Because of the severe reduction in gas system line pack (gas in the pipeline) experienced on gas day February 17, an additional 128,600 Dth of intra-day spot gas was purchased for gas day February 18; however, due to pipeline cuts, only 124,597 Dth of this purchase flowed to Public Service. *See* Exhibit No. 5 Table G. Gas Supply was also notified of continuing over-burns by electric generation at approximately 6:40 a.m., and was able to purchase 7,700 Dth of Intra-day 1 gas supply for gas day February 18 (Intra-Day 1 gas flows start at 4:00 p.m.) and made over-run gas available from Young Storage for Manchief. The revised system setup for electric generation Gas Day February 18 is summarized in Exhibit No. 5 Table H.

<u>Natural Gas Control</u>

Throughout Saturday morning, Gas Control was in frequent communication with Real-time Dispatch. Gas Control informed Real-time Dispatch that generation using natural gas must be used sparingly, if at all. At

4:00 a.m., CIG contacted Gas Control and requested that Public Service reduce its power plant gas load. At 5:14 a.m., Gas Control called Real-Time Dispatch and informed them of the need to get Plains End off-line immediately. At 5:16 a.m., Gas Control contacted Real-time Dispatch to inform them that a critical gas pressure situation existed. Gas Control asked Real-time Dispatch to buy wholesale power off the grid. At 5:19 a.m., Kerr McGee and Encana, two gas processing plants in the DJ Basin in Weld County, Colorado, went out of service, adversely affecting Public Service's gas supply. At 5:35 a.m. Real-time Dispatch contacted Gas Control to discuss which gas-fired units could be supported, given the problems with low gas pipeline pressure.

At 6:06 a.m., Gas Control and Natural Gas Services made the decision to notify the interruptible gas sales customers to cease using gas and to call an Operational Flow Order for the day affecting all transportation customers. An Operational Flow Order requires gas transportation customers (customers who purchase their gas from a company other than Public Service but have their gas transported by Public Service) to match nominations with burns, whether by purchasing additional gas supply or by reducing gas burns. At 6:23 a.m., Gas Control denied Thermo Carbonics' request to pull gas due to dropping pressure in the pipelines. At 7:22 a.m., Gas Control called CIG, inquiring whether Beaver Creek had any extra gas. CIG told Gas Control that none existed and that CIG's line pack was dropping.

At 7:53 a.m., Natural Gas Services issued an Operational Flow Order (OFO) to customers in the Front Range gas delivery area. At 9:02 a.m., Natural Gas Services revised the OFO, adding the Denver-Pueblo gas delivery area.

Conclusions and Lessons Learned

The Interrelationship Between Gas Demands On The Electric And LDC Systems During Extremely Cold Weather Is Not Well Understood.

As shown by the series of events just discussed, during the period of Friday February 17 through Saturday February 18, personnel at Public Service followed established procedures to try to maintain reliable electric and natural gas services in the face of unprecedented numerous power plant outages. The numerous power plant outages caused a demand for higher-than-expected natural gas usage for electric generation during a period of extremely cold weather and high heating demands. This unusual confluence of events caused a significant strain on the gas pipeline system, dropping gas pipeline pressures to levels that could not support both the electric generation and the Local Distribution Company system. But, except for one area affecting about 150 customers, Public Service maintained deliveries to its natural gas customers on the LDC system during this period. Public Service personnel also succeeded in controlling the imbalance between electric load and generation on the electric system through the three controlled outages, thereby preventing this imbalance from causing even more equipment failures or from affecting neighboring utility systems. The controlled outages were well executed and were short-lived; for the most part customers were restored to full electric service within approximately 30 minutes. Public Service employees did well to contain what could have been a far worse situation when numerous power plants were unexpectedly forced off-line at the same time that Front Range Colorado had high gas demands due to very cold weather.

The communications among Public Service Company's departments responsible for operating the electric and natural gas systems were frequent and responsive. The actions taken during the critical time period in the early hours of Saturday morning were appropriate for the known status of each of the gas and electric systems as events occurred. Other than problems with the interruptible program and communications with customers discussed later, Public Service personnel followed established procedures and reacted appropriately as the crisis unfolded.

This operational review reveals, however, that the following critical interrelationship is not well understood -- the interrelationship between: 1) the increased gas demand on the LDC system from colder than predicted weather; and 2) the increased gas demand that can occur on the electric system from multiple power plant outages during cold weather, particularly increased gas demands resulting from outages of low heat rate gas plants. During February 17 and 18, the Public Service system experienced drops in gas pipeline pressures that it had never experienced before, preventing Public Service from starting up and using available natural gas-fired generation. During February 17 and 18, relatively new efficient natural gas plants owned by independent power producers (RMEC, Blue Spruce, Front Range Power Company, Manchief) were stressed for the first time by extremely cold weather and tripped off-line for various reasons. It is very important that the problems that can be created by cold weather, for both the electric and gas systems, and their interrelationship, be thoroughly studied.

During this critical time period, due to the greater than predicted gas demands, the natural gas supply and delivery systems were not capable of meeting the needs of both the LDC system and the electric generators, due to insufficient pressures that resulted on certain parts of the gas pipeline delivery system. Exhibit No. 11 is a graphic display of the CIG and Public Service natural gas system pressures from February 16 through 18. During Friday night into early Saturday morning, pressures in certain areas were dropping significantly below alarm levels. Since a problem of this magnitude had not occurred before, Public Service's procedures did not lay out the specific steps that needed to be taken by all Company departments in response to this event. Yet even though Public Service personnel were facing this large a problem for the first time, by using established procedures they were able to contain the problem very quickly.

Public Service's Gas Control department promptly and continually notified Public Service's Real-time Dispatch that low gas pressures would prevent the start-up of certain generation units. Generation units that could burn fuel oil as well as natural gas were switched to fuel oil to alleviate the pressure problems. The Manchief generators that could be supplied directly from gas storage were started to alleviate dropping pipeline pressures.

Public Service's Gas Supply department promptly bought additional gas supplies when the over-burns and under-forecasts became apparent. However, cold weather affected a broad geographic region, many gas sellers had departed early due to the holiday, and not all the gas that Public Service purchased could be delivered.

Public Service's Real-time Dispatch department successfully increased electric energy purchases, switching from the rules requiring only economic purchases to a "buy-at-any-price" signal at 6:14 a.m., as soon as the effect of the gas pressure problems on the availability of Public Service's generation capacity was fully known and the status of the Zuni and Arapahoe units could be determined. More purchased electric energy was delivered to Public Service's system beginning at 7:00 a.m. and even more electric energy was scheduled and delivered beginning at 8:00 a.m. Unfortunately, when the Front Range Power Company units (located south of Colorado Springs) tripped out-of-service at 8:48 a.m. due to frozen water valves, depriving Public Service of 204 MW at a time when gas pipeline pressures were too low to restart other available generation capacity, Public Service was left with no choice but to call an Energy Emergency Alert and commence controlled outages.

Public Service's System Operations (Lookout Center) performed the controlled outages very well, restoring the system to balance within one and one-half hours. Public Service's Distribution Control Center repaired all feeders within four hours.

This operational review did reveal, however, that Public Service personnel, facing an unprecedented situation, may not have fully understood the gravity of the situation right away. Because these specific simultaneous problems affecting many different departments within the Company had not occurred before, Public Service personnel in each department may not have had a full understanding of the issues facing other departments. For example, it is unclear whether the Gas Control department had a full appreciation of constraints experienced by Real-time Dispatch to obtain sufficient electric power to meet load and reserve requirements. It is also unclear whether the Real-Time Dispatch department had a full understanding of the gas supply and pressure problems with which Gas Control was dealing. For example, at 4:29 p.m. on Friday February 17, in response to an inquiry from Real-time Dispatch, Gas

Control confirmed that a per Dth penalty should be factored into the economic purchase avoided cost signal used by the real-time traders. Real-time Dispatch interpreted that message to mean that physical natural gas was readily available, but that a small penalty premium would need to be added to the price of the gas. In the past, such a penalty had not been a signal that gas would be in short supply and not available at any price.

Public Service will study the potential problems that can be caused to its LDC system and its electric system by cold weather and will determine how established procedures need to be altered to take into account the overlapping problems that led to the controlled outages on February 18.

Interruptible Customers

At 6:37 a.m. Saturday morning, the customers under Public Service's less than ten minute notice Interruptible Service Option Credit (ISOC) program were interrupted by System Operations at Lookout Center. However, not all customers were fully interrupted. The one-hour-notice customers dropped approximately 1.8 MW of load in response to the interruption notice. This interruptible program did not work as intended and Public Service is continuing to investigate what happened and why the interruptible program did not work smoothly.

Public Service also curtailed some, but not all, wholesale customers whose loads are curtailable under their wholesale contracts with Public Service. Approximately 413 MW of long-term wholesale sales were taking place during the time of the controlled outages. Under the contracts with Western Area Power Administration, the Municipal Energy Association of Nebraska, Arkansas River Power Authority and Aquila, Public Service has certain defined rights to curtail wholesale loads during times of system emergencies. Public Service is continuing to investigate the circumstances surrounding which wholesale customers were curtailed and when they were curtailed.

Even if the interruptible programs had worked as designed, there would still have been a need for controlled outages, given the significant total loss of generation capacity by 8:40 a.m. on Saturday when the Front Range Power Company generation tripped off-line and given the low gas pressures at that time in the pipelines. Nevertheless, Public Service will investigate how to improve its procedures for effecting permissible interruptions (of both wholesale and retail load) during system emergencies.

External Communications

Public Service is also reviewing how well and timely the Company informed its customers and the general public about the controlled outages. External communications were made by the Company's Media Relations department and by the Call Centers.

Media Relations

In general, it appears that the press releases from Media Relations issued during this time period were accurate, but about two to three hours too late. Media relations personnel communicated several times with the various media, but press releases weren't issued until later in the morning of Saturday February 18. Public Service is reviewing its protocols on how information should be timely supplied to Media Relations from various departments within Public Service. It is important that the first press release and all subsequent direct contacts with media representatives correctly convey the expected duration of the controlled outages for each group of customers.

Customer Care – Call Centers

Between 8:45 a.m. and 9:00 a.m. on Saturday February 18, the Xcel Energy Call Centers started receiving calls from Colorado, the volume of which grew to nearly 450 times more than expected for a Saturday morning. Public Service customers expressed displeasure with the inability to speak with their utility company. Between 8:45 a.m. and 10:30 a.m. on Saturday, over 250,000 callers received a busy signal from Xcel Energy. During that same time frame, nearly 20,000 calls connected to the Call Centers. Between 8:30 a.m. and 10:30 a.m. on Saturday, over 2,200 calls were handled by the Xcel Energy agents. In response to the massive call volumes, Xcel Energy brought in additional agents to the Call Centers. However, because of the number of customers affected by the controlled outage, no significant improvement in the number of customers receiving busy signals occurred until after the outages were restored to service.

The Call Centers had received messages from the Distribution Control Center stating that they expected to have planned outages all day, but they were not sure how many customers would be impacted or what the expected duration of the outages would be. This was inconsistent with the correct information that the controlled outages were expected to be of thirty minutes duration for groups of approximately 100,000 customers each. The Call Centers were not accurately informed of the extent of the outages until 9:45 a.m., but even then the Call Centers were only told that 100,000 customers were affected and no other details were mentioned. It wasn't until 11:20 a.m. MST that Media Relations informed the Call Centers that the outages had affected three groups of 100,000 customers for a duration of 30 minutes each. By this time, the controlled outages were over.

Other communications from Media Relations to the Call Centers continued through the late Saturday morning and early afternoon. The customized message provided to callers by the Call Centers related to the controlled outages read as follows: "Xcel Energy is aware of the outage in the Denver metro and surrounding area, which has been caused by equipment failure. We are currently assessing the damage and will provide an approximate restoration time as one becomes available." This message was incomplete and did not provide customers with information that the outage was under the control of the Company or that its duration was expected to be thirty minutes. Improvement in communication to customers concerning the nature and extent of outages is clearly necessary.

Recommendations

Public Service has identified the events on February 17 and February 18 that led to the controlled outages. While controlled outages are important tools to limit problems on electric utility systems, Public Service is committed to improving its processes so that if similar circumstances should arise in the future, Public Service personnel will be able to react to these circumstances in a way that would avoid controlled outages. To that end, Public Service will be studying the following issues over the next 90 days:

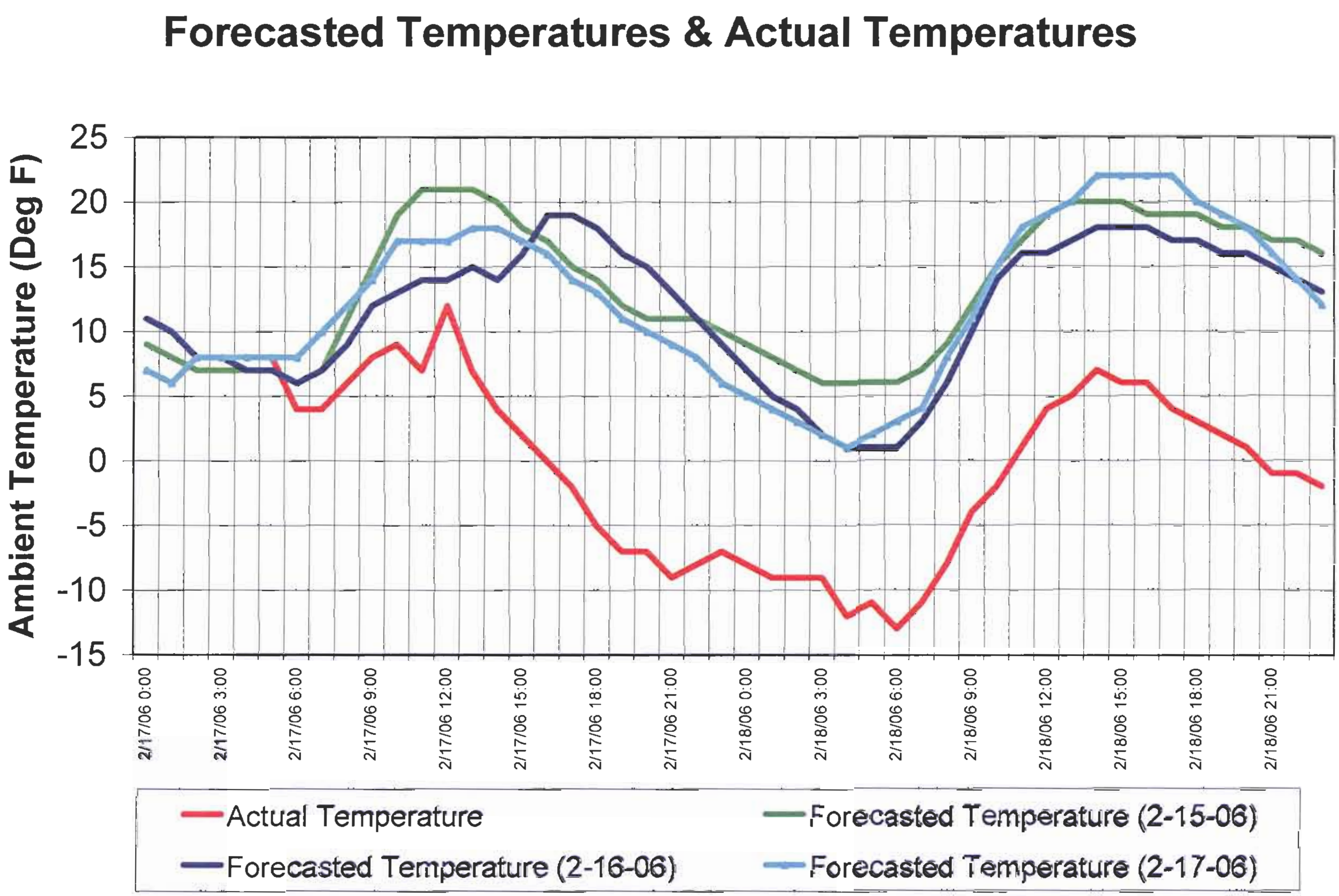
- Public Service will investigate whether normal protocols related to gas control, gas supply, economic dispatch, energy trading, reserve levels, and planning criteria should be altered to provide more "cushion" to respond to extremely cold weather conditions and extremely hot weather conditions. The Company is already investigating additional gas storage opportunities. Public Service will investigate how to align and integrate various operations to deal with cold weather, hot weather and special events, with the objective to prevent system degradation to avoid activating more serious emergency procedures.
- Public Service will study how to improve communication among various Company departments so that each department has an accurate understanding of the interrelationships between the operations that each department controls. As part of this effort, Public Service will investigate whether there are barriers to full communication of operational problems, resulting from interpretations of federal Codes of Conduct, that need to be addressed. Public Service will develop operating protocols for Gas Control, Real Time Dispatch/ Electric Trading, and Gas Supply so that during elevated operations each department has an accurate understanding of how problems need to be evaluated and communicated to other departments, so that all employees have an accurate understanding of how their respective responsibilities interact.
- Public Service will thoroughly investigate problems that arose, both internal to the Company and with customers, in exercising Public Service's right to interrupt its retail and wholesale customers who have elected to take interruptible service.
- Public Service will work with its generation suppliers to investigate the causes of power plant failures over the Presidents' Day weekend to determine how similar plant failures can be avoided. The Company has

fully investigated the operation of its own generation fleet during the time recounted in this report.

- Public Service will study how to improve internal communication channels so that its Media Operations and Call Center personnel have accurate and timely information. Public Service will investigate what technology can be used to provide more accurate information to customers calling to report outages.

EXHIBIT NO. 1

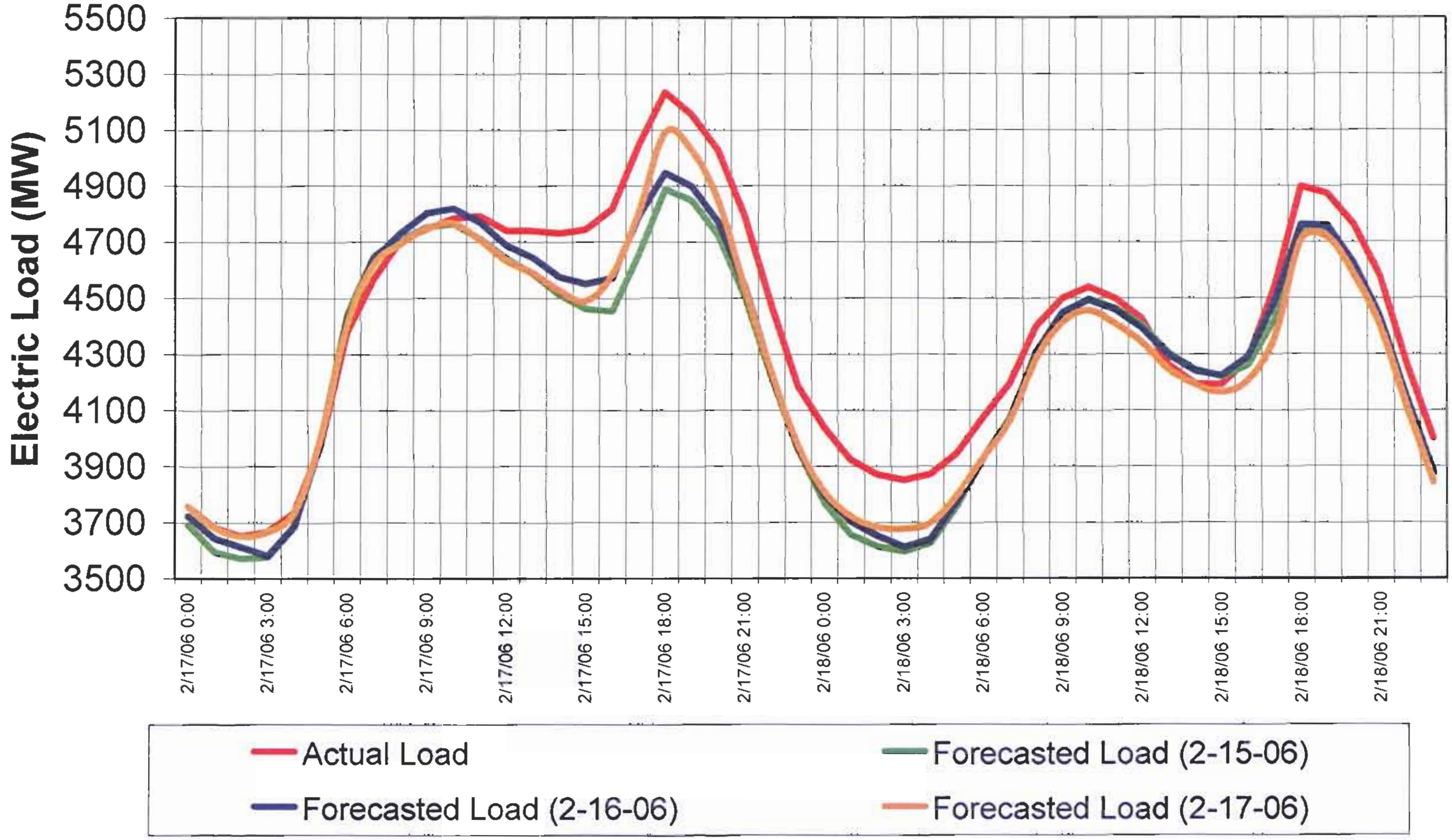
Exhibit No. 1



*Forecasted Loads due to President's Holiday

EXHIBIT NO. 2

Forecasted & Actual Electric Load



*Forecasted Loads due to President's Holiday

EXHIBIT NO. 3

Public Service Company of Colorado
Load Forecast

FORECAST ISSUED WEDNESDAY 5AM

	LOAD FORECAST		TEMPERATURE	
	Feb. 17 Fri.	Feb. 18 Sat.	Feb. 17 Fri.	Feb. 18 Sat.
HE 1	3692	3770	9	9
HE 2	3595	3657	8	8
HE 3	3572	3614	7	7
HE 4	3576	3597	7	6
HE 5	3684	3628	7	6
HE 6	3989	3758	7	6
HE 7	4442	3929	6	6
HE 8	4653	4073	7	7
HE 9	4707	4302	11	9
HE 10	4754	4447	15	12
HE 11	4766	4498	19	15
HE 12	4714	4464	21	17
HE 13	4642	4406	21	19
HE 14	4588	4306	21	20
HE 15	4513	4247	20	20
HE 16	4463	4220	18	20
HE 17	4455	4261	17	19
HE 18	4658	4426	15	19
HE 19	4889	4745	14	19
HE 20	4849	4744	12	18
HE 21	4725	4609	11	18
HE 22	4510	4412	11	17
HE 23	4220	4143	11	17
HE 24	3960	3882	10	16

Public Service Company of Colorado
Load Forecast

FORECAST ISSUED THURSDAY 5AM

LOAD FORECAST CHANGE FROM WEDNESDAY FORECAST

	Feb. 17 Fri.	Feb. 18 Sat.	Feb. 17 Fri.	Feb. 18 Sat.	Fri	Sat
HE 1	3724	3799	11	7	32	29
HE 2	3644	3704	10	5	49	47
HE 3	3613	3653	8	4	41	39
HE 4	3582	3613	8	2	6	16
HE 5	3688	3642	7	1	4	14
HE 6	3987	3777	7	1	-2	19
HE 7	4422	3931	6	1	-20	2
HE 8	4641	4063	7	3	-12	-10
HE 9	4731	4308	9	6	24	6
HE 10	4804	4450	12	10	50	3
HE 11	4820	4493	13	14	54	-5
HE 12	4772	4459	14	16	58	-5
HE 13	4689	4394	14	16	47	-12
HE 14	4645	4298	15	17	57	-8
HE 15	4576	4241	14	18	63	-6
HE 16	4552	4224	16	18	89	4
HE 17	4573	4291	19	18	118	30
HE 18	4794	4489	19	17	136	63
HE 19	4947	4762	18	17	58	17
HE 20	4899	4757	16	16	50	13
HE 21	4773	4622	15	16	48	13
HE 22	4546	4427	13	15	36	15
HE 23	4232	4138	11	14	12	-5
HE 24	3966	3872	9	13	6	-10

Public Service Company of Colorado
Load Forecast

FORECAST ISSUED 5AM FRIDAY

	Feb. 17 Fri.	Feb. 18 Sat.	Feb. 17 Fri.	Feb. 18 Sat.	LOAD FORECAST CHANGE FROM THURSDAY 5AM FORECAST Fri	Sat
HE 1	3759	3811	7	5	35	12
HE 2	3683	3724	6	4	39	20
HE 3	3653	3684	8	3	40	31
HE 4	3668	3679	8	2	86	66
HE 5	3736	3700	8	1	48	58
HE 6	4001	3798	8	2	14	21
HE 7	4406	3931	8	3	-16	0
HE 8	4621	4064	10	4	-20	1
HE 9	4693	4284	12	8	-38	-24
HE 10	4750	4414	14	11	-54	-36
HE 11	4767	4456	17	15	-53	-37
HE 12	4710	4409	17	18	-62	-50
HE 13	4634	4343	17	19	-55	-51
HE 14	4590	4248	18	20	-55	-50
HE 15	4529	4193	18	22	-47	-48
HE 16	4491	4165	17	22	-61	-59
HE 17	4583	4207	16	22	10	-84
HE 18	4806	4361	14	22	12	-128
HE 19	5091	4708	13	20	144	-54
HE 20	5029	4718	11	19	130	-39
HE 21	4851	4584	10	18	78	-38
HE 22	4541	4397	9	16	-5	-30
HE 23	4237	4111	8	14	5	-27
HE 24	3977	3844	6	12	11	-28

Public Service Company of Colorado
Load Forecast

	ACTUAL LOAD VALUES		FRIDAY LOAD DEVIATION FROM ACTUAL			SATURDAY LOAD DEVIATION FROM ACTUAL		
	Feb. 17 Fri.	Feb. 18 Sat.	WED FCST	THUR FCST	FRI FCST	WED FCST	THUR FCST	FRI FCST
HE 1	3759	4041	-67	-35	0	-271	-242	-230
HE 2	3683	3926	-88	-39	0	-269	-222	-202
HE 3	3653	3872	-81	-40	0	-258	-219	-188
HE 4	3668	3853	-92	-86	0	-256	-240	-174
HE 5	3736	3874	-52	-48	0	-246	-232	-174
HE 6	3975	3948	14	12	26	-190	-171	-150
HE 7	4379	4075	63	43	27	-146	-144	-144
HE 8	4570	4196	83	71	51	-123	-133	-132
HE 9	4705	4400	2	26	-12	-98	-92	-116
HE 10	4749	4500	5	55	1	-53	-50	-86
HE 11	4784	4540	-18	36	-17	-42	-47	-84
HE 12	4794	4500	-80	-22	-84	-36	-41	-91
HE 13	4742	4427	-100	-53	-108	-21	-33	-84
HE 14	4741	4263	-153	-96	-151	43	35	-15
HE 15	4732	4194	-219	-156	-203	53	47	-1
HE 16	4746	4192	-283	-194	-255	28	32	-27
HE 17	4818	4281	-363	-245	-235	-20	10	-74
HE 18	5046	4541	-388	-252	-240	-115	-52	-180
HE 19	5235	4898	-346	-288	-144	-153	-136	-190
HE 20	5156	4872	-307	-257	-127	-128	-115	-154
HE 21	5029	4762	-304	-256	-178	-153	-140	-178
HE 22	4796	4575	-286	-250	-255	-163	-148	-178
HE 23	4477	4265	-257	-245	-240	-122	-127	-154
HE 24	4188	4002	-228	-222	-211	-120	-130	-158

EXHIBIT NO. 4

PSCO DAY AHEAD* TEMPERATURE VERIFICATIONS:
HOURLY AVERAGE ERROR (F)

	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06
DAY 1	4.3	4.3	3.3	5.8	3.4
DAY 2	7.0	4.5	5.0	7.1	2.5
DAY 3	4.8	5.3	5.4	9.5	1.9
DAY 4	11.3	1.8	3.0	3.6	3.9
DAY 5	2.8	5.8	3.7	4.9	1.6
DAY 6	4.0	3.7	7.7	2.5	2.6
DAY 7	2.2	5.0	4.3	4.8	4.3
DAY 8	4.3	4.8	4.2	3.7	4.9
DAY 9	10.6	3.0	3.5	2.8	7.6
DAY 10	12.1	3.2	4.5	4.8	2.0
DAY 11	2.9	2.8	3.7	5.6	2.4
DAY 12	7.3	4.9	2.0	3.0	3.9
DAY 13	2.9	6.6	1.5	3.6	2.7
DAY 14	4.7	4.3	4.0	3.2	4.9
DAY 15	2.4	2.6	3.1	2.0	3.5
DAY 16	4.6	1.8	1.9	2.8	2.9
DAY 17	7.1	6.4	2.5	5.8	10.4
DAY 18	2.6	4.0	4.6	5.5	15.1
DAY 19	3.5	4.0	4.7	3.3	10.2
DAY 20	2.2	3.2	9.1	5.0	5.3
DAY 21	3.5	2.8	7.4	1.6	5.0
DAY 22	2.7	3.9	7.4	2.6	3.3
DAY 23	4.0	5.3	3.4	2.2	3.5
DAY 24	3.8	2.1	2.5	2.9	3.8
DAY 25	2.6	4.5	6.9	3.8	6.5
DAY 26	1.8	7.2	4.4	5.1	3.2
DAY 27	1.8	3.7	7.4	3.0	9.7
DAY 28	2.1	6.7	4.2	3.8	4.1
DAY 29	6.8	3.5	5.2	6.0	
DAY 30	5.5	3.2	3.3	4.2	
DAY 31	2.7			4.6	
MONTHLY AVERAGE	**4.5**	**4.2**	**4.5**	**4.2**	**4.8**

DAY AHEAD* LOAD FORECAST ERROR
24 HOUR MAPE (MEAN ABSOLUTE PERCENT ERROR)

Oct-05	Nov-05	Dec-05	Jan-06	Feb-06
1.9%	2.1%	1.0%	5.8%	1.3%
2.7%	2.6%	1.9%	4.6%	1.2%
1.4%	1.4%	1.7%	5.1%	1.2%
7.2%	1.4%	1.2%	1.5%	1.6%
1.1%	1.5%	1.2%	1.0%	2.1%
1.3%	1.3%	2.0%	1.5%	0.7%
3.4%	1.7%	3.2%	1.3%	1.1%
4.5%	1.2%	1.2%	2.0%	0.9%
6.1%	1.9%	2.3%	2.6%	2.0%
8.1%	1.6%	1.2%	2.2%	2.4%
2.3%	1.3%	1.7%	1.8%	1.3%
1.2%	2.1%	1.6%	2.7%	1.6%
1.8%	4.4%	2.5%	2.4%	1.1%
2.0%	4.4%	2.1%	1.9%	1.2%
1.9%	1.5%	2.6%	2.2%	2.1%
3.2%	1.1%	1.3%	1.5%	1.1%
3.4%	4.0%	2.8%	2.3%	3.5%
1.6%	1.6%	2.2%	1.7%	3.1%
1.6%	1.4%	1.4%	1.6%	3.2%
0.6%	3.8%	4.5%	2.1%	2.1%
1.1%	2.7%	2.1%	1.3%	1.3%
0.7%	1.4%	1.8%	2.1%	2.6%
1.6%	1.1%	2.2%	1.4%	1.6%
2.4%	2.0%	3.7%	0.7%	1.0%
0.8%	3.2%	2.8%	1.0%	1.6%
0.7%	4.4%	7.7%	1.1%	1.4%
0.7%	4.6%	3.3%	0.8%	2.2%
0.9%	5.8%	1.3%	1.1%	1.1%
1.7%	1.2%	2.2%	1.5%	
6.4%	0.6%	1.4%	1.0%	
4.2%			0.7%	
2.53%	**2.30%**	**2.28%**	**1.94%**	**1.70%**

EXHIBIT NO. 5

Natural Gas Supply

Exhibit No. 5

Table A — Gas supply plan prepared on Thursday - February 16, 2006 (Gas Day February 17)

Forecast Sales Load (Forecast made @ 7:00 am)	1,046,710
Baseload Supplies	376,358
Roundup Storage	30,000
Young Storage - Maximum	187,000
NNT Storage - Maximum	662,649
Daily Spot Purchases	0
Net Gas Supply long<Short>	**209,297**
Authorized Storage Over-run	0
Net Reserves Long <Short>	**209,297**

Table A

Table B

Forecast Generation Load (Forecast made @ 7:00 am)	245,500
Baseload Supplies	183,000
Young Storage	6,351
Daily Spot Purchases	79,402
Authorized Storage Over-run	0
Net Gas Supply long<Short>	**23,253**
Fuel Oil Back-up (MMBtus)	116,767
Net Reserves Long <Short>	**140,020**

Table B

Table C — Gas supply plans prepared on Friday - February 17, 2006 (Gas Day February 17)

Forecast Sales Load (Forecast made @ 7:00 am)	1,181,670
Baseload Supplies	376,358
Roundup Storage	30,000
Young Storage - Maximum	187,000
NNT Storage - Maximum	662,649
Daily Spot Purchases	0
Net Gas Supply long<Short>	**74,337**
Authorized Storage Over-run	93,520
Net Reserves Long <Short>	**167,857**

Table C

Table D

Forecast Generation Load (Forecast made @ 1:00 pm)	335,402
Baseload Supplies	183,000
Young Storage	6,351
Daily Spot Purchases	110,945
Authorized Storage Over-run	38,649
Net Gas Supply long<Short>	**-3,543**
Fuel Oil Back-up (MMBtus)	77,840
Net Reserves Long <Short>	**74,297**

Table D

Table E — Gas supply plans prepared on Friday - February 17, 2006 (Gas Day February 18)

Forecast Sales Load (Forecast made @ 7:00 am)	942,039
Baseload Supplies	376,358
Roundup Storage	30,000
Young Storage - Maximum	187,000
NNT Storage - Maximum	662,649
Daily Spot Purchases	0
Net Gas Supply long<Short>	**313,968**
Authorized Storage Over-run	0
Net Reserves Long <Short>	**313,968**

Table E

Table F

Forecast Generation Load (Forecast made @ 7:00 am)	265,000
Baseload Supplies	183,000
Young Storage	6,351
Daily Spot Purchases	83,739
Authorized Storage Over-run	3,649
Net Gas Supply long<Short>	**11,739**
Fuel Oil Back-up (MMBtus)	116,767
Net Reserves Long <Short>	**128,506**

Table F

Table G — Gas supply plans prepared on Saturday - February 18, 2006 (Gas Day February 18)

Forecast Sales Load (Forecast made @ 7:00 am)	1,147,930
Baseload Supplies	376,358
Roundup Storage	30,000
Young Storage - Maximum	187,000
NNT Storage - Maximum	662,649
Daily Spot Purchases	128,600
Net Gas Supply long<Short>	**232,674**
Authorized Storage Over-run	59,437
Net Reserves Long <Short>	**296,114**

Table G

Table H

Forecast Generation Load (Forecast made @ 7:00 am on Friday)	265,000
Baseload Supplies	183,000
Young Storage	6,351
Daily Spot Purchases	91,439
Authorized Storage Over-run	38,649
Net Gas Supply long<Short>	**54,439**
Fuel Oil Back-up (MMBtus)	116,767
Net Reserves Long <Short>	**171,206**

Table H

EXHIBIT NO. 6

Public Service Of Colorado
Plant Status Report 2-18-2006

Exhibit No. 6

Contract	Facility	Total Winter Net Capacity (MW) (Per Contract)	Fuel		Status on the morning of 2/18/2006
Basin Electric Power Coop #3	LRS #2 & #3	29	Coal		Fully available
Basin Electric Power Coop 1&2	LRS #2 & #3	125	Coal		Fully available
Black Hills, Wyoming (Wygen)	Wygen One	60	Coal		Fully available
Platte River Power Authority	Rawhide	30	Coal		Unavailable (Rawhide was at 50% of capacity since earlier in the week)
Tri-State Gen & Trans Assoc. 2	LRS #2 & #3, Craig #1, #2 & #3	100	Coal		Limited to about 48 MW (Craig 1 and 3 offline for forced outages)
Tri-State Gen & Trans Assoc. 3	LRS #2 & #3, Craig #1, #2 & #3	75	Coal		Limited to about 35 MW (Craig 1 and 3 offline for forced outages)
Tri-State Gen & Trans Assoc. 5	LRS #2 & #3, Craig #1, #2 & #3, Nucla	100	Coal		Limited to about 53 MW (Craig 1 and 3 offline for forced outages)
PacifiCorp	System	176	Mix, primarily coal		176 MW prescheduled beginning HE 08 on 2/18
Black Hills Colorado (Arapahoe)	Arapahoe #5, #6 & #7	132	Gas	PSCo	On-line by 06:30 on 2/18 and ramped-up at about 09:00 on 2/18.
Tri-State G & T Assoc - Brighton	Brighton	154	Gas	PSCo/CIG	Gas Control said gas not available to start units 2/18 at 05:30
Brush 1 & 3 (CPP)	Brush 1/3	75	Gas	PSCo	Plant unavailable (not in warm standby mode)
Brush 2 (BCP)	Brush 2	68	Gas	PSCo	Operating normally
Brush 4D (CEM)	Brush 4D	130	Gas	PSCo	Gas Control said gas not available to start units 2/18 at 05:30 (boiler was drained on 2/17 because not expected to run)
Blue Spruce Energy Center	BSEC	310	Gas/Oil	CIG/PSCo	Gas pressure/control problem tripped units at 15:20 on 2/17, restarted on fuel oil for evening peak on 2/17, Unit #2 was unavailable due to water injection system problems from about 06:00 on 2/18 to about 13:00 on 2/18
Fountain Valley	Fountain Valley 1-6	247	Gas	CIG	Unit #1 unavailable from about 04:30 on 2/18 to about 12:56 on 2/18 due to cold oil and cold stator alarms (initially shut down previous evening due to frozen NOx water line). Other 5 units were available.
Front Range Power Company	Front Range	204	Gas	CIG	Unavailable from 08:30 on 2/18 to about 14:00 on 2/18 - steam turbine exhaust condensate freezing
Black Hills, Wyoming (Gillette)	Gillette	40	Gas	?	Not prescheduled for the morning of 2/18.
Tri-State G & T Assoc - Limon	Limon	73	Gas	CIG	Gas not scheduled for Limon
Manchief Power Company LLC	Manchief	301	Gas	CIG	Unit #12 unavailable 2/17 19:56 to 2/18 10:18 due to inlet filter freezing and emissions
Plains End LLC	Plains End	113	Gas	PSCo	Gas Control said gas not available to start units 2/18 at 05:30 until 12:20 on 2/18
Rocky Mountain Energy Center	RMEC	601	Gas	CIG	Unavailable due to inlet filter freezing from 2/17 at 12:30 to 12:30 on 2/19
Thermo Cogen	Thermo Cogen	272	Gas	PSCo/CIG/Duke	2 of 5 jets unavailable from about 06:30 on 2/18 to about 11:30 on 2/18 after tripping due to gas pressure issues.
Thermo Monfort	Thermo Monfort	32	Gas	?	Operating normally
Thermo Power & Electric	UNC Greeley	69	Gas	Duke	Offline after Friday peak
Black Hills Colorado, LLC (Valmont)	Valmont #7 & #8	81	Gas	PSCo	Gas Control said gas not available to start units 2/18 at 5:30 until 12:45 on 2/18
Small QF and Hydro	Many	35	Assorted		
Colorado Green Holdings LLC	Lamar Wind	162	Wind		Zero - no wind
Distributed Generation Systems Inc.	Ponnequin Ph 1	5	Wind		Zero - no wind
Ridge Crest Wind Partners LLC	Peetz Wind	30	Wind		Zero - no wind
Spring Canyon Energy LLC	Spring Canyon	60	Wind		Zero - no wind
	Total	*3888*			

EXHIBIT NO. 8

Feeders That Failed
To Properly Operate

Exhibit No. 8

Substation	Feeder #	Failure cause		
		Control circuit	Degraded Lubrication	SCADA
BANCROFT	1816			
BOULDER TERMINAL	1357			
GREENWOOD	1436			
GREENWOOD	1438			
HAVANA	1937			
LEGGET	1322			
LITTLETON	1738			
NCAR	1557			
NORTH	1425			
SEMPER	1953			

EXHIBIT NO. 9

Highly Confidential Information
Highly Confidential Exhibit No. 9 has been filed under seal

EXHIBIT NO. 10

Title: February 18, 2006 Controlled Load Interruption – Gas Supply, Electric Trading

Incident Summary:

Time Line:

Date	Time	Action/ Activity	Who	Comments/ Analysis
02/15/06	~05:00:00	Electric load forecast is completed for Friday Feb 17th – Saturday Feb 18th due to WECC pre-schedule calendar. This load forecast is used to establish a unit commit plan, and to develop Inc/Dec price signals	Meteorologist	On Wednesday, the electric load forecast for Saturday Feb 18th HE 7 = 3929 MW. The actual load for Feb 18th HE 7 = 4075 MW. .
02/15/06	06:53:00	The PSCo system Inc-Dec prices for Feb 17th – 18th are completed and distributed to electric traders	Trading analyst	No forward daily electric purchases are made. Power prices are expected to be lower during the hourly market on the 17th.
02/16/06	~05:00:00	Electric load and weather forecast is updated for Friday through Sunday	Meteorologist	The Saturday morning temperature is reduced from Wednesday's forecast of a low of 6 degrees to a low of 1 degree. The electric load forecast increased for Friday by an average 41 MW for each hour of the 24-hour period.
02/16/06	~06:00:00	Prepare load forecast for LDC natural gas requirements for Gas Day February 17th (08:00 Friday – 08:00 Saturday)	Manager Gas Supply (PSCO)	The LDC load forecast was 1,046,710 based on Weather.com's forecasted average temperature of 12 degrees. This load forecast resulted in unutilized storage deliverability of 209,297 Dth for gas day Feb. 17, therefore no spot gas supplies were purchased.
2/16/06	~07:00:00	The Trading Analyst provides the forecasted generation gas needs to Gas Supply for Gas Day February 17th.	Sr. Gas Buyer – PSCO Electric	The forecasted generation gas requirements for Feb 17 were 245,500 Dth. The Company planned to meet this demand through: *183,000 Dth under monthly baseload contracts *6,351 Dth of firm withdrawal rights from Young storage. *79,402 Dth of spot gas purchases Tthis resulted in 23,253 Dth of available gas in excess of the forecast. Actual usage was 313,016 Dths, 67, 516 Dths more than forecast.
02/17/06	~05:00:00	Electric load and weather forecast is updated for Friday – Sunday and given to electric trading	Meteorologist	The Saturday morning temperature forecast remains consistent with Thursday's forecasted low of 1 degree.

Date	Time	Action/ Activity	Who	Comments/ Analysis
02/17/06	~06:00:00	Revised the forecast for LDC natural gas requirements based on weather forecast changes	Manager Gas Supply (PSCO)	The LDC load forecast was revised to 1,181,670 Dth based on Accuweather's forecasted average temperature of 4 degrees. This load forecast resulted in unutilized storage deliverability of 74,337 Dth for gas day Feb. 17, plus authorized overrun is available. Accordingly, no changes were made to the supply plan.
02/17/06	~07:00:00	Received Electric forecasted natural gas requirements for Gas Days February 18th – 21st. In accordance with normal practice, no revised natural gas requirements were provided for electric generation for gas day February 17.	Sr. Gas Buyer – PSCO Electric	The forecasted generation natural gas requirements for Gas Day Feb 18th were 265,000 Dth. The Company planned to meet this requirement with: *183,000 Dth under monthly baseload contracts *10,000 Dth from Young storage. *83,739 Dth of spot gas purchases This resulted in 11,739 Dth of available gas in excess of the forecast. No additional gas was purchased for electric generation for Gas Day Feb 17th.
02/17/06	12:38:00	Rocky Mountain Energy Center (RMEC), a 640 MW combined-cycle under long-term contract, is forced offline by inlet filters plugging, due to very cold temperatures	Real-time dispatch is notified by RMEC operation personnel	Blue Spruce Unit 2, a 150 MW gas turbine, is dispatched and the unit hits the line at 12:55. Blue Spruce Unit 1, a 150 MW gas turbine, came online earlier at 11:40. Both units are dispatched on natural gas. The Denver metro temperature at this time was 3 degrees.
02/17/06	~12:45:00 to ~15:41:00	Phone calls between Gas Control and Gas Supply regarding PSCo generation over burning their gas nominations.	Manager Gas Control, Manager Gas Supply (PSCO), Sr. Transportation Analyst (Gas Control)	Gas Supply buys 31,543 of intra-day gas and storage nomination is set to maximum at Young. The Manchief plant is started to utilize excess storage deliverability from the Young Storage facility. Discussions regarding switching to oil and the cost of penalty gas.

Date	Time	Action/ Activity	Who	Comments/ Analysis
02/17/06	13:33:00	PSCo unit commit for 2/18/2006 is given to the real-time dispatch group	Day-ahead system analyst	The unit commit reflects that RMEC is expected to return no earlier than HE 13 on Saturday – no official estimated return to service date had been provided.
02/17/06	~14:30:00 to ~16:00:00	Gas Control notifies real-time dispatch and Gas Supply that at the current rate of electric gas burn, it is likely that System would over run the nominated gas volume by 93,000 authorized Dth plus about 69,000 Dth unauthorized Several conversations regarding the need to burn less gas take place	Director of Power Operations, Manager Gas Supply (PSCO), Director Gas Supply, Real – time Trader	Discussed the over burn situation as compared to the limited amount of intra-day gas that Gas Supply was able to purchase, starting Manchief to utilize Young Storage, burning fuel oil, increasing amount of economic purchases, and the economics of penalty gas.
02/17/06	15:18:00	Blue Spruce #1 and # 2 trip due to a malfunction of gas valves, which the plant reported [after the fact] was triggered by a "normal" drop in gas pressure	Real-time dispatch is notified by Blue Spruce operation personnel	Cabin Creek unit A; a pumped-hydro facility with a capacity of 160 MW, is dispatched to respond to the loss of 300 MWs of Blue Spruce generation.
02/17/06	~16:00:00	Gas Supply requests real-time dispatch to (1) use fuel oil at Blue Spruce station, (2) evaluate whether Cherokee 4, a 350 MW coal-fired unit, can delay its planned outage, and (3) dispatch Manchief units 11 and 12, 150 MW gas turbines, in order to pull gas from Young storage.	Real-time dispatch	(1) Real-time dispatch requests a restart for both Blue Spruce units on fuel oil. Real-time dispatch plans are to burn oil at Blue Spruce until the units can be brought off-line based on economic power purchases. (2) Cherokee 4 Shift Supervisor is contacted to investigate whether they can delay the outage—they agree to delay the outage (3) Manchief 11 is on-line at 15:07 and Manchief 12 is on-line at 17:35
02/17/2006	~16:00:00	Real-time dispatch purchases 200 MW from SPS to PSCo, using the Lamar Tieline	Real-time dispatch	The Lamar Tie was scheduled for 200 MWs/hr of purchases from SPS HE 17 – 23 and at approximately 19:25, the schedule was extended for HE 24 – HE 9 on Saturday February 18th.
02/17/06	16:11:00	Real-time dispatch sends e-mail to Gas Control to inquire about over-burn penalties which should be factored into our avoided cost signals to the power traders	Director of Power Operations	Real-time dispatch wanted to verify what the penalty was in order to factor that cost into the avoided cost signals. Gas still considered readily available, just more expensive.

Date	Time	Action/ Activity	Who	Comments/ Analysis
02/17/06	16:28:00	Gas Control contacts real-time dispatch via e-mail to confirm that the "per Dth penalty is $0.64"	Manager Gas Control	Real-Time dispatch interprets from this communication that physical gas is readily available, Real-time dispatch continues to operate on the assumption that there is plenty of natural gas, treating the over-burn as an economic issue only. The avoided cost signal to the power traders is increased to factor in the penalty of $0.64 / Dth. This price signal increase does not cause a significant increase in power purchases
2/17/06	17:32:00	Blue Spruce unit 1 hits the line, approximately 1.5 hours after it was called on.	Real-time dispatch	Unit 1 remains on-line until approximately 21:30 when it is released due to falling evening loads. The unit was the most expensive facility on-line during the evening peak load, and was the facility first targeted to come offline once system conditions would permit.
2/17/06	17:35:00	Manchief unit 12 comes on-line, utilizing gas from Young storage as recommended by Gas Supply	Real-time dispatch	Manchief was dispatched for economics at this time, but it also complimented the Gas Supply recommendation to pull natural gas from this specific station due the ability to deliver gas from the Young gas storage facility.
2/17/2006	18:32:00	Blue Spruce Unit 2 attempts to come on-line on fuel oil, as requested following the station trip @ ~15:15	Blue Spruce operations	The unit failed to remain on-line and was forced offline at ~18:48. Blue Spruce tried to start Unit #2 several times on the morning of 2/18 but it could not remain on-line until about 13:00 on Saturday.
2/17/06	~19:56	Manchief unit 12 trips off-line, after the operations staff had repeatedly attempted to bring the unit into emissions compliance.	Manchief plant operations informs real-time dispatch	At approximately 20:00, Manchief staff reported that they didn't feel that they would be able to start the unit and bring it into emissions compliance due to the ambient temperature continuing to drop. The plant reported an ambient temperature of –4 degrees. They declared the unit "unavailable" until the ambient temperature increased to +5 degrees.

Date	Time	Action/ Activity	Who	Comments/ Analysis
2/17/06	~23:54:00	Fort Saint Vrain (FSV), a 732 MW combined-cycle gas plant loses the steam boiler. This results in a loss of ~295 MWs that were being produced with no incremental use of natural gas. The three combustion turbines remain on-line, producing ~437 MWs Plains End is started up at ~00:04 to respond to the loss of FSV's steamer, and runs until ~00:25.	Real-time dispatch	Gas Control is contacted to inquire if we can bring Plains End, a 113 MW facility, composed of 20 reciprocating engines, back on-line Gas Control informs real-time dispatch that it is OK to turn the unit back on for a little while. Dictation below from call @ 23:58 – GC=Gas Control RTD=Real-time dispatch GC: Gas Control this is Mike RTD: Mike this is Robyn GC: Yeah RTD: I lost the steam turbine on FSV, and I need if possible to bring Plains End back on GC: OK RTD: Alright GC: Why did they lose that over there? RTD: I don't know, stuff was freezing up and they were in a frenzy so I didn't stop to talk to them GC: OK RTD: I will call them after things settle down a little –OK? GC: OK for a little while anyway RTD: OK, thanks

Date	Time	Action/ Activity	Who	Comments/ Analysis
2/18/06	~00:35:00	Valmont 5, a 160 MW coal-fired facility trips off-line due to frozen controls. The sudden trip ruptured tubes and the facility is unavailable to return to service until further notice. Real time calls Gas Control to inquire if they can restart Plains End after just shutting it down at approximately 00:25 Plains End comes on-line at ~00:49 and runs until ~01:20.	Real-time dispatch	Gas Control informs real-time that it is OK for a little while. Dictation below from call @ 00:44 – GC=Gas Control RTD=Real-time dispatch GC: Gas Control this is Mike RTD: Mike this is Robyn GC: Yeah RTD: I lost Valmont 5 GC: OK RTD: So, can I turn Plains End on again for a while? GC: For a little while I guess RTD: OK, thank you
2/18/06	04:10:00	FSV trips CT #4, a 150 MW combustion turbine @ ~04:07, while attempting to reduce load to blend in the steamer. Cherokee 4 trips off-line due to electrical problems in the control room @ ~04:10 Real-time dispatch calls Lookout to request a RMRG activation. At ~04:15 Plains End comes on-line to respond to the loss of Cherokee 4. At 04:24 Cabin Creek A starts spilling water due to a loss of reserves.	Real-time dispatch	Real-time dispatch calls Gas Control to inform them that they will be starting the two Ft Lupton combustion turbines, 45 MWs each, to re-establish required spinning reserves. We did not communicate the start up of Plains End to Gas Control. Gas Control states that the turbines must be operated at minimum output levels, as Gas Control is seeing very low gas pressures. Dictation below from call @ 04:22 – GC=Gas Control RTD=Real-time dispatch GC: Gas Control, this is Brian RTD: Brian this is Robyn, um I am getting ready to start-up the Ft Luptons and I am going to leave them at the bottom, but I need some reserves really bad GC: It better be at very bottom because I have absolutely no pressure RTD: OK, alright GC: If they go off, it is not my fault – there is no gas on the system, everything is, we are using more than we're getting in RTD: OK GC: Alright

Date	Time	Action/ Activity	Who	Comments/ Analysis
2/18/2006	04:51	Real-time dispatch requests a start-up on one unit at Blue Spruce	Real-time dispatch to Blue Spruce plant operations	At 04:50 real-time dispatch asks Blue Spruce to start a unit on oil – unit 1 is on-line at approximately 05:20
2/18/06	05:14:00	Gas Control calls real-time dispatch to inform them that they need Plains End to come offline immediately. Reliability order.	Gas Control to real-time dispatch	Real-time dispatch calls Plains End to take the unit off immediately
2/18/06	05:16:00	Gas Control Calls real-time dispatch to confirm that Plains End is coming off-line.	Manager of Gas Control to Real-time dispatch	Gas Control informs real-time dispatch that running Plains End is not a "dollar choice" anymore.
2/18/06	05:18:00	Thermo Carbonic and Thermo Industries (TCTI), a 278 MW combined cycle calls real-time dispatch to inform them that they had lost flow of gas from PSCo.	TCTI plant operations staff to real-time dispatch	Real-time dispatch calls Gas Control to inquire about the lost flow to TCTI. Gas Control informs real-time dispatch that pressure is dropping fast, and that TCTI would need to pull from somebody else. At 05:20 real-time dispatch again asks the second Blue Spruce unit to start on fuel oil The unit fails to come on-line until ~13:00 on Saturday after subsequent failed attempts at approximately 05:50 and 09:45.
2/18/06	05:28:00	TCTI calls to inform real-time dispatch that they lost a jet, are down to 4x2 operation, and restricted to current output , which reduced the plant output by approximately 200 MW. Another unit trip at 06:35 resulted in a further reduction of ~33 MWs of capability	TCTI plant operations calls real-time dispatch	Real-time dispatch assessed the situation and determined Gas Control should be contacted prior to starting any gas-fired units.
2/18/06	05:35:00	Real-time dispatch calls Gas Control to inquire which PSCo operated generation facilities can be supported by the gas system	Real-time dispatch to Gas Control	Gas Control informs real-time dispatch that they can support Zuni 1 and 2 (station capacity of 97 MW) and Arapahoe 5,6,7 (station capacity of 132 MW) on gas. Valmont 7&8 (station capacity of 88 MW), Brighton 1&2 (station capacity of 152 MW), Brush 4 (station capacity of 140 MW) and Plains End (station capacity of 113 MW) can't be supported until further notice. Gas Control states that they will not be able to support Ft Lupton much longer.

Date	Time	Action/ Activity	Who	Comments/ Analysis
2/18/06	~05:40	Real-time dispatch calls to start-up Zuni and Arapahoe 5,6,7 and requests a fuel switch for Ft Lupton CTs	Real-time dispatch	Zuni is notified that they need to bring both units on-line. The station did not know when they would hit the line. Arapahoe is also notified that they need to come on-line as soon as possible.
02/18/2006	05:47	Gas Control contacts Real-time dispatch to discuss switching Ft Lupton units to fuel oil,	Gas Control to Real-time dispatch	Real-time dispatch confirms that we had already asked the plant to switch the Ft Lupton units over to fuel oil.
2/18/06	06:14	Real-time dispatch calls Gas Control to ask about gas availability for Valmont 6. Real-time dispatch further tells Gas Control that, absent additional resources, the electric system will be deficit and a system emergency declaration may be necessary	Real-time dispatch calls Gas Control	Gas Control informs real-time dispatch that electric cannot use additional gas off of the system today. Gas Control states that power will have to be purchased from the market. For HE 8 the real-time dispatcher provided a purchase signal to electric trader to buy 600 MW at any price. Valmont 6 (53 MW) is unavailable due to gas pressure limitations The purchase cost signal remained "buy at any price" through HE 17 on Saturday. Gas Control states that they are going to an Operational Flow Order (OFO) as of that time, that "there is no gas to be had... we can put them out of gas or electric".
02/18/06	06:15:00	Real-time dispatch calls Lookout Control Center	Real-time calls Lookout Control Area Operator	Lookout and real-time dispatch discuss options including purchasing energy, curtailment of the, Interruptible Service Option Credit (ISOC) customers including CFI interruption, diesel generation options
02/18/06	06:55:00	Gas Supply calls real-time dispatch to ensure that all facilities capable of burning fuel oil are dispatched on that fuel.	Gas Supply calls real-time dispatch	Gas Supply informs real-time dispatch that Gas Control is experiencing low pressure alarms. Gas Supply asks whether Ft Lupton CTs, Denver Steam and Zuni can switch to fuel oil
2/18/06	06:59:00	Real-time dispatch calls Zuni to have them switch to fuel oil	Real-time dispatch to Zuni control room operator	The plant is uncertain whether they will be able to start or burn fuel oil. Zuni is not able to come on-line until Saturday afternoon.
2/18/06	07:01	The Control Area operator at Lookout Center contacts real-time dispatch	Lookout Control Area operator and real-time dispatch	Lookout and real-time dispatch discuss the need for power purchases at any price. The electric system purchase signal continues to be "purchase at any cost".
2/18/06	07:11:00	RMEC calls real-time dispatch to determine whether the gas system could support a start-up.	RMEC plant operations to real-time dispatch	Real-time dispatch calls Gas Control to inquire if they could support RMEC pulling gas. Gas Control informs real-time dispatch that they cannot support RMEC start up.

Date	Time	Action/ Activity	Who	Comments/ Analysis
2/18/2006	07:30:00	Real-time dispatch calls Gas Control to inquire if Limon (76 MW) can be started on gas	Real-time dispatch to Gas Control	Gas Control informs real-time dispatch that Limon cannot be supported. Limon unit is unavailable due to gas pressure limitations.
2/18/06	07:39:00	The California ISO calls to offer PSCo emergency energy in response to the Rocky Mountain Security Coordinator	California ISO calls real-time trading	The Cal ISO is one of many counterparties who called to offer assistance to real-time trading. The real-time trader is able to increase purchases into the system from 428 MW in HE 7 to 757 MW in HE 8. In HE 9 a total of 931 MW was scheduled into the system; HE 10 = 1048 MW, HE 11 = 1109 MW and HE 12 = 986 MW.
2/18/2006	07:40:00	Real-time trading enters a second tag for a purchase from Salt River Project (SRP) due to incorrect ATC posting.	Real-time trading	Tri-State transmission had an incorrect ATC posting for HE 9 from SJ345 to Craig. The real-time trader had purchased 58 MW of Tri-State transmission in order to schedule additional power into the system. Tri-State notified PSCo that they could only sell 31 MW of transmission on that path. The real-time trader enters a revised tag for 31 MW from SRP at 07:40, and books out the purchase of 27 MW.
2/18/06	~08:40:00	Front Range Power Company (FRPC), which consists of two GE turbine generators and 1 steam turbine generator with a combined capacity of 480 MWs of which 204 MW is under long term contract to PSCo, lost both units due to frozen water valves.	Two separate Rocky Mountain Reserve Group (RMRG) reserve activations were posted	In this situation, PSCo is required to produce additional energy to cover the shortfall created by the loss of the FRPC combustion turbines. PSCo's share of the response was 217 MW for the first contingency and 204 MWs for the second contingency Real-time dispatch called Lookout Control Center to inform them that, due to low gas pressures, our units could not respond to the RMRG call for reserve activation.
02/18/2006	08:40:00	Real-time dispatch calls Gas Control to inquire if Fruita (19 MW) and Alamosa (36 MWs) can be started.	Real-time dispatch to Gas Control	Gas Control informs real-time dispatch that it would be OK to start the units on gas, but then they need to switch to oil. We had been carrying operating reserves on these units, so we had not asked for them to be started earlier.

Date	Time	Action/ Activity	Who	Comments/ Analysis
2/18/06	~08:40:00	Real-time dispatch initiates a remote start-up on Fruita and Alamosa 1 and 2	Real-time dispatch via Energy Management System (EMS)	The units failed to start. Real-time dispatch contacted the plant contact and requested assistance to get Alamosa on-line. Real-time dispatch contacted Cameo to inquire if they could dispatch an operator to Fruita to get the unit online
2/18/06	~08:40:00	Lookout Center initiates a firm load curtailment of approximately 400 MW in order to meet the RMRG activation	Lookout Control Area operator	Due to generation equipment failure and gas pressure limitations on other facilities, XCEL's available capacity was reduced by ~3200 MW. Absent the gas pressure limitations, the load could have been served with more than 850 MWs of available generation – TCTI = 233, Brighton = 152, Plains End = 113, Valmont 6-8 = 141, Brush 4 = 140 MW, and Limon = 76 MW (Blue Spruce 2 could also be considered available on gas because the unavailability was caused by a freeze on the fuel oil system – if gas could have been supplied the unit would be good for150 MW).

EXHIBIT NO. 11

Exhibit No. 11

CIG and PSCo Pressures February 16 through 18

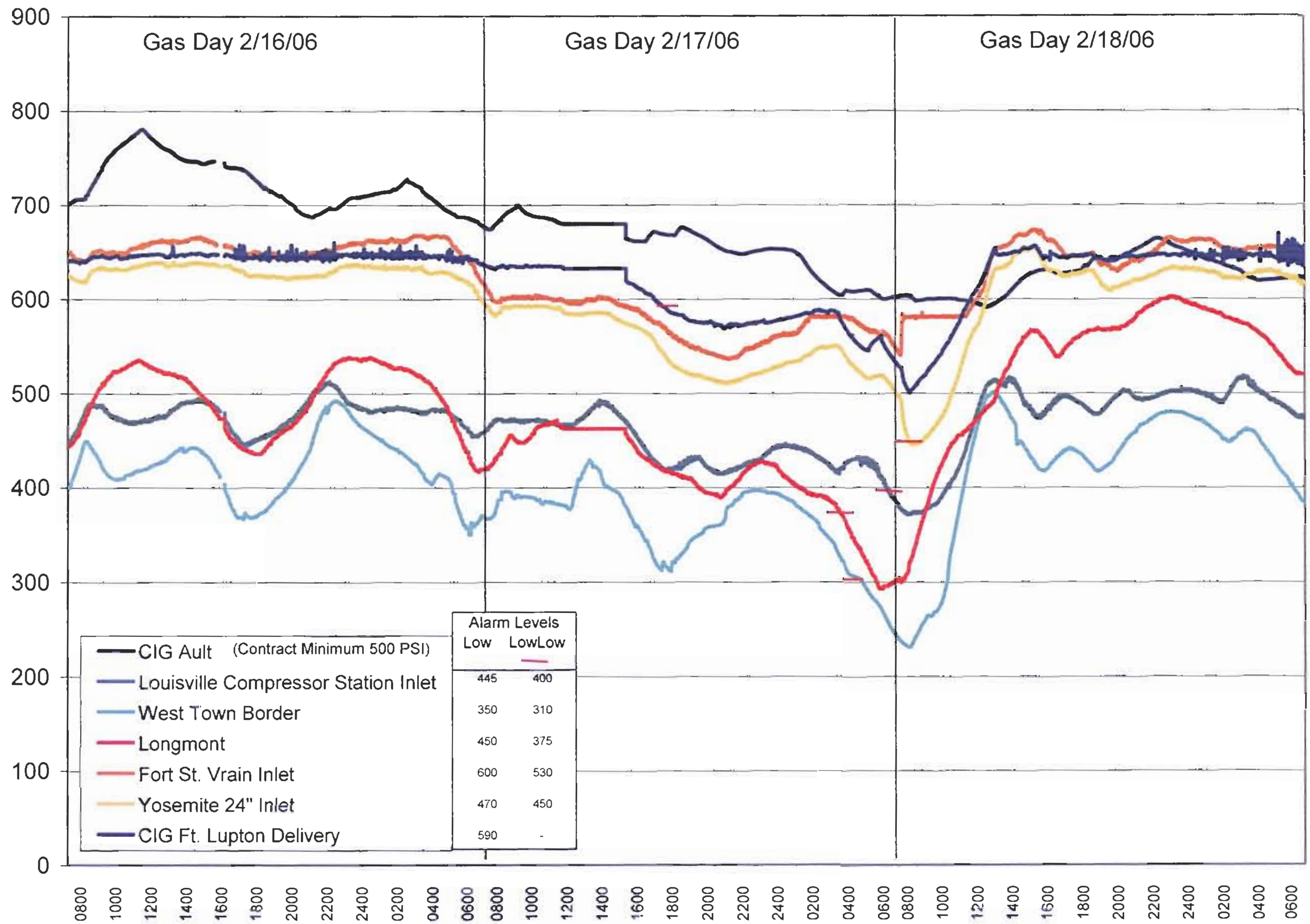
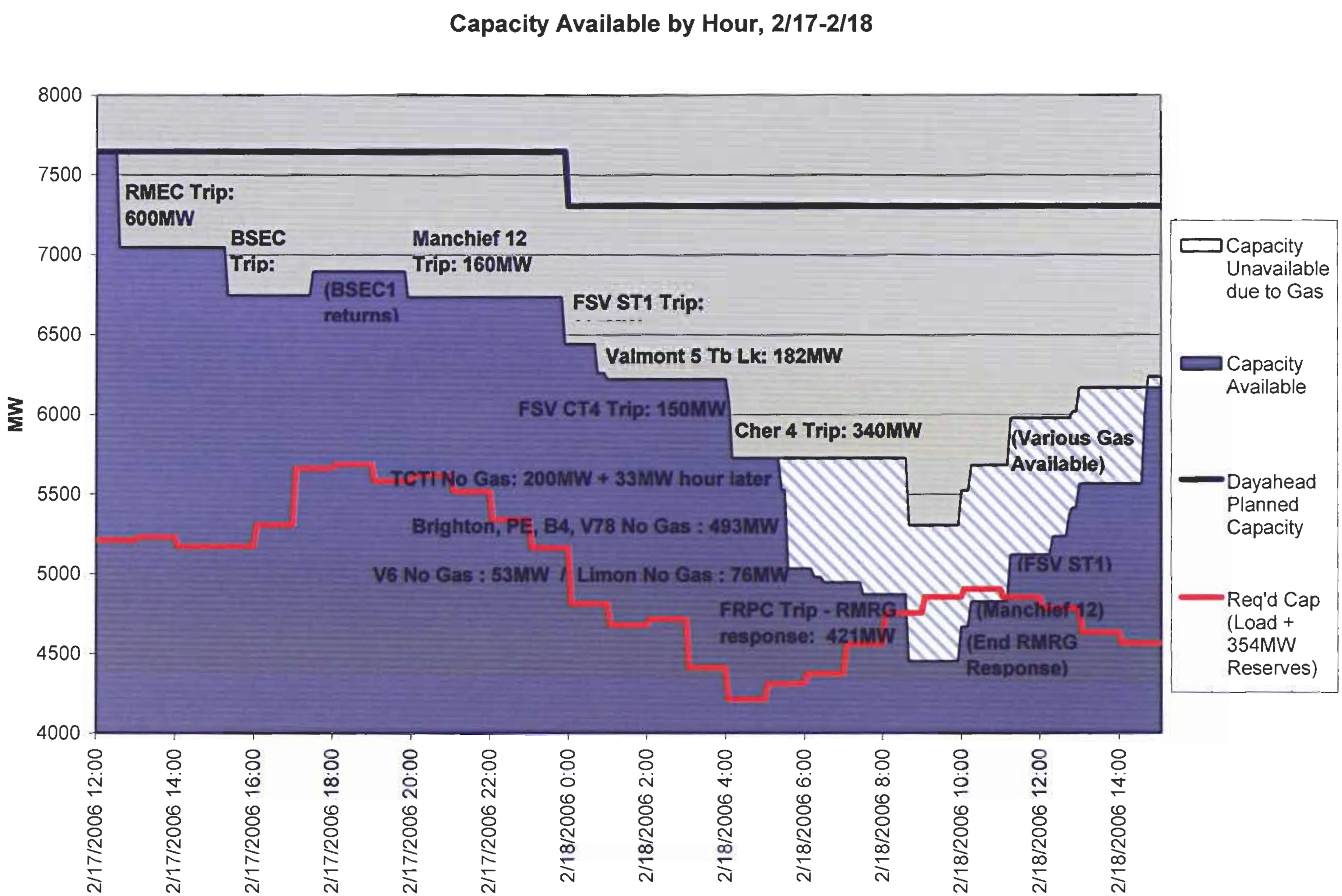


EXHIBIT NO. 12



Capacity Available by Hour, 2/17-2/18
MW
8000
7500
7000
6500
6000
5500
5000
4500
4000
RMEC Trip: 600MW
BSEC Trip:
(BSEC1 returns)
Manchief 12 Trip: 160MW
FSV ST1 Trip:
Valmont 5 Tb Lk: 182MW
FSV CT4 Trip: 150MW
Cher 4 Trip: 340MW
TCTI No Gas: 200MW + 33MW hour later
Brighton, PE, B4, V78 No Gas : 493MW
V6 No Gas : 53MW / Limon No Gas : 76MW
FRPC Trip - RMRG response: 421MW
(Various Gas Available)
(FSV ST1)
(Manchief 12)
(End RMRG Response)
2/17/2006 12:00
2/17/2006 14:00
2/17/2006 16:00
2/17/2006 18:00
2/17/2006 20:00
2/17/2006 22:00
2/18/2006 0:00
2/18/2006 2:00
2/18/2006 4:00
2/18/2006 6:00
2/18/2006 8:00
2/18/2006 10:00
2/18/2006 12:00
2/18/2006 14:00
Capacity Unavailable due to Gas
Capacity Available
Dayahead Planned Capacity
Req'd Cap (Load + 354MW Reserves)

EXHIBIT NO. 7

Substation	Feeder	Time Opened	Time Closed	# of Customers Affected *	Outage Duration (minutes)
Load Group 1					
ALLI	1143	2/18/06 8:47	2/18/06 9:19	303	32
CLAR	1190	2/18/06 8:47	2/18/06 9:19	111	32
NORT	2293	2/18/06 8:47	2/18/06 9:19	1,929	32
SIMM	1020	2/18/06 8:47	2/18/06 9:19	543	32
LEGG	1324	2/18/06 8:48	2/18/06 9:19	802	31
ARGO	1546	2/18/06 8:48	2/18/06 9:20	2,847	32
HAVA	**1937**	**2/18/06 8:48**	**2/18/06 12:48**	**363**	**240**
MARC	1220	2/18/06 8:48	2/18/06 9:20	1,466	32
SULL	1807	2/18/06 8:48	2/18/06 9:20	3,489	32
RALS	2741	2/18/06 8:48	2/18/06 9:20	1,578	32
TOWE	1240	2/18/06 8:48	2/18/06 9:21	62	33
RUSS	1674	2/18/06 8:48	2/18/06 9:22	4,792	34
SEMP	1954	2/18/06 8:48	2/18/06 9:22	2,246	34
SIMM	1029	2/18/06 8:48	2/18/06 9:22	143	34
LEET	2497	2/18/06 8:48	2/18/06 9:22	1,503	34
BANC	1811	2/18/06 8:49	2/18/06 9:22	3,808	33
MEAD	2058	2/18/06 8:49	2/18/06 9:21	2,491	32
CLAR	2069	2/18/06 8:49	2/18/06 9:21	417	32
NORT	2324	2/18/06 8:49	2/18/06 9:21	145	32
JEWE	1033	2/18/06 8:49	2/18/06 9:23	2,432	34
LOUI	1498	2/18/06 8:49	2/18/06 9:23	1,643	34
QUAK	1905	2/18/06 8:49	2/18/06 9:23	2,923	34
BERG	2524	2/18/06 8:49	2/18/06 9:23	4,352	34
SANT	1150	2/18/06 8:50	2/18/06 9:24	2,409	34
RUSS	1671	2/18/06 8:50	2/18/06 9:24	2,303	34
TOLL	1768	2/18/06 8:50	2/18/06 9:24	4,523	34
GREE	**1436**	**2/18/06 8:50**	**2/18/06 12:11**	**2,687**	**201**
ARVA	1707	2/18/06 8:50	2/18/06 9:24	1,662	34
BTER	1358	2/18/06 8:50	2/18/06 9:24	1,275	34
QUAK	1909	2/18/06 8:50	2/18/06 9:24	1	34
WEST	1291	2/18/06 8:50	2/18/06 9:24	18	34
CLAR	1195	2/18/06 8:50	2/18/06 9:24	76	34
MEAD	2056	2/18/06 8:51	2/18/06 9:24	2,822	33
ARGO	1549	2/18/06 8:51	2/18/06 9:25	1	34
LOUI	1493	2/18/06 8:51	2/18/06 9:25	0	34
RIVE	1646	2/18/06 8:51	2/18/06 9:25	4,185	34
TOLL	1764	2/18/06 8:51	2/18/06 9:25	811	34
JEWE	1032	2/18/06 8:51	2/18/06 9:25	2,149	34
GREE	1442	2/18/06 8:51	2/18/06 9:26	3,256	35
UNIV	1924	2/18/06 8:51	2/18/06 9:26	1,566	35
NCAR	1556	2/18/06 8:52	2/18/06 9:26	3,506	34
ARVA	1704	2/18/06 8:52	2/18/06 9:26	2,538	34
BTER	1344	2/18/06 8:52	2/18/06 9:27	1,954	35
LAKE	1558	2/18/06 8:52	2/18/06 9:27	5,456	35
SAND	1746	2/18/06 8:52	2/18/06 9:26	2,905	34
TECH	1054	2/18/06 8:52	2/18/06 9:27	602	35

Substation	Feeder	Time Opened	Time Closed	# of Customers Affected *	Outage Duration (minutes)
MAPL	1755	2/18/06 8:52	2/18/06 9:27	2,104	35
SRDG	1282	2/18/06 8:52	2/18/06 9:27	207	35
WASH	1263	2/18/06 8:54	2/18/06 9:27	4,065	33
ALLI	1144	2/18/06 8:54	2/18/06 9:27	901	33
LEGG	1326	2/18/06 8:54	2/18/06 9:27	2,521	33
ARGO	1547	2/18/06 8:54	2/18/06 9:29	123	35
IDAH	2944	2/18/06 8:54	2/18/06 9:29	2,438	34
LEET	2493	2/18/06 8:54	2/18/06 9:29	1,696	35
RIDG	2042	2/18/06 8:54	2/18/06 9:29	3,775	35
SRDG	1281	2/18/06 8:55	2/18/06 9:29	1,309	34
CLAR	1192	2/18/06 8:55	2/18/06 9:27	1,857	32
NORT	2323	2/18/06 8:55	2/18/06 9:27	1,114	32
GLEN	1918	2/18/06 8:55	2/18/06 9:31	1,853	36
RUSS	1672	2/18/06 8:55	2/18/06 9:31	5,217	36
SULL	1802	2/18/06 8:55	2/18/06 9:31	4,561	36
LEET	2494	2/18/06 8:55	2/18/06 9:31	3,792	36
ARVA	1701	2/18/06 8:56	2/18/06 9:31	4,763	35
			Total	**129,389**	

Load Group 2					
LEGG	**1322**	**2/18/06 9:19**	**2/18/06 12:41**	**215**	**202**
LITT	**1738**	**2/18/06 9:19**	**2/18/06 10:53**	**1,174**	**94**
SEMP	1951	2/18/06 9:19	2/18/06 9:50	3,899	31
UNIV	1922	2/18/06 9:19	2/18/06 9:49	3,150	30
BANC	**1816**	**2/18/06 9:19**	**2/18/06 13:04**	**4,392**	**225**
BROO	2731	2/18/06 9:20	2/18/06 9:52	59	32
SEMP	1957	2/18/06 9:20	2/18/06 9:52	3,160	32
LEET	2488	2/18/06 9:20	2/18/06 9:52	39	32
KEND	1974	2/18/06 9:21	2/18/06 9:52	3,755	31
SAND	1743	2/18/06 9:21	2/18/06 9:52	395	31
QUAK	1903	2/18/06 9:21	2/18/06 9:52	2,929	31
GREE	1437	2/18/06 9:21	2/18/06 9:52	3,265	31
TOWE	1242	2/18/06 9:21	2/18/06 9:52	808	31
MAPL	1752	2/18/06 9:21	2/18/06 9:52	783	31
BROO	2734	2/18/06 9:21	2/18/06 9:52	3,135	31
BUCK	1270	2/18/06 9:22	2/18/06 9:53	5,083	31
MARC	1225	2/18/06 9:22	2/18/06 9:53	1,059	31
RALS	2744	2/18/06 9:22	2/18/06 9:53	4,261	31
WEST	1293	2/18/06 9:22	2/18/06 9:53	1,593	31
CLAR	1197	2/18/06 9:22	2/18/06 9:53	887	31
KEND	1978	2/18/06 9:23	2/18/06 9:54	2,506	31
LOUI	1495	2/18/06 9:23	2/18/06 9:54	1,416	31
PRAI	1357	2/18/06 9:23	2/18/06 9:54	1,203	31
TECH	2074	2/18/06 9:23	2/18/06 9:54	470	31
EAST	1574	2/18/06 9:23	2/18/06 9:54	6,040	31
NCAR	**1557**	**2/18/06 9:24**	**2/18/06 12:49**	**3,038**	**205**

Substation	Feeder	Time Opened	Time Closed	# of Customers Affected *	Outage Duration (minutes)
QUAK	1906	2/18/06 9:24	2/18/06 9:54	56	30
SOUT	1534	2/18/06 9:24	2/18/06 9:54	2,948	30
GREE	1444	2/18/06 9:24	2/18/06 9:54	1,024	30
ARVA	1706	2/18/06 9:25	2/18/06 9:54	5,608	29
BTER	1347	2/18/06 9:25	2/18/06 9:55	4,623	30
LAKE	1563	2/18/06 9:25	2/18/06 9:55	4,521	30
SULL	1805	2/18/06 9:25	2/18/06 9:55	3,099	30
TECH	1052	2/18/06 9:25	2/18/06 9:55	0	30
ARGO	1545	2/18/06 9:26	2/18/06 9:55	1,001	29
WASH	1267	2/18/06 9:26	2/18/06 9:55	2,423	29
LOUI	1492	2/18/06 9:26	2/18/06 9:55	305	26
PRAI	1354	2/18/06 9:26	2/18/06 9:55	1,363	29
CLAR	1194	2/18/06 9:26	2/18/06 9:55	229	29
ARGO	1548	2/18/06 9:26	2/18/06 9:56	6,708	30
NCAR	1554	2/18/06 9:26	2/18/06 9:56	3,054	30
PRAI	1356	2/18/06 9:26	2/18/06 9:56	1,455	30
SOUT	1532	2/18/06 9:26	2/18/06 9:56	2,480	30
SRDG	1284	2/18/06 9:26	2/18/06 9:56	999	30
GREE	1441	2/18/06 9:27	2/18/06 9:57	1,302	30
TOLL	1766	2/18/06 9:27	2/18/06 9:57	2,090	30
RALS	2747	2/18/06 9:27	2/18/06 9:57	1,277	30
ARVA	1702	2/18/06 9:28	2/18/06 9:57	3,195	29
MEAD	2103	2/18/06 9:28	2/18/06 9:57	3,362	29
BERG	1942	2/18/06 9:30	2/18/06 9:58	2,494	28
LAKE	1557	2/18/06 9:30	2/18/06 9:58	2,719	28
LOUI	1497	2/18/06 9:30	2/18/06 9:58	50	28
SEMP	**1953**	**2/18/06 9:30**	**2/18/06 13:22**	**5,906**	**232**
TOLL	1761	2/18/06 9:30	2/18/06 9:58	5,192	28
			Total	**128,197**	

Load Group 3					
BROO	2733	2/18/06 9:52	2/18/06 10:14	1,108	22
KEND	1977	2/18/06 9:52	2/18/06 10:14	578	22
LEET	2490	2/18/06 9:52	2/18/06 10:14	3,244	22
SEMP	1958	2/18/06 9:52	2/18/06 10:14	3,923	22
SAND	1747	2/18/06 9:52	2/18/06 10:14	142	22
TOWE	1243	2/18/06 9:52	2/18/06 10:14	1,092	22
QUAK	1904	2/18/06 9:52	2/18/06 10:14	2,261	22
GREE	**1438**	**2/18/06 9:52**	**2/18/06 12:18**	**2,135**	**146**
MAPL	1754	2/18/06 9:53	2/18/06 10:14	171	21
RIDG	2043	2/18/06 9:54	2/18/06 10:14	110	20
UNIV	1923	2/18/06 9:54	2/18/06 10:14	2,337	20
BUCK	1271	2/18/06 9:54	2/18/06 10:14	4,001	20
CLAR	2068	2/18/06 9:54	2/18/06 10:14	3,351	20
MEAD	2057	2/18/06 9:54	2/18/06 10:14	3,276	20
GLEN	1916	2/18/06 9:54	2/18/06 10:14	3,487	20

Substation	Feeder	Time Opened	Time Closed	# of Customers Affected *	Outage Duration (minutes)
JEWE	1036	2/18/06 9:54	2/18/06 10:14	5,003	20
RUSS	1673	2/18/06 9:54	2/18/06 10:14	963	20
TECH	2076	2/18/06 9:54	2/18/06 10:14	20	20
LOUI	1496	2/18/06 9:54	2/18/06 10:14	80	20
KEND	1979	2/18/06 9:55	2/18/06 10:14	2,027	19
MART	1681	2/18/06 9:55	2/18/06 10:14	0	20
TECH	2077	2/18/06 9:55	2/18/06 10:14	372	19
BUCK	1273	2/18/06 9:55	2/18/06 10:14	4,303	19
SAND	1748	2/18/06 9:55	2/18/06 10:14	1,247	19
BTER	1357	2/18/06 9:55	2/18/06 14:02	227	247
LITT	1732	2/18/06 9:55	2/18/06 10:15	568	20
SULL	1806	2/18/06 9:55	2/18/06 10:15	3,454	20
TECH	1053	2/18/06 9:55	2/18/06 10:15	942	20
NORT	1425	2/18/06 9:56	2/18/06 10:59	370	63
BSDT	BA451	2/18/06 9:56	2/18/06 10:15	HCEA	19
CRAT	CT961	2/18/06 9:56	2/18/06 10:15	YVEA	19
VAIL	VA411A	2/18/06 9:56	2/18/06 10:15	HCEA	19
ASPE	AP411A	2/18/06 9:56	2/18/06 10:15	HCEA	19
GJCT	1102	2/18/06 9:56	2/18/06 10:15	5,141	19
PARA	2474	2/18/06 9:56	2/18/06 10:15	660	19
ASPE	AP441A	2/18/06 9:56	2/18/06 10:15	HCEA	19
BSDT	BA461	2/18/06 9:56	2/18/06 10:30	HCEA	34
CRAT	CT921	2/18/06 9:56	2/18/06 10:27	YVEA	31
ASPE	AP421C	2/18/06 9:56	2/18/06 10:30	HCEA	34
CRYS	CD431B	2/18/06 9:56	2/18/06 10:30	HCEA	34
PARA	2475	2/18/06 9:56	2/18/06 10:30	HCEA	34
VAIL	VA421A	2/18/06 9:56	2/18/06 10:30	HCEA	34
BCRK	BC421B	2/18/06 9:56	2/18/06 10:30	HCEA	34
ASPE	AP431A	2/18/06 9:57	2/18/06 10:15	HCEA	18
AVON	AV461A	2/18/06 9:57	2/18/06 10:15	HCEA	18
GJCT	1104	2/18/06 9:57	2/18/06 10:16	830	19
VAIL	VA431A	2/18/06 9:57	2/18/06 10:15	HCEA	18
BSDT	BA411	2/18/06 9:57	2/18/06 10:16	HCEA	18
STEA	ST931	2/18/06 9:57	2/18/06 10:15	YVEA	18
BCRK	BC431A	2/18/06 9:57	2/18/06 10:15	HCEA	18
COOL	CM411A	2/18/06 9:58	2/18/06 10:16	HCEA	18
CRYS	CD451B	2/18/06 9:58	2/18/06 10:16	HCEA	18
ASPE	AP451A	2/18/06 9:58	2/18/06 10:16	HCEA	18
BCRK	BC441B	2/18/06 9:58	2/18/06 10:16	HCEA	18
VAIL	VA431B	2/18/06 9:58	2/18/06 10:16	HCEA	18
WOLC	WC411A	2/18/06 9:58	2/18/06 10:16	HCEA	18
UTEG	G941	2/18/06 9:58	2/18/06 10:16	GVEA	18
BCRK	BC461A	2/18/06 9:58	2/18/06 10:15	HCEA	17
ASPE	AP451B	2/18/06 9:58	2/18/06 10:16	HCEA	18
COOL	CM421A	2/18/06 9:58	2/18/06 10:16	HCEA	18
GJCT	1108	2/18/06 9:58	2/18/06 10:16	4,628	18
VAIL	VA411B	2/18/06 9:58	2/18/06 10:16	HCEA	18

Substation	Feeder	Time Opened	Time Closed	# of Customers Affected *	Outage Duration (minutes)
WOLC	WC421A	2/18/06 9:58	2/18/06 10:16	HCEA	18
CRYS	CD421B	2/18/06 9:58	2/18/06 10:16	HCEA	18
ASPE	AP461B	2/18/06 9:58	2/18/06 10:16	HCEA	18
AVON	AV411A	2/18/06 9:58	2/18/06 10:16	HCEA	18
WOLC	WC451A	2/18/06 9:58	2/18/06 10:16	HCEA	18
BSDT	BA471	2/18/06 9:58	2/18/06 10:16	HCEA	18
COOL	CM451A	2/18/06 9:58	2/18/06 10:16	HCEA	18
GJCT	1106	2/18/06 9:58	2/18/06 10:17	3,545	19
VAIL	VA421B	2/18/06 9:58	2/18/06 10:16	HCEA	18
			Total	**65,596**	

* Note: Feeders serving Electric Association customers are denoted as:
HCEA - Holy Cross Electric Association
GVEA - Grand Valley Electric Association
YVEA - Yampa Valley Electric Association