RELIABILITY OF PUBLIC SERVICE COMPANY OF COLORADO'S ELECTRIC DISTRIBUTION SYSTEM

INITIAL REPORT TO THE
COLORADO PUBLIC UTILITIES COMMISSION
by the Staff of the Colorado Public Utilities Commission
and
The Office of Consumer Counsel

January 14, 2004

Table of Contents

Tables, Charts, Figures, and Attachments

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Executive Summary

Public Service Company of Colorado's[1] (PSCo's or the Company's) customers have experienced increasingly frustrating electricity service outages over the past two years. While much of the focus on outages has been concentrated during the summer peak when the seasonal air conditioning load is greatest, customers' frustration is not solely directed at peak-period outages. As shown by the increasing number of complaints to the Commission throughout the year, customers' frustration with the Company's service is increasing. This report responds to these customer concerns.

On August 27, 2003 Public Utilities Commission (PUC or Commission) Director Bruce N. Smith and Office of Consumer Counsel (OCC) Director Ken V. Reif initiated a joint agency inquiry concerning the performance of PSCo's distribution system.

The letter from Directors Smith and Reif initiating the inquiry and seeking the Company's cooperation was directed to Mr. Fred Stoffel, Vice-President of Policy Development, for Xcel Energy, Inc., which is the holding corporation for PSCo.[2] (Attachment 1) The letter committed that an inquiry would be completed and a report would be submitted to the Commission providing recommendations for additional action as necessary. This report to the Commission provides a summary of the joint inquiry and recommends additional actions for the Commission's consideration.

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[1] While customers may know Company as Xcel Energy, Inc., the Company is regulated as Public Service Company of Colorado.
[2] This letter is provided as Attachment 1.

In particular, Staff and the OCC examined the following issues:

I. The high rate of failure of distribution transformers and whether PSCo is taking adequate measures to address the problem;

II. Whether the Company’s systems and engineering practices are adequate to identify inadequacies in its distribution infrastructure, particularly in older neighborhoods;

III. How PSCo communicates with customers during outages and whether customers are receiving current and adequate information;[3]

IV. How PSCo dispatches and communicates with its repair crews;

V. Whether the resources dedicated to the operation and maintenance of the distribution system appear adequate; and,

VI. Whether adequate capital dollars are dedicated by PSCo to maintain its distribution infrastructure and to refurbish this infrastructure.

This report is organized into five sections, which mirror the issues identified in the letter of inquiry. Due to the interrelationship of operation and maintenance expenses and capital expenditures, these two issues are combined into one section in the body of the report. The report concludes with a summary of Staff and OCC’s[4] general recommendations, discusses revising the Company’s Quality of Service Plan (QSP), and identifies alternative procedural options considered by Staff and the OCC.

The inquiry and the report have taken more time than anticipated because the process has been dynamic, not static. As problems have been identified, PSCo procedures have been modified to address the problems.[5] Staff and OCC believe that PSCo has

[3] The issue of data integrity raised by audit activities of Minnesota regulators is discussed as part of this issue.
[4] In gathering and analyzing data, Staff focused on Sections 1 through 4, while OCC focused on Section 5.
[5] As a demonstration of the dynamic nature of this inquiry, in mid-December of 2003 the Company requested a special meeting with the Staff and OCC to acknowledge that based on its own internal management review of the metro Denver/Boulder area the Company had under-reported outage

cooperated with the effort to identify problems[6] and to initiate solutions.

In general, Staff and the OCC believe that outage and customer complaint trends show diminishing reliability of electric service to PSCo's Colorado customers over a period of years. Reversing that trend will likely take time and may not involve easy solutions.

In reviewing our conclusions and recommendations, it should be noted that, while the Company cannot control consumers' demand for electricity, *it can manage how it plans for and responds to that demand.* When PSCo initially designed its electric distribution system, it designed the system sufficiently large to serve customer needs for decades in the future because reinforcing infrastructure can be costly. Design decisions at that time were within the Company's control and remain within the Company's control at this time.

However, when initial systems were designed and installed in many older neighborhoods air conditioners were not common household appliances, TVs and dishwashers were considered luxury items, and computers, microwave ovens, VCRs and DVDs did not exist. Today consumers' needs for electricity *do include* air conditioning, TVs, dishwashers, microwaves, computers and many other appliances and electronic devices. These consumer needs for electricity are not likely to decrease in the future.[7] Additionally, consumer expectations about service generally do not decrease, but rather increase, over time.

While prudent utilities use load research and load forecasting techniques to track and predict overall system changes in consumers' demand, measuring customers' demand for electricity, household-by-household or distribution-area-by-distribution-area, is not an exact science. Customers' demands change over

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times in the first and second quarter 2003 Quality of Service (QSP) reports filed with the Commission.

[6] For example, while Staff identified the system data issues during the course of this inquiry, it had not yet fully estimated the magnitude of the 2003 problem throughout PSCo's system. If the Company's management had not initiated the internal review, more Commission resources would have been necessary to isolate the source of the system data problems, either as part of this effort or as part of its annual review of QSP results.

[7] While demand side management programs may modify or moderate customer demand in peak time periods, it is difficult to predict results of these programs in an area served by a specific distribution transformer.

time and each customer is different. Members of a household may add air conditioning after a home is built; an additional TV or computer may be added as children move through school years, but removed as children go on to college; families move taking their demand for electricity to a new location – all impacting overall demand at a particular geographic location, and consequently impacting demand for electric service distribution-area-by-distribution-area.

Not recognizing that predicting demand household-by-household or distribution-area-by-distribution-area is an inexact science is unrealistic and unwise. Similarly, not recognizing that increasing demand for electricity stresses the existing infrastructure and its maintenance thereof is also unrealistic and unwise. The result of these two colliding realities is that without recognizing that increased consumers' needs for electricity are stressing the system, without recognizing that infrastructure refurbishment and maintenance is critical, and without taking actions to solve both, increased consumer complaints are likely to continue.

The overall conclusions and recommendations of this inquiry follow, with recommendations split between recommendations for Company action and recommendations for Commission action. As the inquiry proceeded, we found that many of the issues were intertwined in cause and effect. As a result, some of our overall recommendations span multiple issues. Conclusions and recommendations for each issue are discussed more comprehensively within the respective section that addresses each issue.

Conclusions:

1) PSCo's existing systems do not readily identify the distribution areas where demand for electricity exceeds the capacity of the designed electric distribution system. While the Company knows, in general, that customer demand for electricity during summer peak periods and throughout the year is increasing, the Company does not currently have a good method to forecast increased customer load by individual distribution transformer serving area.

2) PSCo's efforts during the summers of 2002 and 2003 to respond to the increasingly high rate of failure of neighborhood distribution transformers have been only partially effective.

3) If PSCo does not develop a method to proactively identify when consumer demand in distribution areas is exceeding the infrastructure in place, customer complaints are likely to continue and to increase.

4) The Company’s response to customer concerns in South Denver and parts of Centennial demonstrate that at least in some cases the Company is not adequately identifying and responding to chronic outages in parts of the metro area without intervention by external advocates. It is not clear if the Company’s responses in South Denver and parts of Centennial are isolated events; however, consumer complaint data indicates that chronic outages are not limited to these areas and are increasing at an alarming rate; consequently, intervention is necessary to evaluate not only the extent of, but also the causes of, and solutions to these chronic outages.

5) Customers’ concerns about not receiving adequate, accurate, and current information both during the March and Mother’s Day snowstorms of 2003 and subsequent to these storms are legitimate concerns. During the storms, the Company’s normal prioritization and dispatch activities were not effective because of a number of operational and data problems with the Company’s Outage Management System (OMS). Other OMS-related data problems compounded these inaccuracies. Customers in the Centennial area were particularly impacted by these system failures; however, the system failures impacted the entirety of the metro Denver/Boulder areas. These operational and data problems resulted in an understatement of outages reported to customers and to the Commission. The magnitude and scope of the understatement is not yet fully determined.

6) It is unclear if PSCo’s management performed adequate system stress testing to ensure the OMS was adequately sized to operate during typical Colorado storm conditions. While the Company has recently indicated that it has modified its system to prevent such reoccurrence, neither Staff nor the OCC currently has the technical expertise to assess whether the system is adequately sized to meet current needs.

7) The Company's recently revised practices concerning communications with critical care customers and customers on life support systems need additional review.

8) Staff and the OCC have not identified any specific evidence that the dispatch of repair crews and communications with these crews is contributing to extended or frequent distribution system outages.

9) The company's annual spending on distribution operations and maintenance has generally declined while its annual dividend payments to Xcel have increased. The company's capital investment in new distribution facilities has also generally declined while Xcel has reduced the amount of capital it has made available to the Company. This data by itself does not establish the "correct" level of maintenance and investment for the company, but the trends are troubling and indicate a need for further investigation.

Recommendations to the Company:

1) While improvements in the policy to timely replace failed transformers and other equipment can mitigate customer impact once transformers and other equipment fail, this policy should be used in addition to and not as a substitute for proactive identification and replacement of problem transformers and other equipment. The Company should enhance its load forecasting and management and preventive maintenance practices to include identifying and reinforcing the distribution areas where demand for electricity exceeds the capacity of the designed system and where frequent, chronic, or recurring equipment outages occur.

2) The efforts of PSCo's Distribution Transformer Team to timely replace transformers upon failure should be continued and enhanced. The program's enhancements should include, but should not be limited to, enhancements to timely replace other distribution equipment with recurring or chronic outage patterns in addition to timely transformer replacements.

3) While PSCo's efforts to develop a proactive transformer replacement model[8] were only marginally effective during the

[8] While the Company's efforts to date have focused on a predictive model for distribution transformers, conceptually the dual concepts of targeted proactive replacement for problem equipment and preventive maintenance equipment apply to equipment other than transformers as well.

summer of 2003, it should continue to develop such a model[9] because the electric load is likely to continue to increase and the infrastructure will continue to age. Consequently, until effective proactive predictive models are implemented, it may be necessary for PSCo to consider returning to its former practice of assigning a larger number of distribution engineers than are currently employed to monitor and effectively maintain the distribution system.

4) The Company should make available its modified practices concerning communications with critical care customers and customers on life support for the Commission's, Staff's and the OCC's review. If necessary, Staff and OCC should supplement this report on the issue and make additional recommendations after that review.

Recommendations to the Commission:

1) The Commission should require a focused performance assessment, at the Company's expense, by an independent third-party engineering and management firm to evaluate the current state of repair of the Company's distribution system and its capability to serve current and foreseeable load. As parts of this assessment, the firm should evaluate whether the Company's:

   - Distribution system in its current condition meets industry standards and whether it is capable of serving current and foreseeable load;

   - Preventive maintenance practices comport with best industry practices and should recommend areas for improvement if deficiencies are identified;

   - Resources are sufficient to identify and fix the causes of frequent, chronic, and recurring outage problems and recommend areas for improvement if deficiencies are identified;

   - OMS and related systems are adequately sized and sufficiently robust to ensure accurate and timely

[9] The Company may need to evaluate other information (such as outage frequency by component) to develop an effective program rather than focusing solely on its current asset optimization model.

prioritization, tracking, and reporting of customer outages;[10]

- Internal management controls are sufficient to ensure that outage information is timely recorded, accurate, complete, and reliable.

2) The Commission should require PSCo to publicly present its action plan to resolve all of the issues in this inquiry to the Commission at a special open meeting during February of 2004 and should provide monthly written progress updates on implementation of its plan beginning in April of 2004. We believe that this information in conjunction with the information from (3) below will allow the Commission to evaluate the effectiveness of the Company's progress.

3) The Commission should authorize a review of whether the existing Quality of Service Plan (QSP) structure and incentives are sufficient to induce the Company to adequately and effectively respond to customer issues. In the interim, while the QSP is under review, the Commission should order the Company to file a monthly status report. Using this report, the Commission can monitor and gauge the Company's progress and performance toward improving its service to customers. We recommend that the Company work with Staff and OCC to determine what information[11] should be included in these monthly progress reports.

[10] This "stress test" should be given top priority and modifications immediately implemented if deficiencies are identified.
[11] For example, the following information should be considered by the Company, Staff, and OCC: QSP information; Customer Average Interruption Frequency Index (CAIFI); 10 worst distribution feeders including planned and accomplished repairs; quantification and identification of customers receiving frequent or extended outages.

I. The High Rate of Failure of Distribution Transformers and Whether PSCo Is Taking Adequate Measures to Address the Problem

A. Introduction and History

A distribution[12] transformer is the device that transforms the voltage level from a primary distribution voltage level (usually 25 or 13 kilovolts[13] (kv)) to a voltage level that can be used by a household. Household appliances typically use power at 120 volts. Stoves and air conditions typically use power at 240 volts. Electric utilities build the primary distribution at this higher voltage level because it is more efficient to transmit power at higher voltages. Consequently, it is necessary to have a device that changes the power from the primary voltage level to the level that can be used by consumers.

Transformers typically weigh upwards of 600 pounds and serve from four to twelve customers. They can be mounted on a pole or can be placed on the ground served by underground cables. When a distribution transformer fails, all customers served by that transformer will be without power. Distribution transformers can be purchased in various sizes. In general, as the size increases, both the cost and the weight of the transformer also increase.

Distribution transformers, as part of a system, are not designed in isolation. Transformers are designed along with other equipment in the distribution system (fuses, re-closers[14] and sectionalizers,[15] etc.) to “pop” or “blow” or “open” in the event of a short-circuit on the system or in the event of a system overload condition. In such conditions, electric flow to the home is stopped (often termed an “open” or an “open circuit”) to prevent electrical fires, to protect customers and their property, and to protect the equipment on the system from permanent damage. The goal of the system when an outage occurs

[12] See Figure 1 for pictorial of the parts of an electric system.
[13] A kilovolt is 1000 volts.
[14] A re-closer is a device that “re-closes” after a circuit initially fails in hopes that the problem that caused the circuit failure was but a brief and momentary problem.
[15] A sectionalizer is a mechanical device that is used to “segment” or “isolate” the cause of an electrical problem, with the goal to restore service to as many customers as quickly as possible.

is to isolate the outages to the smallest number of affected customers as quickly as possible.

A distribution transformer may fail for a variety of reasons including: weather events such as lightning or ice on tree branches that cause interference with aerial wires; animals; aging plant that is not maintained and/or wearing out; other malfunctioning that causes fuses associated with a transformer to blow; or transformer overload conditions.

When a transformer fails, the Company must decide whether the transformer or its associated protection equipment failed because the transformer was too small to meet the customer's load or whether the outage is caused by another reason. In many cases the transformer fuse can simply be reset. The time to simply reset the transformer can be from twenty minutes to multiple hours if the technician determines that "resetting" the transformer will solve the problem. The location of the transformer, travel time to reach the site, weather conditions and workload often impact the timeliness of the reset.

However, if the technician determines that the transformer needs to be replaced, it takes considerably more time. Once a technician identifies that a transformer needs to be changed, it typically requires from 4-12 hours to actually physically change the transformer. As stated previously, it is not unusual for a transformer to weigh over 600 pounds. Consequently, replacing a transformer is not a simple task. The transformer may be either mounted on a pole or located on the ground. If it is mounted on a pole, changing a transformer requires using a truck with a bucket to reach the transformer or using special rigging in conjunction with a multi-member line crew. If the transformer is located on the ground, obtaining access to the transformer may be a challenge due to landscaping.

Alternatively, a transformer failure may occur because the electric load is too large. Residential and commercial business customers' demand for electricity has increased over time. Consequently, components of PSCo's distribution system, including distribution transformers, may require bolstering. If the transformer failure is due to overload conditions, this "too large" load often occurs in the mid-summer when the summertime peak air conditioning load is added to other less seasonal demands for electricity.[16] However, unlike when a fuse blows in

[16] PSCo's past load forecasting efforts in Colorado have shown it is important to consider the number of homes that now have air conditioning (both retrofitted as well as new installations) because

a home, the solution is not always as simple as resetting the fuse, shutting off some of the appliances, or moving an appliance to another outlet.

In the past distribution engineers monitored PSCo's distribution system.[17] Engineers were assigned a portion of the system for which they were responsible. Distribution system capabilities and components, including the proper size of transformers, were matched to loads on portions of the system. Overloaded transformers and other components were located and replaced by these engineers.

Over time the Company largely supplanted the efforts of these engineers with a program of simply replacing distribution system components, especially transformers, as they failed. Many transformers were provided with new fuses and not replaced. After multiple failures, transformers were scheduled for replacement along with other work activities. These replacements were not given priority over other assignments. This procedure has resulted in frequent and extended outages for customers served by these failed transformers.

Unfortunately, while a distribution transformer failure has a significant and direct negative impact on the customers served by the failure, the outage may be overlooked by system managers because the system outage minutes[18] caused by one distribution transformer failure may be relatively small compared to total system outage minutes because each distribution transformer only serves a small number of customers.[19] Similarly, overload outages caused by any device failure can be overlooked because these outages only generally occur at peak times and may not recur until the next peak period if the fuse is reset after the peak conditions dissipate.

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air conditioning causes a substantial increase in the peak summertime electric load.

[17] The distribution system begins where the voltage drops within the substation and ends at the connection to the customer's premises. Thus it includes cable, fuses and systems to protect the system, distribution transformers to drop the voltage even further, drop cables to the customer's premises, and meters. (See Figure 1)

[18] System outage minutes are measured as System Average Interruption Duration Index (SAIDI), which is a summation of the average outage minutes per customer for a year for all outages greater than one minute.

[19] For example, the Regional SAIDI for the Denver Metro area for the period ended December 2002 was calculated based on 212,086 customers. One customer would need to be without service for 212,086 minutes (or about 147 days) in order to cause the Denver Metro area index to increase by one minute per customer.

The Company has presented information that suggests that its distribution transformer failures represent only one-half of 1 percent[20] of total outages. However, presenting that logic to customers impacted by repeated peak period outages within a short period of time may imply that the problem is not important, and ignores a very real and growing problem for Colorado customers. While the problem may be focused on localized areas, the problem is huge to the customers who are impacted in those local areas.

Within Colorado, overload outages have been increasing over time. Table D1-4 from the *Report on Staff Investigation of Public Service Company of Colorado Power Outages, October 13, 1998* (Attachment 2), shows that "overloads" on PSCo's system increased during the years from 1993 through 1998.[21]

Recently, from the years 2001 through 2003, increasing numbers of distribution transformer failures due to overloads during summer months have caused an increasing number of outages. For the Denver area during July of the years from 2001 to 2003 there were: increases in complaints about transformers to the PUC; increases in the percentage of repair complaints to the PUC that were related to transformer failure; and increases in transformer failures. Based on Company-provided information, Table I identifies that as transformers failures have increased, customer complaints have also increased.

Table I: Complaints Related to Transformers (July 2003, 2002, and 2001)[22]

Category	July 2003	July 2002	July 2001
Transformer-Related PUC Complaints	**111**	**65**	**13**
Total Delivery[23] PUC Complaints[24]	280	205	59
Percent Transformer of Total Delivery	**40%**	**32%**	**22%**
Total Transformer Failure	**556**	**414**	**315**

[20] Presentation to Staff on August 20, 2003. It is unclear if the Company's measure represents an outage frequency percentage or an outage duration percentage.
[21] Staff requested that the Company update this data for years subsequent to 1998. The Company's response is still pending.
[22] Transformer Load Management Program, presentation to Staff and OCC, November 20, 2003.
[23] The Delivery Unit is the work group within Xcel Energy, Inc. that is responsible for delivery of utility resources effectively and efficiently to customers.
[24] Does not include complaints for such things as billing errors.

The issue of customer outages caused by PSCo's distribution system is not a new issue to the Commission. The October 13, 1998, *Report on Staff Investigation of Public Service Company of Colorado Power Outages*, while focused on a series of transmission system outages from July 17, 1998 through July 20, 1998, also addressed in a separate section outages related to distribution infrastructure. Specifically, in the Executive Summary of the Report, related to engineering and operations, Staff concluded:

> *". . . Also, on a going-forward basis, the continued use of transformer retirement data to determine whether replacements are required seems to increase the risk of customer outage. A more proactive method of assessing transformer loading might be better."* [25]

The body of the Report identified concerns about transformer replacements more discretely. Staff reported:

> *"As we stated in Attachment DI-2, PSCo began in 1998 to place only transformers of at least 50 kilovolt ampere (KVA) in serving customers located in subdivisions. We were also informed by PSCo that in 1997 it had discontinued its program to monitor distribution transformer loading by computer analysis of monthly energy consumption. (In this process, the computer program converts monthly energy consumption into a demand value for all customers connected to the transformer and generates an exception report if the value exceeds some percentage, e.g., 25 percent, of the maximum capacity of the transformer.) PSCo personnel stated that they were now monitoring the transformer retirement logs to determine whether there was an abnormal number of retirements in each maintenance service area."*[26]

Staff further goes on to discuss its concern over PSCo's method of screening whether distribution transformers are overloaded after initial placement of the transformers:

> *"We also have some concern about PSCo only relying on the transformer retirement log to gauge whether its distribution line transformers are being overloaded.*

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[25] *Colorado Public Utilities Commission Report on Staff Investigation of Public Service Company of Colorado Power Outages,* October 13, 1998, Executive Summary p. x.

[26] Ibid, p 27.

> *PSCo offered no insight into how the retirement logs will be used to proactively determine that transformers are being loaded too heavily and should be replaced. While this may be viewed as a form of "diagnostic maintenance," i.e., waiting to reach until more than the normal amount of transformers fail, it could leave more customers to experience outages before a replacement program is undertaken. Unless PSCo can more fully define a proactive maintenance policy in relying on transformer retirement data, it should consider reactivating some version of its computerized monitoring program or undertake some type of statistically-based sampling program in which measurements are taken of some distribution line transformer loads periodically."*

The Company does not dispute that the number of customer outages related to the failure of distribution transformers is increasing, does not dispute that these outages are increasingly frustrating to its customers, and consequently are a major cause of the increase in customer complaints to the Company and to the Commission. However, the Company has struggled with finding a satisfactory solution to this issue.

B. The Joint Staff/OCC Inquiry

The most current inquiry actually began informally during the summer of 2002. As a matter of its normal practice, Staff periodically reviews the Company's service results. As it reviewed the Company's annual QSP report for calendar year 2001, which was filed in the spring of 2002, Staff became concerned with the increase in customer complaints during the 2001 summer peak-load period (usually July-August). PSCo attributed this increase in complaints to both an increase in construction-related cable cuts and to increased load on transformers for air conditioning. Staff identified its concerns in its report to the Commission and committed to work with PSCo to reverse the trend.[27] At about the same time articles in the media about summer 2002 neighborhood outages confirmed Staff's concerns.

Staff began by initiating a series of audit questions about PSCo's efforts to maintain reliability. The first audit questions were sent to the Company on July 19, 2002. Answers to these questions revealed that components of PSCo's distribution

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[27] *Verification Report Electric Quality of Service Plan Results for Public Service Company of Colorado Calendar Year 2001,* p. 10, Docket No. 95A-531EG.

system, and in particular failing distribution transformers, were foremost contributors, but not the sole contributors, to summertime outages.

Answers to these initial audit questions also caused Staff to request a series of meetings during the summer and fall of 2002 with PSCo regulatory and managerial personnel to resolve the issue.

Staff initially met with the Company's reliability team on Friday September 12, 2002, about these and other distribution system outages and transmission service issues. At this meeting, PSCo described problems with its distribution system and acknowledged that its policy was to replace transformers only after they failed multiple times, causing recurring outages for customers served by the problem transformers.

Additionally, during this meeting the Company agreed with Staff that while SAIDI is a good tool to monitor overall system and regional system outages, it is not a robust tool for identifying localized problems such as distribution transformer outages. The Company also agreed that customer complaints provide an important source of information in gauging the reliability of the system. The Company also committed to begin a focused effort to minimize distribution transformer outage duration because the increasing rate of complaints concerning these types of outages was a concern to them as well as to Staff.

Ultimately, through continued meetings and discussions, the Company developed a two-tiered approach to minimize distribution transformer outage time during the 2003 summer load. The Company created a Distribution Transformer Team (Team) to investigate root causes of consumer complaints in Colorado and to recommend solutions to mitigate those complaints. At these meetings the Company presented its Distribution Asset Optimization (DAO) model, software that endeavors to identify problem transformers using quantitative methods so problem transformers could be replaced before they failed. Throughout these discussions, PSCo advocated that wholesale replacement of transformers is not cost effective and that replacing only problem transformers will maintain the reliability of the distribution system without excessive cost to customers. The efforts of the Distribution Transformer Team and the DAO model are described in more detail in the following subsections.

C. The Distribution Transformer Team

The Distribution Transformer Team for the Denver Metro Area was comprised of two operations managers, one standards manager and three engineers. Specifically, after its review of outages, the Team identified that during 2002, 874 transformers had been replaced, with over 60 percent (526) being replaced during June, July and August (peak load periods). For 2002, the time associated with replacing transformers was as follows:

Table II: Transformer Replacement Times (2002)

Transformers Replaced in:	Percent (%)
Same Day	36%
1-3 Days	29%
4-7 Days	6%
8-31 Days	10%
> 1 Month	19%
Total	100%

To improve 2003 performance, the Team established the following goals:

- *Replace within one week a transformer that went out due to overload but is placed back in service by replacing the fuse or resetting a secondary breaker; and,*
- *Replace the internal transformer fuse on a single-phase pad mount transformer with the next larger size, but schedule the transformer for replacement within one week.*

In addition, the Team implemented the following process changes for 2003 to track the type and status of work and potential problem transformers:

- *Use the Request for Outage (RFO)*[28] *to process work orders rather than the existing system;*
- *Place a tag on the transformer or pole when an overloaded transformer is placed back in service by re-fusing or resetting the breaker;*

[28] A Request for Outage (RFO) is an internal PSCo document requesting specialized work assistance for a particular task.

- *Move the RFO for its replacement to "immediate status", even if the problem transformer can temporarily be placed back in service if the fuse goes out again.*

Finally, the Team's goals to manage its labor resources included:

- *Establishing round-the-clock crews (three shifts) that replace transformers and respond to emergencies;*
- *Developing a response plan for days when major transformer outages occur;*
- *Using contract crews to replace transformers and respond to emergencies during peak load periods when the transformers are most likely to fail;*
- *Arranging for improved equipment availability;*
- *Using all Metro-area crews and crews from outside the Metro area, when necessary to respond;*
- *Hiring new linemen in the Trouble Department for the summer before deploying the linemen to the divisions; and*
- *Establishing a system to track and respond to aging RFO's.*

D. The Distribution Asset Optimization (DAO) Model

The DAO is a Silicon Energy model that is designed to link Customer Information System (CIS) data, data from the Supervisory Control and Data Acquisition System (SCADA) including meter reading data, automatic meter reading (AMR) data, local weather information, and other system data to create an integrated time and weather synchronized distribution database. The goal of the model is to allow the Company's distribution planning, operations, and asset managers to manage their work based on more robust system demand information.

Specifically, related to distribution transformers, the model's design planned to develop coincident load profiles for all transformers. The design was intended to provide hourly detail by transformer, which would be used to understand the actual condition of equipment over time, not just at peak use.

Generally, as an asset optimization tool, the model's goal is to identify assets that are either "under-utilized" or "over-utilized". Conceptually, assets that exceed utilization targets ("over-utilized") are identified and fixed or replaced accordingly. Contrarily, assets that do not meet utilization targets ("under-utilized") are identified and targeted for deferred maintenance or left in service longer.

The Company's engineers hypothesized that the DAO model's measure of fully loaded equivalent hours of electric usage by transformer would predict transformer failure. The model identified 1,298 candidate transformers for replacement based on four target areas of the Company's serving territory based on transformer usage. Three hundred candidate transformers (of the 1,298) in two of the four areas were field verified and then replaced. The remaining 998 were classified as the "control" group.

E. The Results For 2003

During the summer of 2003, PSCo again experienced transformer-related distribution outages and customer complaints to the Commission.

A comparison of outage information for the months of July for three consecutive years reveals the following information:

Table III: Results of Company's 2003 Plan (July 2003, 2002, 2001)[29]

Category	July 2003	July 2002	July 2001
Total PUC Complaints for Company's Delivery Unit	280	205	59
Transformer Related PUC Complaints	111	65	13
Percent Increase in Transformer Related PUC Complaints (year-over-year)	**71%**	**500%**	--
Percent Transformer Complaints of Total Delivery Complaints	40%	32%	22%
Total Transformer Failures	556	414	315
Percent Increase in Transformer Failures	**34%**	**31%**	--
NOAA Warmest July ranking (1872-2003)	4	9	6
Number of days over 90/100	23/3	22/0	18/1

Comparing 2003 results with 2002 results suggests that overall the Company ***has not*** made sufficient progress to solve this problem from a customer's perspective. Transformer-related complaints increased from 65 to 111, an increase of almost 71%. Total transformer failures increased by 142, from 414 to 556, an increase of 34%. This compares to an increase of 99, or 31%, from 2001 to 2002.

[29] Source: Transformer Load Management Presentation to Staff and OCC, November 20, 2003.

While the hotter weather of 2003 may have contributed to the increase (see NOAA rankings, and number of days over 90/100 in the chart above), and while some of the increase in complaints may be attributable to increased publicity concerning the issue, the bottom line is that total transformer failures continued to increase. As a result, Staff and OCC believe that customer complaints related to this issue are likely to increase and escalate if the problem is not solved.

Staff and OCC met with the Company's Reliability Team on August 29, 2003, to evaluate the effectiveness of the Company's 2003 Plan and to discuss the Company's efforts prior to 2004.

In summary, the Company reported that its efforts to quickly replace transformers after the first outage had significantly reduced multiple interruption and long duration outages. The Company reported a 25% reduction in multiple transformer outages (2003 vs. 2002). However, while the efforts of the Distribution Transformer Team likely mitigated the 2003 summer impacts of transformer outages, the Company reported that the DAO model effectiveness was only 3.5%.

After evaluating the Company's efforts, we conclude that changes in policy during the summer of 2003 to replace transformers that fail due to overload conditions and to classify such replacements as a high priority mitigated repeat customer complaints and likely reduced complaints compared to what they would have been if the policy had not changed. However, we also conclude that the Company's efforts in this area should be expanded, at least until an effective program to proactively identify problem transformers and other distribution equipment can be implemented.

F. The Next Step: The Company's Initial Proposed DAO Model for 2004

As a result of the relative ineffectiveness of the DAO model for the summer of 2003, the Company decided not to expand its replacement plan based on the same DAO model and proposed an alternative model prior to the upcoming 2004 peak.

This new proposed model was based on information gleaned from the 2003 DAO model including: analysis of outages and weather showed failures increased after multiple days of hot weather; nearly all outages involved fuse elements immersed in the insulating oil in the transformer tank and that high oil temperatures can affect the trip levels of the fuse; and, nearly all outages involved transformers with both electrical and thermal limiters. The Company's initial proposal was to predict candidate transformers based on "hot spot temperature" calculated by the DAO.

While the Company's presentation on its "hot spot temperature" model was based on an understanding of how distribution transformers function and operate, Staff and OCC were greatly concerned when the Company shared its projected model efficiency rate of only 4.3 percent. We were concerned that this model would be no more effective at solving the customers' problems than the previous predictive DAO model (3.5 percent).

The Company's presentation also identified that underground transformers were involved in approximately 66 percent of the total outages, with overhead outages accounting for the remaining 34 percent. For the overhead outages, almost all outages involved completely self-protected type transformers, an older style of transformer.

For both overhead and underground outages, the number of transformers that failed varied by distribution transformer size as summarized in the following Table:

Table IV: Percent of Transformer Failures

Size (KVA)	Underground	Overhead	Total
<= 15	--	5%	5%
25	48%	26%	74%
50	14%	2%	16%
>= 75	4%	1%	5%
Total	66%	34%	100%

When this data is compared to data that identifies the percent of overall transformer population by size, a disproportionate share of transformers that are failing are transformers of smaller sizes as identified in the following table and transformers that are placed using underground construction appear to be more problematic than transformers that are placed overhead:

Table V: Percent of Transformer Failures for Underground and Overhead by Size[30]

Size (kVA)	Underground (Failures)	Underground (Population)	Underground to Population Ratio
25	48.0%	24.2%	**2:1**
50	14.0%	18.7%	.7:1
75	1.0%	3.8%	.25:1
>=100	3.0%	4.1%	.77:1
Total	66.0%	50.8%	1.3:1
Size (kVA)	**Overhead (Failures)**	**Overhead (Population)**	**Underground to Population Ratio**
<= 15	5.0%	3.3%	1.5:1
25	26.0%	21.7%	1.2:1
50	2.0%	5.7%	.33:1
>= 75	1.0%	3.2%	.33:1
Total	34.0%	33.9%	1:1

This type of macro information suggests to Staff and OCC that the Company must either discretely identify the population of 25 kVA transformers that are problematic, or alternatively evaluate its policy of targeted replacement and explore whether a systematic target long-term replacement plan for 25 and below KVA transformers is necessary. It is noteworthy that in the *Report on Staff Investigation of Public Service Company of Colorado Power Outages, October 13, 1998* the Company's minimum standard transformer size for subdivision installations was 50 kVA.[31]

As an alternative to the Company's proposed DAO Model, Staff's engineering personnel proposed that PSCo pursue a simple, but direct, comparison of transformer nameplate[32] capacities with

[30] Source: Transformer Load Management Presentation to Staff and OCC, November 20, 2003, p. 3.

[31] *Colorado Public Utilities Commission Report on Staff Investigation of Public Service Company of Colorado Power Outages,* October 13, 1998, p. 27.

[32] A nameplate rating is a manufacturer's classification of a transformer's certified load serving capacity as measured in kilo-Volt-Amperes (kVA) under specific ambient temperature and operating conditions. Usually the rating is established for continuous service under stressed operating conditions of hot summer temperatures such as 35°C and allows for a 65°C rise in temperature of the insulating oil. However, a transformer thus rated is capable of safely operating at a higher output if the load lasts only for a short period of time or if the ambient temperature is cooler. For example, in the cold winter

likely transformer loads in order to locate transformers overloaded and likely to fail. This is similar to the method that was in place in the early 1980’s to detect transformers that were potentially overloaded. As a result of concerns about the effectiveness of the Company’s proposed “hot spot DAO model”, the Company agreed to review its proposal and update Staff and OCC after it reviewed whether this was the most effective method of solving the problem. In addition, the Company agreed to make a comparison of loads and distribution system transformer nameplate ratings serving these loads as an alternative or supplemental information to identify problem transformers. The Company agreed to provide this information by December 1, 2003.[33]

On November 20, 2003, Staff and the OCC again met with PSCo to discuss the Company’s modeling efforts. The Company identified that its candidate replacement list for 2004 focused on replacement of overhead and underground 25 kVA distribution transformers. The Company represents that its new proactive transformer model replacement program based on “hot spot temperatures” is five times more effective than choosing candidates for replacement at random.

In the model proposed by the Company, “hot spot temperatures” are used to rank the replacement candidates for 25 kVA transformers. Additionally, based on engineering judgment, candidates are selected based on the number of customers assigned to transformers. The Company proposes to refine its selection process further but it is not yet completely specified and not yet tested. PSCo committed to identify problem transformers for replacement during the spring of 2004. The Company also identified at the meeting that it may not spend the full $3 million dollars it committed to spend on the “hot spot transformer” replacement program, but may shift those dollars toward solving other reliability issues because it may be more cost effective.

The Company did not provide to Staff and OCC, as requested, the comparison of loads and distribution system transformer nameplate ratings serving these loads. Rather, the Company

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months a typical 25 kVA transformer can routinely handle 75 kVA in load each night if the load only lasts for one hour. On the other hand, on a hot summer afternoon when the temperature is 95°F (35°C) this same transformer will tolerate only 25 kVA of load for the 4-hour duration of air conditioning load.

[33] PSCo response to Staff audit Reliability8-9.

decided that it would use frequency of failure information as a substitute for such information.

G. The Company's 2004 Reliability Action Plan

At the November 20, 2003, meeting Staff and OCC requested that the Company provide details of the Company's dollar commitments for 2004. The Company provided its *2004 Reliability Action Plan for Colorado* (Attachment 3).

The Company identifies $22.9 million in expenditures. The majority of the expenditures focus on a proactive underground cable replacement program ($10 million)[34] and on-going vegetation management activities ($6.6 million).

It also identifies that $2 million of the $3 million proactive distribution transformer replacement commitment has been reassigned to reduce outages resulting from substation and distribution devices that have experienced three or more interruptions in the last year, rather than proactively replacing transformers. The Company plans to use the remaining $1 million to replace 600 transformers prior to July 2004.

With the $2 million that the Company proposes to redirect, the Company intends to reduce the number of frequent interruptions caused by the same devices including substation circuit breakers, and distribution line re-closers, sectionalizers, transformers, and tap fuses. The Company represents that the devices experiencing three or more interruptions in the last year will be assigned to area engineers to determine the reason for multiple interruptions and to mitigate the problem. The target is to reduce the number of these devices experiencing three or more interruptions by 30 percent in 2004.

H. Transformer Outages Summary

Based on Staff and OCC's review, it concludes that the work of the Company's Distribution Transformer Team did mitigate the outage time related to failing transformers during the summer of 2003, particularly in the area of repeat outages. If the Team had not taken action, we believe that the customer outages would have been worse, and complaints greater. Additionally, Staff concludes that the Company's DAO modeling efforts were only marginally effective at identifying problem transformers.

[34] $7.5 million of proactive underground replacement and $2.5 million of emergency underground replacement.

Further, it is not clear that the “new” DAO modeling effort will be any more successful than the previous efforts based on the information received to date.

Further, we conclude that unless the Company develops an alternative program to identify transformers that are overloaded based on customers’ demand for power, customers will likely continue to experience unnecessary outages and customer complaints to the Commission are likely to remain high and will continue to increase. Unfortunately, development of such a program will likely take time.

Consequently, in the short-term, we recommend that the Company continue and expand the Distribution Transformer Team’s work to include timely repair and replacement, if necessary, of other equipment in addition to transformers. As additional data has been reviewed, we conclude that it is not only transformers but also other equipment components that can cause the recurring and frequent failures. Additionally, until effective preventive and predictive models are implemented, it may be necessary for the Company to return to its former practice of assigning a larger number of distribution engineers than are currently employed to monitor and effectively maintain the distribution system.

However, an action plan based solely on the work of Teams such as the Distribution Transformer Team remains a plan based on failure first and not a proactive (prior-to-failure) measure. Staff and OCC do not believe such a plan is sufficient to meet the growing need for power by customers in Colorado. Rather, we believe it is necessary for the Company to develop and implement a systematic preventive maintenance program to identify and replace distribution transformers and other equipment components that can no longer effectively meet customer demand.

Consequently, we recommend that the Company develop and present to the Commission an action plan that addresses both issues- how to manage the system until preventive maintenance programs are effectively implemented, as well as the development of an effective long-term plan to identify where demand in distribution areas is exceeding equipment capacity and the program the Company will use to upgrade its infrastructure where that demand exceeds capacity.

We recommend that the Company formally present its plan to meet these goals to the Commission at a special meeting to be held sometime during February of 2004. This will permit the Company the flexibility to design its own best solutions to resolve these problems, but will also hold the Company accountable to its customers for results.

II. Whether the Company's Systems and Engineering Practices are Adequate to Identify Inadequacies in Distribution Infrastructure, Particularly in Older Neighborhoods

A. History and Trends

Recurring complaints about outages (especially extended and/or multiple outages in the same neighborhood) often indicate problems with the ability of a utility to provide reliable service. While the previous section focused on distribution transformer outages during peak load periods, the historical complaint data suggests that the Company has repair issues outside the peak period as well. Specifically, the customers' repair complaints to the Commission have increased 137% from 2002 through November 2003. Separating the summer peak time period (July and August) from the remainder of the year identifies that non-peak complaints have increased at a rate even higher than complaints during the July and August peak-period months.

Table VI: Repair Complaints During Peak and Non-Peak Times

	2003 YTD (through Nov)	**2002**	**% Change**
Repair complaints excluding July & August	675	161	**319%**
Repair complaints in July & August	339	266	**27%**
Total Repair Complaints	1014	427	**137%**

Some, but not all, of this 2003 increase is likely attributable to the March and May storms of 2003.

Additionally, an analysis of Commission outage complaint data from records maintained by the Consumer Affairs organization for fiscal years 2002-2002, 2002-2003, and the first half of fiscal year 2003-2004 identifies that chronic outage complaints are increasing at an alarming rate. Staff reviewed all PSCo's complaints that were coded "Repair" for these 2½ years and evaluated their content to determine if either the consumer indicated a problem with chronic outages, or the Company response indicated that chronic failure of a component or components was the cause of the consumer's concerns. The results of that evaluation indicate that the complaint rate doubled between fiscal year 2001-2002 and fiscal year 2002-2003. The complaint rate is on track to more than double again for fiscal year 2003-2004 if it continues at its rate during the first half of the fiscal year.

Table VII: Repair Complaints Identifying Repeated Outages

	Fiscal Year 2001-2002 (July 1, 2001- June 30, 2002)	**Fiscal Year 2002-2003** (July 1, 2002- June 30, 2003)	**6 Months of Fiscal Year 2003-2004** (July 1, 2003- Dec. 31, 2004)
Total PSCo Chronic Outage Complaints	149	301	380
Percent Increase	--	102%	152%[35]

During the spring and summer of 2003, two areas were particularly problematic – a neighborhood in South Denver and parts of Centennial.[36]

The "South Denver" issue was officially raised to the PUC by customer contacts to the Commission's Consumer Affair's organization in the early summer of 2003. Three customers representing two households, and a group of almost 100 customers collectively, via a petition, sought assistance because the Company was not adequately addressing their service outages. Broadway Street on the west, Grant Street on the East, Louisiana Avenue on the north, and Asbury Avenue on the south generally bound this South Denver neighborhood.

Individual customers contacting State Representative Lauri Clapp initiated the Centennial issue after the Mother's Day Weekend storm in May 2003. Representative Clapp, as an advocate for her constituents, contacted the PUC Director to request his assistance in expediting restoration efforts. Some of her

[35] Calculated as ((380x2)-301)/301 based on an assumption that outages in the second 6-month period will equal the outages during the first 6-month period.

[36] This is similar to a problem that occurred in the Bonnie Brae neighborhood during 2002. A review of PUC External Affairs files during July and August of 2002 identified approximately 46 of PSCo's customers in the neighborhood complained about service outages. Most, if not all, of these complaints were generated when portions of PSCo's distribution system failed during hot weather.

constituents were facing financial loss from food items thawing due to a lack of power to their freezers. Others faced emergency medical conditions with a loss of power to the home. Others simply felt frustrated with the recurring outage problems in their neighborhood.

The data gathered on these two neighborhoods is enlightening and explained more fully in the following subsections.

B. The South Denver Customers' Experience

As stated previously the "South Denver" issue was raised to the PUC by customer contacts in the early summer of 2003. Three customers representing two households and a group of almost 100 customers collectively, via a petition, sought assistance from the PUC because the Company was not adequately addressing the issue.

The first of the three customers contacted the PUC's Consumer Affair's organization on May 30, 2003. Inquiries by PUC Staff to the executive office of the Company identified that the customer had 11 outages from April 16, 2002 until July 8, 2003. Six of those 11 outages were classified as momentary outages (less than one minute). Based on PSCo's response to the PUC inquiry, three of these six momentary outages were attributed to either lightning and thunderstorms or wind. The remaining three momentary outages were classified with the cause unknown. Of the five remaining non-momentary outages, all were classified as fuse 05/56 with the corrective action on all to re-fuse. For these five outages, the clearance time ranged from 81 minutes to 1,880 minutes, with an average clearance time of over two hours.[37]

As a result of the Consumer Affair's informal investigation for this customer, the Company committed in a July 9, 2003 letter to the staff member to patrol the customer's area to prevent animal and weather interference. A staff member transmitted this information to the customer on July 10, 2003. However, the customer further contacted the staff member on September 6, 2003 identifying continued problems and indicating that a neighbor was circulating a petition on power outages. The letter stated:

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[37] This calculation of two hours includes a clearance time of 157 minutes on April 24, 2003 that was reported initially in PSCo's response as 1,570 minutes. Validation against the neighbor's outage history report indicates only 157 minutes. In response to Staff audit the Company confirmed that the correct duration time was 157 minutes, not 1,570 due to an input error by Company personnel.

> *"My neighbors and I have experienced an unreasonable number of power outages during the period 2000 to present. These outages are in excess of one per month.*
>
> *"Xcel states that many of these failures are cause (sic) by squirrels, trees, or weather. An in depth look, I believe will reveal that most outages are cause (sic) by equipment failure, due to inadequate and insufficient maintenance and lack of resources provided by the corporation. . . .*
>
> *". . . Now back to my problem at [address removed]. I believe and my investigation shows that the high voltage transformer at Jewell and Acoma Streets in South Denver is* ***badly over loaded****. It has no tolerance and trips a live circuit resulting in an outage to the entire neighborhood it supplies. It is always the same houses, same traffic lights, etc.*
>
> *"The transformer referred to above needs replacing with one with the capacity to handle the larger load and the distribution network may need reworking.*
>
> *"During several outages in our area, I've been able to talk to Xcel people in Wisconsin and Minnesota about the location of the fault. Almost always the transformer at Jewell and Acoma is listed as the reason for the outage."*

The other two customers (representing one household) presented a petition to David M. Wilks, President of Xcel's Energy Supply market unit with a copy to both Directors Smith and Reif along with a number of legislative, media, and Company contacts on September 8, 2003. The petition included signatures of residents in the 1300 through 1600 blocks of South Sherman Street and South Grant Street and also a few businesses located on South Broadway between those two streets.

The outage history report for these customers indicated 11 outages from March 17, 2003 through October 8, 2003. Two of those 11 outages were classified as momentary outages (less than one minute). One of these was attributed to lightning and thunderstorms with a breaker trip and re-fused (June 17, 2003); the other was also classified as breaker trip and re-fuse but with cause unknown. Of the nine non-momentary outages, all were identified as fuse 05/56 with the corrective action on all to re-fuse and attributed to weather or cause unknown. For these nine outages, the clearance time ranged from 134 minutes to 1,880 minutes, with an average clearance time of 2.7 hours.

In addition to problems similar to the first customer, the second customers' letter identified issues with PSCo's customer service and its follow-through on promises made to its customers. Particularly troublesome are the following:

- A customer service representative committed in March to have a manager contact the customer and that did not occur;

- The Company assured the customer in early June that the transformer had been replaced and that did not occur; and

- A Company representative whom they finally talked with on August 31 committed to check out the situation with his engineers and get back to the customer within a week and that return contact did not occur.

The investigation into this issue basically confirms the customers' allegations that the Company was aware of the problem and did not take adequate actions to resolve the problem. The Company's response states:

> *"Due to frequent outage complaints, PSCo linemen patrolled the neighborhood during the last week in May. The result was an order to Vegetation Management to trim trees in one location and an order to repair a cross arm at another location.*
>
> *"Complaints from the neighborhood continued and on 8/4/03 Work Request ("W/R") #6005 (Attachment Reliability8-2.A1) was created to replace several cross arms.*
>
> *"On 8/20/03, PSCo's Area Engineering patrolled the neighborhood again and W/R #6156 (Attachment Reliability8-2.A2) was created to repair a transformer with a burnt bushing.*
>
> *"When it became apparent that previous patrol efforts had not discovered the root cause of the problem, Area Engineering requested on 9/05/03 that the Line Department re-patrol the area. A lineman inspected*

> *the area and returned with notes containing customer comments and some additional repair suggestions. W/R #6778 (Attachment Reliability8-2.A3) specified that a crew should inspect all B phase insulators and other equipment on every pole from the air using a bucket truck and repair all problems found.”*

It appears from documentation provided that the original commitment to the customer (in May) to replace a cross arm was not completed until after multiple additional complaints were received. In response to Staff audit requesting the Company provide ***all*** documents that show the extent of investments, measured in dollars, PSCo/Xcel made in the last year to prevent reoccurrences of outages in this neighborhood, the Company’s response only showed investments occurring after August 20, 2003 with the majority of dollars spent during September 2003. The Company ultimately replaced five cross arms, 2 transformers, 25 primary glass insulators, five lightning arrestors, and added wildlife protection.

It also appears that despite the Company’s commitment to the first customer to patrol the area during July to prevent animal and weather interference, the activity to address these issues did not begin until late August and was not complete until late September.

Summarizing the history for fuse 05/56 based on these two customers’ outage histories identifies that this fuse blew 11 times from April 16, 2002 until October 8, 2003 (a period of slightly less than 17 months), which in Staff’s and OCC’s assessments are a demonstration of inadequate service. It certainly is outside the Company’s new proposed standard to review equipment failures causing three or more interruptions within a year.

Further, it is not apparent why necessary repairs, especially repairs such as replacing “old brown glass insulators” and replacing “<u>many</u> old brown arrestors” (emphasis in original),[38] should require Company personnel on-site four times and why it should take from May to September to get fixed. While it may be that weather and animal activities caused the initial outage, continued re-fusing and patrolling doesn’t appear to be an effective way of solving the problem.

[38] PSCo response to Reliability8-2.A3, handwritten page 4 of 4.

C. The Centennial Customers' Experience

The issue related to Centennial customers was first brought to the attention of the PUC when State Representative Lauri Clapp contacted Mr. Smith, Director of the PUC following the storm on Mother's Day weekend in May 2003.

Representative Clapp, along with many of her neighbors, had been without power for days during the Mother's Day storm. Typical of spring snowstorms in Colorado, the snow was heavy and wet with moisture. Newspaper accounts reported seven inches of snow throughout the metropolitan Denver area.

This Mother's Day storm was the second time in less than two months that many of these customers were without service for multiple days. During March of 2003 (March) a major storm caused an accumulation of approximately three feet of snow accumulation throughout the metropolitan area. During this March storm, many of these same customers were without power for 2-4 days.

Representative Clapp's issue was escalated to the executive offices of the Company. Subsequent to restoration of power to the customers, the Company met with Representative Clapp, Commission Staff and OCC to discuss service issues in Centennial.

As a result of these and subsequent discussions, the Company's executive level personnel agreed to attend a neighborhood meeting for Centennial customers to directly address customers' concerns. In preparation for the meeting, the Company initiated a postcard type questionnaire to customers in the neighborhood to solicit issues impacting the neighborhood.

The issues identified in response to the questionnaire, while focused on the March and May storms, included other issues as well. The customers' concerns included:

1) Failures in the Restoration Process During the March and May Storms:

- *Time to restore service was excessive during storm;*
- *Restoration prioritization inconsistent with Company policy - entire blocks remained out for multiple days;*
- *Company's recording of outages is inconsistent with customers' experiences;*

- *Excessive restoration times cause loss of property –food and pets;*
- *Credit for service interruptions should be issued; and,*
- *Failure to give a high priority to customers with emergency medical conditions.*

2) Communication Failures During the Storms:

- *Service representatives located out-of-state were not informed of local conditions in Colorado;*
- *Accurate restoration times were not provided;*
- *Customers had to contact representatives multiple times before outages were fixed;*
- *The Company's system had not associated the customer's correct address with his/her phone number;*
- *The hold time to report outages was excessive, sometimes measuring in hours, not minutes.*

3) General Concerns of the Customers:

- *Time to restore service is excessive, even without storm conditions;*
- *Outage frequency is excessive, even without storm conditions;*
- *Reasonable and logical explanations of the immediate problem are not provided (squirrels cannot cause that much damage; our lines are underground so the Company's explanation that tree branches are the cause doesn't make sense; storm conditions cannot be the sole cause because we have outages beyond the storm;) and the recording of those problems is suspect;*
- *Quality of repair work is bad.*

Immediately after the Company's initial discussion with Representative Clapp, the Company internally began investigating the causes of the extended outages for the Centennial customers. In the course of that investigation, the Company discovered that miscoded customer information in parts of Centennial was a major contributing factor to the outage times experienced by these customers. The Company also initiated action to modify some of its internal practices to address customer concerns. Each of these is discussed in succeeding sub-sections of the Report.

1) Failures in the Restoration Process During the March and May Storms

The Company's goal in restoring power to customers is to repair power lines and equipment as safely and as rapidly as possible. The Company's policy in restoring power is to give top priority to situations that threaten public safety, such as downed power wires. The Company then prioritizes repairs based on what actions will restore power to the largest number of customers most quickly.[39]

In general the Company repairs transmission lines first because they serve the largest number of customers. These high-voltage lines carry electricity in bulk from the power plants to regional substation that may serve one or more communities. Feeder lines, major power lines that serve thousands of customers, are generally repaired next. The Company then prioritizes tap lines, which serve residential neighborhoods and businesses and serve from 40 to several hundred customers. The lowest priority, in general, is given to individual service wires, which carry power from a tap line to a home or business.[40]

In addition, as a backstop to these general restoration guidelines, the Company has internal procedures for customers experiencing extended outages. When a customer reports that he or she is experiencing an extended outage, that call is routed to a customer service representative. The representative verifies that an outage report has been generated, and checks the status of the previous order in the Company's Customer Information System (CIS), which tracks customers' contacts with the Company. If an order was sent, the representative contacts its resource management organization to gather further information regarding the event and it places a call to the appropriate Control Center[41] to determine the status of the job. Based on the judgment of the Control Center personnel, the extended outage order may be prioritized above outages that impact a larger group of customers but have a shorter duration time.[42]

These restoration procedures (both general and extended outage reports) are highly dependent on the accuracy of the Company's

[39] PSCo response to Reliability6-8.A11.
[40] Ibid.
[41] The Control Center is the work unit that dispatches technicians to fix problems.
[42] PSCo response to Reliability3-1.

records that map the Company’s transmission lines, feeder lines, tap lines and service lines to customer locations. If the customer location is incorrectly mapped or if a feeder or tap line is inaccurately coded as an individual service line rather than as a tap or feeder line, the Company may incorrectly prioritize the service restoration.

The Company currently uses “Power On” Outage Management System (OMS) as its computer application tool to geographically locate and analyze electric service outages. It integrates or “connects” data from the Company’s Geographic Information System (GIS) and address information from its Customer Information System (CIS).[43] The GIS system, in turn, is a database that relates physical equipment in the field (circuit breakers in substations, transformers, fuses, switches, re-closers, primary opens, etc.) to geographic locations.

However, during both the Mother’s Day Storm and the March storm, inaccuracies in the Company’s OMS system directly contributed to degraded outage response time in the Centennial area. Two separate and distinct issues contributed to the degraded response time: inaccuracies in the OMS database and un-located calls.[44]

The first issue, inaccuracies in the OMS database, contributed to the more than 1,956 trouble calls from the Centennial area alone during March 2003 and more than 2,208 trouble calls during May 2003. OMS did not recognize that some reported outages were in the same general area because the OMS connectivity process indicated these outages were single customer in nature. Single reports of outages were assigned a low priority. As a result, OMS could not and did not aggregate the reported outages and predict a probable device that caused the outage. Consequently, a low priority was assigned to these outages and the outages were responded to only after all other feeder, tap and transformer outages were repaired.[45]

The second issue, un-located calls, also contributed to degraded response time. Incorrect GIS mapping or incorrect outage call information created instances of outages being un-located. The total number of un-located trouble calls from Centennial in March 2003 was two. The total number of un-located calls from Centennial in May was 15.[46]

[43] PSCo response to Reliability7-1.
[44] PSCo response to Reliability7-4.
[45] PSCo response to Reliability7-4.
[46] PSCo response to Reliability7-4.

It should be noted that the above call counts are likely significantly understated because they do not include records that were lost when OMS system resets were performed on March 19, March 25, and May 13th. A system reset wipes the database clean clearing out all existing records, specifically those that have not been closed and archived to history. On the dates noted, OMS became overloaded with trouble calls.[47] This overload degraded the system to the point that it became unusable by PSCo personnel. The reset was necessary to free up system resources to allow the dispatchers to effectively use the system.

In addition to the problems identified in the Company's OMS, the normal extended outage procedures were not followed during the Mother's Day storm. During the storm, there were too many orders to use the normal process for customers experiencing extended outages. Instead, these orders were faxed to the Control Center and were manually analyzed to verify the cause of the extended outages. While this break down in extended outage procedures may have contributed to the degraded response time, it is unclear how much more chaos this added to the Control Center during the Mother's Day storm after the OMS was reset.[48]

Subsequent to the Mother's Day storm and discussions of the Centennial outages, the Company reviewed and modified its procedures related to the GIS. During the month of May 2003, a team of 10 people checked every GIS circuit for connectivity errors. The analysis increased the number of customers connected to each circuit.[49] As a result the outage minutes reported to the PUC prior to this "connectivity" review are understated. However, the magnitude of the understatement is at issue.

Upon additional review, PSCo representatives acknowledged that the problems related to OMS were not unique to the Centennial area.[50] The detected problems include: when a circuit is added or modified in the GIS, the connectivity between equipment and customer elements does not always build out properly; part of a circuit may not be completely built out; and the outage prediction feature may fail if multiple pathways back to the

[47] The Company believes that many of these calls were repeat calls. However, Staff can neither confirm nor dispute that belief at this point in time.
[48] PSCo response to Reliability3-3.
[49] PSCo response to Reliability7-5.
[50] PSCo response to Reliability7-9.

substation source are created due to revisions to existing circuits or the addition of new circuits.[51]

In addition to the May 2003 review for connectivity errors, the Company has added a new analysis tool on a limited basis to test the GIS connectivity model. The tool traces an entire circuit without as much human intervention, which makes it easier to detect and resolve errors. However, the Company uses it on a limited basis because it takes more time.[52]

The inaccuracies in the Company's systems are particularly troubling. If the basic equipment and customer information coded in the systems are not accurate, the Company's trouble restoration will be both ineffective and inefficient and will likely result in unnecessary outage minutes for PSCo customers. In addition to degrading customer restoration times, inaccurate database information impedes the analysis to determine why repeat distribution outages occur and may result in inaccurate remedies through the existing QSP.

Equally troubling is the veracity of the Company's OMS system as evidenced by "resetting" the system on March 19, March 25, and May 13th.[53] On May 10, prior to resetting the system, PSCo documentation suggests that the OMS system was operating 5.5 hours behind meaning accurate and timely prioritization and outage information was backed up for 5.5 hours.[54] While Colorado customers in some areas of the state may agree that the March of 2003 storm was unusual, Colorado customers would likely classify the Mother's Day storm as typical of Colorado spring storms. If PSCo's system cannot manage the call volume from a typical spring Colorado storm, the OMS system may be inadequately sized.

The Company stress-tested the OMS system in February 2003. While the Company was able to provide a copy of the test procedures used to stress test the system, and while the Company states that the results were acceptable to the testing team and the "user community"[55], no criteria for "pass" or "fail" was included as part of the testing procedures, no basis for the volumes tested was provided, and no documented test results were

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[51] PSCo response to Reliability7-10.
[52] PSCo response to Reliability7-6.
[53] PSCo response to Reliability7-4.
[54] PSCo response Attachment Reliability7-15.A2, email message at 1:54PM.
[55] Staff is seeking clarification of the "user-community", as Staff is unsure exactly who the "user-community" represents.

maintained for external review.[56] (See Attachment 4) In Staff's and OCC's assessment, such a testing process does not comport with accepted testing methods for any system, let alone a system so critically important to the Company's day-to-day operations.

The test included generating 2200 calls in 30 minutes to the system and running the test for several hours.[57] During the timeframe from May 9, 2003 through May 13, 2003, there were 41,663 outage calls originating in Colorado. These 41,663 calls represented about 51 percent of the total calls the Company received during this same period.[58] The Company has informally indicated that it has modified the structure of the system to relieve congestion, but has not provided data to demonstrate that its modifications allow it to effectively operate when customer contact volumes are high.

In addition to the frustrations expressed by the Centennial customers, many may have suffered financial hardship directly or indirectly as a result of the extended outages. Staff attempted to contact Centennial customers in late December as part of this inquiry. As part of those contacts, Staff asked the responding customers if they had filed claims with the Company for damage restitution. Most indicated that they had not. Of those who initially expressed interest in filing a claim, most said the requirements were either overwhelming or required documentation that they had not retained. The one customer responding who had filed a claim indicated that the claim was denied due to lack of sufficient documentation.

2) Communication Failures During the Storms

Customers from Centennial also indicated that they did not receive accurate estimated restoration time information.

When a customer inquires about an outage, a customer representative queries the OMS to determine if there is a reported outage at the customer address. If there is an outage the representative can view a field titled "Estimated Repair Time" (ERT) and the order status, which has three designated fields (unassigned, dispatched and arrived). The representative is also able to view the date and time a trouble order was initiated and dispatcher comments. The ERT field is calculated based on customer call patterns and a probable outage source device. If a field technician believes it is going to take a

[56] PSCo response to Reliability7-7.
[57] PSCo response to Reliability7-7.
[58] PSCo response to Reliability4-2.

longer amount of time to restore service than predicted by the OMS, the technician can have the dispatcher update the ERT field. However, the OMS does not notify the representative regarding updated ERTs. The representative must query the system to find an updated time.[59]

Prior to May 29, 2003, all outages in the Denver metro area were assigned a four-hour restoration estimate except during high outage volume periods. During these high volume outage days the Company used "threshold" estimates of repair time to provide customer service representatives with a general idea of how long crews were taking to make repairs. Control Center personnel determined the threshold by analyzing the outage data, including the number of escalated outages and the number of feeder, tap, and transformer outages. Historically, the thresholds were defined as:

- Threshold 1 = Up to 8 hours;
- Threshold 2 = Up to 16 hours;
- Threshold 3 = Up to 24 hours; and,
- Threshold 4 = Greater than 24 hours (Outlook update provide estimated repair time).[60]

Staff and OCC conclude that the OMS problems described in the previous subsection significantly contributed to the miscommunication during the March and Mother's Day storms. When the OMS system was reset, key information used to establish estimated repair times was lost. If this information was not available, customer representatives viewing the ERT field in the system were viewing times estimated on inaccurate and incomplete data and consequently may have misinformed customers. Consequently, it is difficult to evaluate whether the historical threshold system used by PSCo is inherently flawed based on the Centennial experience or whether the OMS problems compounded the communication problems beyond the control of the representatives.

Subsequent to May 29, 2003 the Company modified its practices relating to reporting of estimated restoration times. Subsequent to May 29, 2003, all outages except high outage volume periods in the Denver metro area are assigned restoration estimates based on a table that uses historical data and the level of predicted outages (feeder, tap, transformer, single customer) rather than assigning a standard four-hour estimate.

[59] PSCo response to Reliability7-11.
[60] PSCo responses Reliability7-12 and 7-13.

These estimates identify a range of restoration times from two to five hours, depending upon time-of-day, weekend or holiday, and type of equipment (re-closer, sectionalizer or fuse, transformer, or single). These estimates are made available to the CIS so that customers can receive an estimate via the Integrated Voice Response (IVR) or a customer representative. The threshold process described earlier was still used for high outage volume days.[61]

In an effort to improve the information conveyed to customers, the Company has also added an alarm feature within OMS to automatically alert dispatchers when an existing outage job is nearing its estimated restoration time. This alarm alerts the dispatcher to update the estimated restoration time in OMS. After the dispatcher updates the estimated restoration time, the customers can receive the updated time information either via the IVR or a customer representative.[62]

In September 2003, PSCo discontinued use of the threshold process for high outage volume days because it believed the blanket restoration estimates were not optimizing its communications with its customers. Now, the Control Center sends specific information including the communities involved and an estimated repair time to the Call Center via email. The Company believes that the new process allows PSCo to localize the estimates to outage locations rather than applying blanket estimates to the entire metropolitan area.[63]

Centennial customers were also frustrated with the lack of Colorado location-specific knowledge demonstrated by customer representatives located outside of Colorado. It is Staff’s and OCC’s understanding from discussions with Company personnel that the Company is evaluating ways to effectively share Colorado weather information with its remotely located call centers. We recommend that the Company detail this in its February presentation to the Commission.

Centennial customers also expressed concerns that the Company’s outage records are inconsistent with customers’ experiences. The OMS problems (both “connectivity” errors and the system resets) contributed to discrepancies. However, the OMS problems may not be the only problem as is discussed later in this report.

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[61] PSCo response to Reliability7-13 and Attachment7-13.A1.
[62] PSCo response to Reliability7-13.
[63] PSCo response to Reliability7-13.

Finally, a critical issue evaluated was the effectiveness of the Company's communication with critical care customers and with life support customers. When a commercial customer that offers essential medical services requests electric service from PSCo, the Company identifies the customer as a "Critical Care" customer based on the services that the customer provides.

Residential customers must make application with PSCo to be designated a "Life Support" customer. After the application is received, the Company sends a letter with a verification form instructing the customer to deliver the form to the customer's health care provider. The provider or the customer then sends the form to the Company and the medical equipment described in the form is compared to a list of approved life support equipment. If the support equipment is on the approved list, the customer is designated as a "Life Support" customer. The designation is re-verified annually in the same manner as the original verification.[64] As of October 2003, the Company has 611 Life Support customers.[65]

Company employees in the call centers, credit departments, field collections departments, and personal account representatives inform customers of the Critical Care and Life Support designations. Agencies providing energy assistance that work directly with the account representatives also inform customers of these designations.[66]

The Company's CIS system has a screen devoted to identifying Life Support customers and can be viewed by all customer service representatives. In addition, a Life Support Seal on the electric meter housing identifies Life Support customers at the customer location.[67]

When a "Critical Care" or "Life Support" customer calls in and reports an outage either through the integrated voiced response system or through a customer service representative, the designation in CIS is automatically transferred to the Control Center through OMS. In this case the trouble order is flagged as affecting a Critical Care/Life Support customer.[68]

The Company's processes do not detect a Critical Care or Life Support designation when a customer in close proximity to a

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[64] PSCo response to Reliability 7-18.
[65] PSCo response to Reliability7-22.
[66] PSCo response to Reliability7-19.
[67] PSCo response to Reliability7-16.
[68] PSCo response to Reliability7-16.

Critical Care or Life Support customer makes an outage call.[69] While customer service representatives have a listing of emergency services for all major cities, there is no link from the customer representative to the 911 system[70] and PSCo has no formal procedure for communicating to emergency agencies that a Critical Care or Life Support customer may be at risk from a power outage.[71] Critical Care and Life Support customers are not notified about changes in estimated restoration time.[72]

Based upon the answers to audit questions, there are specific concerns about procedures PSCo employs to communicate with and to provide expedited reconnection to customers at risk. These concerns include:

- It is unclear that customers know how to get placed on PSCo's Critical Care and Life Support list.
- It is unclear what process is used for contacts with emergency agencies when Critical Care or Life Support customers are at risk from a power outage.
- It is unclear if PSCo has appropriate contingency procedures to address Critical Care and Life Support customers in the event its OMS or CIS systems fail.
- It is unclear if PSCo has appropriate procedures for Critical Care and Life Support customers when the Company expects extended outages to occur or when the time of an outage is extended.

The Company has reviewed and changed some of its practices concerning communications with critical care customers but has not yet provided details of those changes.

It is recommended that the Company be required to make available for the Commission's, Staff's, and OCC's review any modified practices concerning communications with critical care customers and customers on life support and to address the specific concerns above. We recommend that, if necessary, this report on the issue should be supplemented after that review.

3) General Concerns of the Customers:

In addition to the specific concerns related to the storms, Centennial customers expressed significant concerns not directly

[69] PSCo response to Reliability7-17.
[70] PSCo response to Reliability7-20.
[71] PSCo response to Reliability7-21.
[72] PSCo response to Reliability7-23.

related to the storm. As stated previously, these concerns included: time to restore service is excessive, even without storm conditions; outage frequency is excessive, even without storm conditions; reasonable and logical explanations of the immediate problem are not provided and the recording of those problems is suspect; and, the quality of repair work is bad.

These concerns are virtually identical to the concerns expressed by the South Denver neighborhood, which were discussed in detail peviously.

As part of the inquiry, Staff contacted the three individual members of the South Denver customers and a sample of the Centennial customers[73] by phone survey in late December of 2003 to ascertain if the Company had tried to follow-up with these customers after the Centennial meeting to ensure that the customers' concerns had been resolved.

The contacted South Denver customers indicated that they had received correspondence from the Company, but that the correspondence did not identify what specifically was fixed. These customers reported that there had been no significant outages since September 2003 subsequent to the Company's repair activities, which corrected a number of problems.

For the Centennial customers responding to the Staff's phone survey, the results are as follows:

[73] Based on customer contacts identified in PSCo's response to Reliability6-9.

Table VIII: Staff Survey of Centennial Customers

Parameter	Statistics
The percentage of customers contacted by Company after July 29, 2003 Centennial Town Meeting	43%
The percentage of customers reporting the Company provided them a plan to fix the problem(s)	22%
After the town meeting, the percentage of customers reporting that service was:	
Better	62%
Worse	0%
Same	24%
Too Early to Tell	14%

The general reaction of the Centennial customers was that after the Town Meeting, the Company did not contact them to identify how the problems were specifically fixed. Some contacted said that the frequency or duration of outages had diminished, but that they were unsure if it was due to decreased loads or because the Company had actually fixed the underlying problems.

In summary, Staff and OCC conclude that the Company's response to customer concerns in South Denver and parts of Centennial identify that the Company is, at least in some cases, not adequately identifying and responding to recurring and extended outages by customers without intervention by external advocates.

It is not clear if the Company's responses in South Denver and parts of Centennial are isolated events; however, the history of increased repair complaints to the Commission and the outage frequency of customers initiating those complaints suggests that executive level intervention in this area is necessary. Review of Commission complaints[74] related to chronic outages indicates that other neighborhoods in addition to the South Denver and Centennial areas reported chronic outage concerns. These neighborhoods include: Denver- Bonnie Brae, Belcaro, and near 3600 South Holly Street and 4600 Yosemite Street; Aurora- areas of South Hannibal Street and East Center Avenue; Arvada- West

[74] From July 1, 2001 through December 31, 2003.

83rd Avenue and West 75th Place; Westminster- West 92nd Avenue; Golden- West 60th Avenue, and Littleton- Sundown Ridge.

While the Company’s *2004 Reliability Action Plan for Colorado* (discussed in the previous Section) suggests that the Company may now be trying to focus additional resources on “frequent outage” situations, it is not clear that the Company isn’t pulling resources from the proactive transformer replacement program to push this new effort, rather than doing both and resolving both. Unless the Company can convince the Commission that it can do both effectively, we recommend that the Commission require the third-party engineering assessment described below.

To resolve these issues, we recommend that the Commission require a focused performance assessment by an independent third-party engineering and management firm at the Company’s expense to evaluate the effectiveness of the Company’s existing engineering and operational practices to fix problems that are causing frequent and extended customer outages. As part of this assessment, the third-party firm should evaluate whether the Company’s preventive maintenance practices comport with best industry practices and should recommend areas for improvement if deficiencies are identified.

Further, we recommend that the Commission use quantitative gauges to monitor the Company’s progress and performance toward achieving these goals.

PSCo should publicly present its plan to meet these goals to the Commission in February of 2004 and should provide monthly written progress updates beginning in April of 2004.

III. How PSCo Communicates With Customers During Outages and Determine Whether Customers Are Receiving Current and Adequate Information

A. Introduction

In order to fulfill its statutory charge of ensuring reliable electric service the Commission must obtain reliable data that shows the performance of the Company. If the data are inaccurate, incomplete, or biased, the Commission’s decisions may be based on a foundation of sand.

More important, however, if the data are inaccurate, incomplete, or biased, the ***Company's*** decisions may be based on a foundation of sand leading to bad management decisions and negative customer impacts, thereby damaging the public interest. It is critical to remember that the information that the Commission needs to monitor the Company's performance is the same information the Company requires to effectively manage its business. If the information that the Company's customers or the Commission is receiving is incomplete, the Company's management may also be receiving incomplete information.

The example of extended outages for Centennial customers caused by inaccurate or incomplete OMS data is an example of how inaccurate and incomplete data in the Company's systems directly impacts Colorado customers. Centennial customers indicated that the outage information provided by the Company was not consistent with their own personal experiences. South Denver customers shared similar experiences. In large measure the customers suggested that more outages had occurred than the Company identified.

As a result of "resetting" the OMS system over Mother's Day weekend and during the March storm, and as a result of the inaccuracies and incomplete "connectivity" data included in the Company's databases, it is not surprising that customers are reporting outage discrepancies between their records and the Company's records *because the Company's records were incorrect and incomplete*. While the Company's position that records of trouble calls to the Company are not impacted by a system reset in OMS is correct,[75] it does not portray the entire picture. The OMS system creates a history of any distribution equipment failures. Consequently, the loss of OMS data eliminates records of outage information that are used to provide information to another system that then is used to report outages to the Commission and to customers. Additionally, the customer's restoration priority is affected by an OMS reset.

Staff researched two other potential issues related to data discrepancies in conjunction with this inquiry. First, in mid-July of 2003, Staff analysts at the Commission had informal discussions with the Supervisor of the Commission's Consumer Affair's unit, who indicated that an increasing number of customers who had contacted the PUC believed the Company's records of system outages were incomplete and inaccurate. As a result of these informal discussions, the Supervisor agreed to

[75] PSCo response to Reliability7-4.

flag and track customer comments related to this issue for a defined period of time.

Second, on August 4, 2003, the Office of the Attorney General (MN OAG) and the Department of Commerce (MN DOC) in Minnesota submitted to the Minnesota Public Utilities Commission (MPUC) a third-party audit of Xcel's service quality reporting records by Fraud*wise*, a division of the accounting firm of Eide Bailly LLP. It was unclear if the systems and methods, practices and procedures used by NSP to report outage information were similar or identical to systems and methods, practices and procedures used by PSCo. It was also unclear whether PSCo's operations might be similarly impacted by the Fraud*wise* audit.

These two issues are addressed in subsequent subsections of this report.

B. Data From Consumer Affairs Unit

As indicated previously, the Supervisor of the Commission's Consumer Affairs organization began in mid-July 2003 to flag and track customer comments regarding PSCo's electric outage records for a period of time.

In a typical complaint the customer contacts the PUC regarding chronic and/or lengthy electric outages that have negatively affected a residence or business. As is practice pursuant to 4 CCR-723-3-16, the Company responds to the PUC inquiry with requested information about specific outages, and usually includes outage history reports when available or appropriate.

In correspondence to a member of the inquiry team, the Supervisor identified the problem as follows:

> *"In what I would characterize as a significant number of cases filed since mid-May, customers were compelled to re-contact the PUC following their review of the outage and/or repair information provided by Xcel to the PUC. The follow-up almost always disputes the Xcel record as being inaccurate to the benefit of the Company."*

In situations such as these, a PUC complaint specialist who receives this type of follow-up contact inquires if the customer would like to file an addendum to the inquiry with the Company regarding the record. In cases where the customer requests further information the specialist opens an addendum and inquires further. In most cases the customer does not request further PUC inquiry, but requests that the PUC memorialize their disagreement with the Company's record.

The Supervisor also noted that the inquiries did not appear to come from an apparent central source, but rather from a broad spectrum of locations around the Denver metro area. The Supervisor attached a list of 12 contact identification numbers from the Commission's internal tracking system, the customers' names, addresses, and detailed correspondence from both the customer and the Company. The inquiry team's review of these customers' records is summarized in the following table with the resolutions coded below. Codes that underestimate the time originally reported to the customer are identified **in bold typeset**:

Table IX: Outage Reports – Customer vs. Company

Contact ID #	**Customer's Report of Outages**	**Company's Original Report of Outages**	**Results of Inquiry's Teams' Review (see code table below)**
52086	Customer complaints about outages and reporting;	5 outages averaging over 3 hours in duration during period of Jan. 2002 through May 2003; March and May storms times not identified even though Company correspondence to customer suggested storms contributed to outages.	**Code 2**, Code 5
52254	Estimates had approximately 15 non-momentary outages during that time;	4 outages averaging over 5 hours in duration.	**Code 3**

Table IX: Outage Reports – Customer vs. Company (cont.)

Contact ID #	Customer's Report of Outages	Company's Original Report of Outages	Results of Inquiry's Teams' Review (see code table below)
52622	Lengthy outages on 3/28, 3/29, 3/30, 3/31 and 5/14 not identified in Company's list; additional outage after June also.	5 outages averaging over 5 ½ hours during period from March 2003 through June 2003; did not include March storm outage.	Code 5, **Code 7, Code 9**
52839	Missing March storm outages of 65 ½ hours and missing 2nd outage on one day of 8 hours and 10 minutes. Also reports five outages lasting more than 3 hours since April 2001.	2 outages averaging over 3 hours from Jan 2003 through July 2003; Discussion of May storm in correspondence to customer, but no times identified.	**Code 3, Code 6, Code 9**
52842	Power outages with storms occur frequently; Power out for 4 days during March storm; Two additional non-momentary outages for about 1 ½ and 3 hours;	2 outages with an average duration of over 3 hours from Jan. 2003 through July 2003; One was during March storm but showed outage time of just over 4 hours;	**Code 9**

Table IX: Outage Reports – Customer vs. Company (cont.)

Contact ID #	Customer's Report of Outages	Company's Original Report of Outages	Results of Inquiry's Teams' Review (see code table below)
53090	Original complaint was recurring power outages; Dispute that problem is fixed because outages continue to occur.	Field personnel found a voltage regulator that had been struck by lightening causing short daily outages; One of the outages was while Company was replacing the regulator; Further patrol found re-closer that was causing momentary outages; removed and sent in for maintenance;	No discrepancy.
53129	Chronic outages; Add'l times: 7/11/03: 2 hrs 7/2/03: 2 outages; one for 5+ hrs; one for 6+ hrs; 7/3/03:3 ½ hrs; 6/23/02: 3 ½+ hrs; 6/24/02: 3 hrs; 6/28/03: two outages for 2 ½ hrs total; 6/29/03: two outages for about 3 hrs total.	7 outages averaging over 4 ½ hours each plus 5 additional momentary outages from Jan 2003 through July 2003; Same fuse 4 of seven times; other fuse 2 of seven times;	**Code 2, Code 3, Code 8**

Table IX: Outage Reports – Customer vs. Company (cont.)

Contact ID #	Customer's Report of Outages	Company's Original Report of Outages	Results of Inquiry's Teams' Review (see code table below)
53172	One outage showed duration of about 5 hours, but customer indicates duration was about 15 hours.	4 outages for average of over 4 ½ hours;	**Code 2, Code 4**
53318	Customer disputes final report from the Company because it suggests the transformer was replaced on July 15, 2003; Customer discussed with responders who indicated that fuse was replaced on July 8th; trouble again on July 14 replaced with larger fuse and tagged for replacement; Same replacement tag continues to be there.	Company indicates replaced transformer that was causing chronic problems.	Accuracy of communication to customer in dispute;
53784	Disputes time on outage log; Customer says outage was 9 hours, not 4 hrs.	4 outages averaging almost 5 hours during period from Jan 1, 2002 through Dec. 19, 2002	--

Table IX: Outage Reports – Customer vs. Company (cont.)

Contact ID #	Customer's Report of Outages	Company's Original Report of Outages	Results of Inquiry's Teams' Review (see code table below)
53965	Power outage of 16 hours from 8/8/03 through 8/09/03; Told worked throughout the night, but techs told customer they just started in the morning; Averages a power outage every two months; Customer disputes August outage; power restored just after noon, not 12:40 am as reported by Company.	7 outages averaging over 3 hours in duration during period of August 8, 2002 through August 10, 2003.	Code 1, **Code 2**
54046	Customer out for about 33 hours; disputes Company's time; indicates not restored until 5pm the next day.	Company responded to outage reported early am on August 8^{th}. Required special crew which restored service that evening; Trouble men responded to outage reported at 12:48 pm. Power restored at 2:46 pm.	Unclear if second restoration was on the 8^{th} or the 9^{th};

Missing outages are particularly problematic because if an outage occurs but it is not recorded, it understates the Company's analysis of its own outages – both frequency and duration. Further, it distorts the Company's reporting to the customer and the Commission, and potentially understates the financial remedies given to customers as part of the Company's QSP.

In response to apparent inconsistencies between customer's records of outages and PSCo records of outages, Staff requested additional information in an effort to reconcile the outage records. The Company indicated that there were several reasons why the reports submitted to the PUC by the Company's representatives compared to that received from the customer did not reconcile.[76] Bottom-line, Staff and OCC conclude that customers' time estimates are more accurate than the Company's time estimates for these outages. Highlighted **in bold typeset and coded by number** are the reasons that resulted in the understatement of outage minutes to customers and to the Commission. These reasons include:

1. *The complaint specialist initially only asked for a list of all "customer complaints" and did not ask for a list of all outages; consequently, five outages over a period of approximately seven months were not included in the Company's outage list to the PUC;*
2. ***Reports (five outages on four customers) submitted to the PUC were inaccurate because the Company had delayed putting the outage information into the Generic Outage Entry System (GOES) database;***
3. ***Reports (three outages for three customers) submitted to the PUC were inaccurate because the Area Engineer responsible for researching outages either misread the data in the GOES database or missed a device because he or she was unaware that the device serving the address had been switched;***
4. ***Misunderstanding by Engineer (two outages for one customer) as to what he or she should extract from the database; he or she only extracted 2003, when the customer's information also included 2002 information;***
5. *Company records (two outages for two customers) indicate that no outages occurred at the listed addresses on the dates in question and consequently there is no outage information included in the GOES database; additionally, the Company's customer service representative made general remarks indicating that he or she contacted the customer (in one case by phone, in one case by mail) in response to a previous outage;*
6. ***The Company records indicate that a trouble call generated a single customer outage report; however, the order was canceled by dispatch because a call back to the customer indicated that service was restored. No outage information was entered into GOES because***

[76] PSCo's response to General Audit 2003 CPUC4-1.

this appeared to be a situation in which the re-closer operated;[77]

7. ***Company records in the CIS indicate that a customer was without power, but CIS does not contain a Trouble Order for this customer for this date (one outage for one customer);***
8. ***Company records indicate outage information in CIS, but not in GOES (two outages, one customer); the Company believes that this may be attributable to errors associated with manually entering outage information into the GOES database; and,***
9. ***During the March and Mother's Day storms, the Control Center personnel reset OMS resulting in a loss of start times for outages that had not been closed.***

In summary, for this small sample of twelve customers, Staff and OCC conclude that the customers' history of outages is more accurate than the information extracted from the Company's system. The sample revealed at least twelve discrepancies attributable to the Company's systems in addition to the impacts from resetting the system during the March and Mother's Day storms.

However, it is important to consider that this sample for 12 customers is small, and is not random. Rather, it was extracted from a pool of customers who complained that the Company's records were not accurate or were incomplete. Consequently, it is not appropriate from a statistical perspective to extrapolate this inaccuracy and incompleteness to the entirety of PSCo's reported outages or to PSCo's reporting for all customers. We conclude that there are indicators the Company's outage reporting to customers and to the Commission may be understated and that additional investigation is warranted. Based on the review and the acknowledgements of the Company explained later in this section, it is reasonable to recommend that additional review in this area is prudent.

It is important to note that during the timeframe of the joint agency inquiry, the Company modified its methods, practices, and procedures for tracking outage data for SAIDI statistics reported to the PUC. Prior to August 23, 2003, the GOES databases (one for Denver/Boulder and one each for PSCo's geographic regions) was the sole source of data for the SAIDI statistics reported to the PUC. On August 1, 2003, OMS became

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[77] If it is a single customer outage report, it suggests that it is a distribution (not a feeder) outage; consequently, it is unclear why this type of outage would not be entered into the system.

the sole source of outage information for the Denver/Boulder area for below-feeder[78] outages. The Company made the change to eliminate the manual process of data entry for each Denver/Boulder outage that was not a feeder line. This change in PSCo's system may eliminate some of the data disparities going-forward, but will not eliminate all such disparities.

While the data validity issue needs to be further investigated, there is a need to not lose sight of why the outage information is important. It is important because it is a signal that a problem may exist. If frequent outages occur, there may be some equipment problems causing the outages. Staff and OCC are very concerned that the frequency of outages identified in its review of these customers is excessive and supports conclusions that the Company's responsiveness to frequent and extended outages needs improvement.

C. Integrity of Information Similar to Minnesota

As stated previously on August 4, 2003, the Minnesota Office of the Attorney General (MN OAG) and the Minnesota Department of Commerce (MN DOC) submitted to the Minnesota Public Utilities Commission (MPUC) a third-party audit of Xcel's service quality reporting records prepared by Fraud*wise*, a division of the accounting firm of Eide Bailly LLP.

The audit firm concluded:

> *"…the records supplied for review are unreliable and appear to have been manipulated to ensure favorable SAIDI results."*

The firm further concluded:

> *"The overall reporting system for outages at Xcel does not appear to be the cause of duration misstatements. Problems have been created by a small number of employees entering inaccurate information into the system, thus resulting in unreliable outage reporting. Throughout this investigation Fraudwise has found Xcel to have very dedicated employees whose main concerns lie in the quality of service provided by Xcel."*

[78] Below-feeder outages are outages on the customer-side of the substation. These are tracked in OMS, while feeder and above outages are tracked separately to account for partial restoration times.

On September 24, 2003, the MN DOC, MN OAG- Residential Utilities Division, and Northern States Power Company (NSP), d/b/a Xcel Energy, collectively submitted to the MPUC a settlement agreement to resolve the issues in a proceeding. It was unclear from the information identified in the Stipulation if the systems, methods, practices and procedures used by NSP to report outage information were the same systems, methods, practices and procedures used by PSCo.

The Colorado Staff and OCC joint inquiry investigation began by attempting to understand the differences and similarities between the outage reporting processes in Minnesota and Colorado. First, the outage measures reported between the states differ. In general, the reporting requirements in Minnesota are greater than the requirements in Colorado.[79] In particular related to system interruptions, Minnesota requirements include the following in addition to SAIDI and System Average Interruption Frequency Index (SAIFI)[80] reporting requirements:

- CAIFI (Customer Average Interruption Frequency Index);
- Number of customers experiencing six or more repeated and sustained interruptions;
- Dollar amount of customer remedies;
- Action plans for failure to meet SAIDI, SAIFI, and CAIFI requirements;
- Bulk power interruption incident reporting; and,
- Worst performing circuit information by work center.

In addition to different measures used by the states, different parameters exist within the measures. For example, the NSP-MN SAIDI calculations include outages greater than five minutes, include secondary outages but exclude transmission outages. PSCo’s SAIDI calculations for Colorado include outages greater than one minute, include some transmission outages, but exclude secondary outages. Storm exclusions are calculated differently for each state.

The systems used to gather and collect outage information also differ between the states. The following tables summarize the similarities and differences in the systems as identified by the

[79] PSCo Response to Reliability6-1. Note that the response indicates it was provided on 8/27/02, but since the question was not presented until August 14, 2003, it is assumed the Company meant 8/27/03.
[80] In Colorado, SAIFI is identified in PSCo’s QSP, but is not used to calculate financial reparations.

Company on August 27, 2003.[81] Differences are highlighted in bold type.

Table X: Similarities and Differences Between Minnesota and Colorado Metro Denver/Boulder[82] Below-Feeder Outage Reporting Systems

Denver/Boulder Metro Areas	Minnesota
Customer calls and reports outage to Xcel call center;	Similar
Customer service representative routes call to Outage Management System (OMS) where call is analyzed and job is created.	Similar except **use of Distribution Dispatch System (DDS)**
OMS job info includes timestamp of the first customer call along with other pertinent info. **This timestamp is used for calculating the start time of SAIDI.**	Similar **but timestamp is not used for calculating the start time of SAIDI.**
OMS job is made accessible to a First Responder. Job remains open in that as additional calls and comments are received from customers, the priority level can escalate.	Similar
OMS system contains information regarding connectivity of system allowing discernment of whether outages are common to particular circuits.	Similar
A Dispatcher assigns the job to a First Responder and the dispatch time is electronically stamped.	Similar
The First Responder initiates a standard trouble ticket (paper) and records the date, address, assigned time, outage level/device, and other useful information provided by the Dispatcher.	Similar
Upon arrival at the customer location, the First Responder records the arrival time and begins the outage assessment and the restoration process.	Similar
If the First Responder can restore service, the First Responder records the restored time, proper cause codes, confirms the level of outage, and adds any comments that are needed for clarity or follow-up. The First Responder's time is the time used in the SAIDI calculation.	Similar except DDS **and no notation that the First Responder's time is used in the SAIDI calculation.**

[81] See response to Reliability6-2. Note that the response indicates it was provided on 8/27/02, but since the question was not presented until August 14, 2003, it is assumed the Company meant 8/27/03.

[82] The Metro Denver/Boulder information is collected and processed through the Outage Management System. Other Colorado regions are collected and processed differently.

Table X: Similarities and Differences Between Minnesota and Colorado Metro Denver/Boulder[83] Below-Feeder Outage Reporting Systems (continued)

Denver/Boulder Metro Areas	Minnesota
This restoration information is called into the Dispatcher and recorded as part of the OMS job. The OMS job is closed and time-stamped in OMS.	Similar except DDS.
At the end of the shift, the First Responder turns in trouble tickets to Delivery Management.	Similar **but does not identify whom the trouble tickets are turned into.**
Later, the trouble tickets are compared to the OMS information. **If necessary, the OMS information is corrected to be consistent with the restoration time on the First Responder's trouble ticket.**	Later, the trouble tickets are compared to the DDS information, **approved and filed to the Reliability Monitor System (REMS) thus becoming a part of the outage records. Discrepancies in restoration times, cause codes, outage levels, and/or other comments can be reconciled or added at this point. The department management or their designee does this reconciliation. The Company states that this is important to provide accurate outage data including duration, cause, level, follow-up, database corrections, etc.**
If the First Responder cannot restore service, the Dispatcher refers the job to an area construction department or another group to restore service using info from the First Responder.	Similar
The area construction department or other group then becomes responsible for restoring service to the customer(s) and recording the restoration time used in calculating SAIDI.	The area construction department or other group then becomes responsible for restoring service to the customer(s). **Depending upon the time of day and the day of the week, the restore time may or may not be recorded by the local area dispatcher or control center dispatcher. Because many of these events occur outside of regular business hours, these outages may be reconciled during the next business day. The referred DDS job is reconciled with info from the restoration crew, approved and filed to REMS by the local area dispatcher or manager.**

[83] The Metro Denver/Boulder information is collected and processed through the Outage Management System. Other Colorado regions are collected and processed differently.

Table XI: Similarities and Differences Between Minnesota and Colorado Feeder Outage Reporting Systems

Denver/Boulder Metro Areas	Minnesota
Outage at this level begins when the feeder breaker in the substation opens. The control center personnel receive an alarm via the SCADA system from the substation indicating that the breaker has opened along with the time of this occurrence. In the Denver/Boulder area, the time stamp in SCADA is the start time of the SAIDI calculation.	Similar **except the time stamp in SCADA is not used.**
The Dispatcher dispatches a First Responder to begin patrolling the feeder to locate the cause of the outage.	Similar except **control center personnel rather than a Dispatcher performs the function.**
The First Responder initiates a standard trouble ticket and records the feeder number, assigned time and any other useful info.	Similar.
In Denver/Boulder the Dispatcher enters a feeder outage into OMS creating an outage job to capture all attributes for that respective feeder including outage time, customer count, etc. This OMS action also prevents another Dispatcher from dispatching below feeder outages on that specific feeder. This is necessary because there is no electronic tie between the OMS and SCADA, and OMS only analyzes customer outages to below feeder level.	Similar **except DDS and control center personnel rather than a Dispatcher perform the function.**
In general, the feeders are constructed in such a manner that when a fault occurs on some part of the feeder there are switches that can be used to isolate the faulted section and restore service to unaffected sections. Depending upon the situation, the Dispatcher usually directs the First Responder to perform those tasks. The result is that, in many instances, various parts of the feeder are restored at different times. The First Responder records on the trouble ticket the various times that these switches were operated.	Similar **except control center personnel rather than a Dispatcher.**
In the Denver/Boulder metro area, the Dispatcher enters the outage start and restoration times in a Request for Outage Report (RFO). The start time is the SCADA time and the restoration time is from the trouble ticket. In the Colorado geographic area, the field trouble ticket alone is used to create an electronic outage record in the GOES database for reliability reporting purposes.	**The control center operator then fills out a RFO, which records when various switches were operated in the course of restoration. The operator also fills out a Disturbance Report that captures some of the same info in addition to follow-up requirements, substation breaker info, restoration times, percentages, etc. The DDS job created for the feeder outage is normally completed using the info from the RFO form and the disturbance report. The job is then filed to REMS.**[84]

[84] REMS is Minnesota's Reliability Monitor System.

Table XII: Similarities and Differences Between Minnesota and Colorado Final Data Quality Check and Indices Calculations

Denver/Boulder Metro Areas	Minnesota
Prior to August 2003, in the Denver/Boulder metro area, the Control Center Manager or designee manually entered the OMS archived outage database contents into the area's GOES database. Subsequent to August 1, 2003, the OMS archive became the sole source of outage information for the Denver/Boulder Metro area for below feeder outages. In each Colorado geographic region, trouble ticket information is manually entered into an area's individual electronic GOES reporting database.	
Prior to outage information being submitted to the CO PUC, a data analyst sorts the GOES databases to identify outage entries that appear to be in error. Delivery Management (or a designee) investigates these outages by reviewing the available data and researching the event. Delivery management (or a designee) may change GOES entries if there is assurance that the entries are made in error. **Note that the Company did not identify if this changed after August 1, 2003.**	Similar **except MN PUC instead of CPUC and REMS instead of GOES.**
To complete the reliability indices, a data analyst exports the various GOES database contents into an Access database where a series of macros are run to generate information in accordance with the CO PUC's criteria for reliability reporting (e.g. major storms, events shorter than 1 minute, etc.)	To complete the reliability indices, a data analyst exports the various **REMS data contents into a FoxPro database** where a series of macros are run to generate information in accordance with the MN PUC's criteria for reliability reporting (e.g. major storms, **events shorter than 5 minutes**, etc.)

In general it appears that there are more stringent system time and management controls in PSCo's reporting system as compared to the Minnesota reporting system. In particular, there appears to be less possibility for management intervention to override the system, particularly post-August 2003 when the manual entry into GOES for below-feeder outages was eliminated. The use of time-stamps to record start times provides a standard and common form of system control. However, without reviewing the detailed methods, practices and procedures involved in each of the processes and without a performance audit of each system, it is difficult to judge whether one operation in practice is superior or inferior to another.

Subsequent to the issuance of the Fraud*wise* report in Minnesota, PSCo initiated an internal management review of its own operations both within and outside of the Denver/Boulder metro area. PSCo provided its documentation of the review supporting its non-Metro operations. The results are summarized in the following Table:[85]

Table XIII: Summary of Non-Metro Outage Tickets

Division	Tickets Examined	# Tickets Found in Error	Percent of Tickets Found in Error	Errors of Dates or Times	Percent of Tickets with Time or Date Errors
Mountain	8	8	100%	4	50%
San Luis Valley	22	10	45%	6	27%
Front Range	7	6	86%	2	29%
Grand Junction	21	6	26%	1	5%
Rifle	3	3	100%	0	0%
Sterling	4	3	75%	0	0%
Fort Collins	6	1	17%	0	0%
Greeley*	NA	NA	NA	NA	NA
Total	**71**	**37**	**52%**	**13**	**18%**

* Documentation problem. No outage forms.

The error rates in the first three regions are unacceptable and the sample sizes are too small by area to conclude that there are no identified problems within the areas. The lack of information for Greeley is unexplained.

The Company delayed providing its review of the Denver/Boulder metro area. In mid-December of 2003, the Company requested a special meeting with the Staff and OCC to acknowledge that its own internal review of the Metro Denver area identified that its system underreported outage times in its reports filed with the Commission. During the mid-December meeting, the Company identified that a copy of its review would be forthcoming.

Based on information shared at the December meeting, the resetting of the Company’s OMS during the March and Mother’s Day storms caused some underreporting of outages. Other underreporting was caused by inaccurate and incomplete information in other systems linked to the OMS. Some of these are identified in this inquiry, but others need to be further explored by Staff and OCC. While some of the underreporting (OMS resets) may be limited to 2003 data, it is unclear at this time whether the under-reporting also impacts previous reporting

85 PSCo response to CPUCReliability 6-6.

periods. The magnitude of the impact has not yet been identified.

In summary, we conclude concerns about not receiving adequate and current information during winter and spring snowstorms of 2003 are legitimate. The Company's normal prioritization and dispatch activities were not possible because of the resetting of the Company's OMS and inaccurate "connectivity data". These dispatch and prioritization irregularities significantly contributed to the Company's inability to effectively communicate and respond to customers during and subsequent to the March and Mother's Day storms of 2003. Inaccurate and incomplete "connectivity" data in the Company's systems also contributed to the extended outages in the Centennial area during the March and Mother's Day storms of 2003. This "connectivity" data problem identified for the Centennial area impacted the entire Metro area, but is unclear how pervasive a problem the Metro-area inaccuracies represent.

PSCo's management may not have performed adequate system stress testing of the OMS system to ensure that it was adequately sized to operate under typical storm conditions. While the Company has recently indicated that it modified its system to prevent such reoccurrence, it is unclear if such modifications are adequate. It will likely require expertise outside the current expertise of Staff and OCC to make an objective assessment as to whether the system is adequately sized.

In addition to system problems (resetting the OMS system during the storms, incomplete and inaccurate "connectivity" data), other operational and administrative issues are likely contributing to an understatement of reported customer outage occurrences. The magnitudes of these understatements are indeterminate at this time.

Further, and importantly, it is unclear whether the Company's normal day-to-day practices *to resolve* frequent outage complaints that customers identify to customer service representatives and its executive offices are adequate. While there appears to be a process to communicate the problem to the other work units within the Company, it is less clear how solving the problem occurs after the problem has been communicated.

As a result of our inquiry, Staff and OCC recommend that the Commission require a third-party performance assessment of the Company's OMS and related systems to ensure that the system is adequately sized and sufficiently robust to accurately track and report customer outages. The review should include recommendations not only on the capacity of the system, but also internal management controls that should be instituted to ensure that the data is accurate and complete. *The stress-test review should be given top priority and modifications immediately implemented if deficiencies are identified because OMS system performance directly impacts the Company's ability to respond effectively to customer outages.*

As part of the third-party performance assessment of the Company's existing engineering and operational practices to solve problems, the third-party firm should evaluate whether the Company has sufficient procedures and resources in place to fix recurring outage problems once those have been identified and should recommend areas for improvement if deficiencies are identified.

The Company's practices concerning communications with critical care customers, and customers on life support systems may need improvement. While the Company has modified its practices concerning communications with critical care customers and customers on life support, we have not yet had an opportunity to thoroughly review the adequacy of those changes.

We recommend that the Company should make available for the Commission's, Staff's and OCC's review its modified practices concerning communications with critical care customers and customers on life support. If necessary, Staff and OCC should supplement this report on the issue and make additional recommendations after that review.

IV. How PSCo Dispatches and Communicates With Its Repair Crews

In the course of its investigation, we have not determined that the dispatch of repair crews and communications with these crews is a part of the problem with extended and frequent distribution system outages. Consequently, the engineering and management assessment first needs to cover this aspect and then results can be reviewed if deficiencies are identified.

V. Whether the Resources Dedicated to the Operation and Maintenance of the Distribution System Appear Adequate and Whether Adequate Capital Dollars Are Dedicated by PSCo to Maintain its Distribution Infrastructure and Refurbish this Infrastructure

A. Trends

One issue of concern is whether the distribution outages in 2002 and 2003 were a result of systematic decreases in maintenance and investment in PSCo's distribution system. To evaluate that issue, several maintenance and distribution data points over time, beginning with the last year that PSCo was a stand-alone Company (1995), and ending with the most recent data available (2002) were examined. The examined data points included annual expenditures for tree trimming, line transformer maintenance, overall distribution maintenance and annual investment in the distribution system.

We also examined the dividend payments from PSCo to its parent, Xcel Energy, the equity infusions from Xcel to PSCo and the earnings of PSCo. These data were then plotted against the number of PSCo customers each year, to see if any trends were apparent. The raw data are set forth in Chart I.

Chart I. Raw Data

	Raw Data								
Year	**Tree Trimming**	**Line Transformer Maintenance**	**Distribution Maintenance**	**Distribution Plant Additions**	**Customers**	**Dividends to Parent**	**Equity Infusions**	**Earnings**	**ROE (PBR)**
1995	$6,738,099	$82,696	$23,142,012	$95,163,951	1,092,820			$188,473,306	
1996	$6,439,915	$104,190	$22,918,847	$82,368,351	1,119,297			$214,897,836	
1997	$6,613,690	$176,487	$24,174,024	$152,280,863	1,143,035	$148,279,000	$273,300,000	$215,051,518	11.72%
1998	$6,383,959	$222,377	$24,715,447	$137,771,754	1,163,512	$180,430,000	$0	$231,246,627	11.50%
1999	$6,369,619	$164,922	$28,134,842	$130,914,962	1,194,900	$185,315,000	$109,372,000	$251,359,353	11.84%
2000	$5,700,004	$69,512	$21,842,266	$132,585,225	1,226,651	$180,786,000	$160,000,000	$264,472,091	12.45%
2001	$6,594,884	$251,674	$22,337,352	$179,278,262	1,252,537	$221,266,000	$15,249,000	$236,007,273	9.19%
2002	$5,167,410	$212,679	$21,208,563	$123,100,000	1,258,269	$230,867,000	$62,200,000	$240,850,436	9.17%
Average	$6,250,948	$160,567	$23,559,169	$129,182,921	1,181,378	$191,157,167	$103,353,500	$230,294,805	

In order to better compare the data from year to year, we then "normalized" the raw data, by expressing each year's data as a percentage of the average of the eight years' data (1995 through 2002). The normalized data are set forth in Chart II.

Chart II. Normalized Data

	Normalized Data							
Year	Tree Trimming	Line Transformers	Distribution Maintenance	Distribution Plant Additions	Customers	Dividends to Parent	Equity Infusion	Earnings
1995	107.79%	51.50%	98.23%	73.67%	92.50%			81.84%
1996	103.02%	64.89%	97.28%	63.76%	94.75%			93.31%
1997	105.80%	109.91%	102.61%	117.88%	96.75%	77.57%	264.43%	93.38%
1998	102.13%	138.49%	104.91%	106.65%	98.49%	94.39%	0.00%	100.41%
1999	101.90%	102.71%	119.42%	101.34%	101.14%	96.94%	105.82%	109.15%
2000	91.19%	43.29%	92.71%	102.63%	103.83%	94.57%	154.81%	114.84%
2001	105.50%	156.74%	94.81%	138.78%	106.02%	115.75%	14.75%	102.48%
2002	82.67%	132.45%	90.02%	95.29%	106.51%	120.77%	60.18%	104.58%

The raw data were also examined on a per customer basis. The per-customer data are set forth in Chart No. III. (The last three categories–dividends paid to the parent Company, equity infusion from the parent Company, and total PSCo earnings–were all divided by 5, so that they would fit into the approximate range of the other data considered.)

Chart III. Per Customer Data

	Per Customer Data						
Year	Tree Trimming	Line Transformers	Distribution Maintenance	Distribution Plant Additions	Dividends to Parent (/5)	Equity Infusion (/5)	Earnings (/5)
1995	$6.17	$0.08	$21.18	$87.08			$34.49
1996	$5.75	$0.09	$20.48	$73.59			$38.40
1997	$5.79	$0.15	$21.15	$133.23	$25.94	$47.82	$37.63
1998	$5.49	$0.19	$21.24	$118.41	$31.01	$0.00	$39.75
1999	$5.33	$0.14	$23.55	$109.56	$31.02	$18.31	$42.07
2000	$4.65	$0.06	$17.81	$108.09	$29.48	$26.09	$43.12
2001	$5.27	$0.20	$17.83	$143.13	$35.33	$2.43	$37.68
2002	$4.11	$0.17	$16.86	$97.83	$36.70	$9.89	$38.28

B. *Conclusions -- Charts I,II, & III*

Staff and the OCC believe that per customer data are the most useful, since we would expect maintenance and investment levels to generally track customer growth. The per customer data indicate that expenditures on tree trimming and overall distribution maintenance have declined from 1995 to 2002. The declines have not occurred every year. Line transformer expenses have varied without a clear trend. Distribution investment additions per customer are higher in 2002 than in 1995, but distribution plant investment additions per customer declined steadily since 1997 with the exception of 2001 when these investment additions were at their highest level.

PSCo's earnings during this period generally increased, although they have declined since 2000. However, PSCo's dividend payments to Xcel Energy have increased in all but one year since 1995. Equity infusions from Xcel to PSCo have declined steeply in the last two years.

When plotted, it appears that distribution maintenance expenses decreased slightly, while PSCo earnings increased slightly, during the period. Over the last two years it is somewhat disturbing to note that net payments from PSCo to Xcel Energy (dividends paid less equity infusions received) have increased dramatically, even while PSCo's earnings and maintenance expenses have decreased.

Figure II.

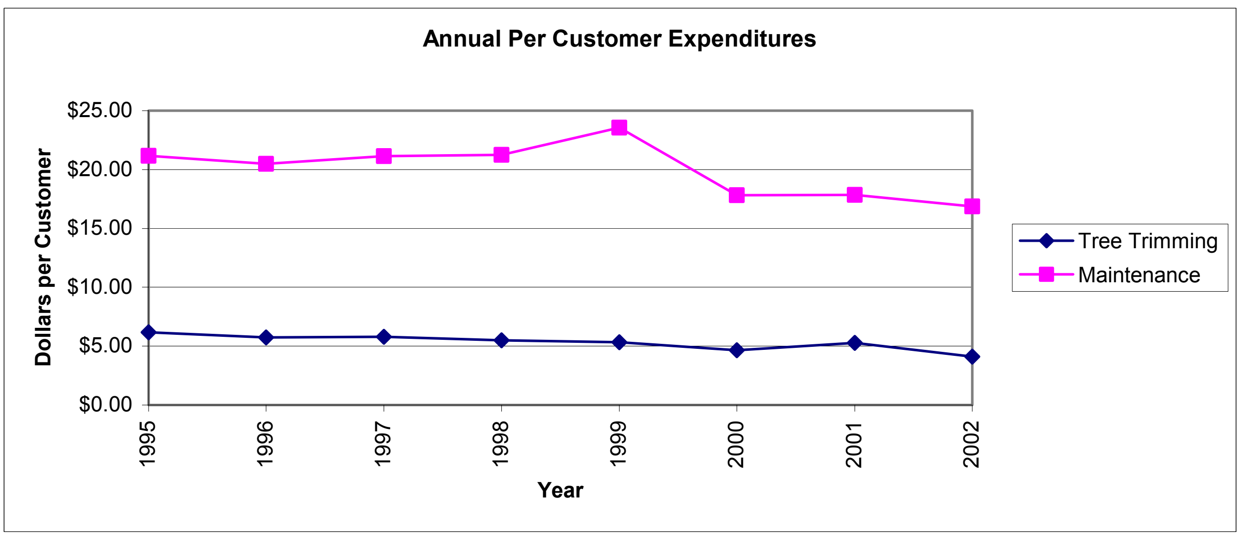
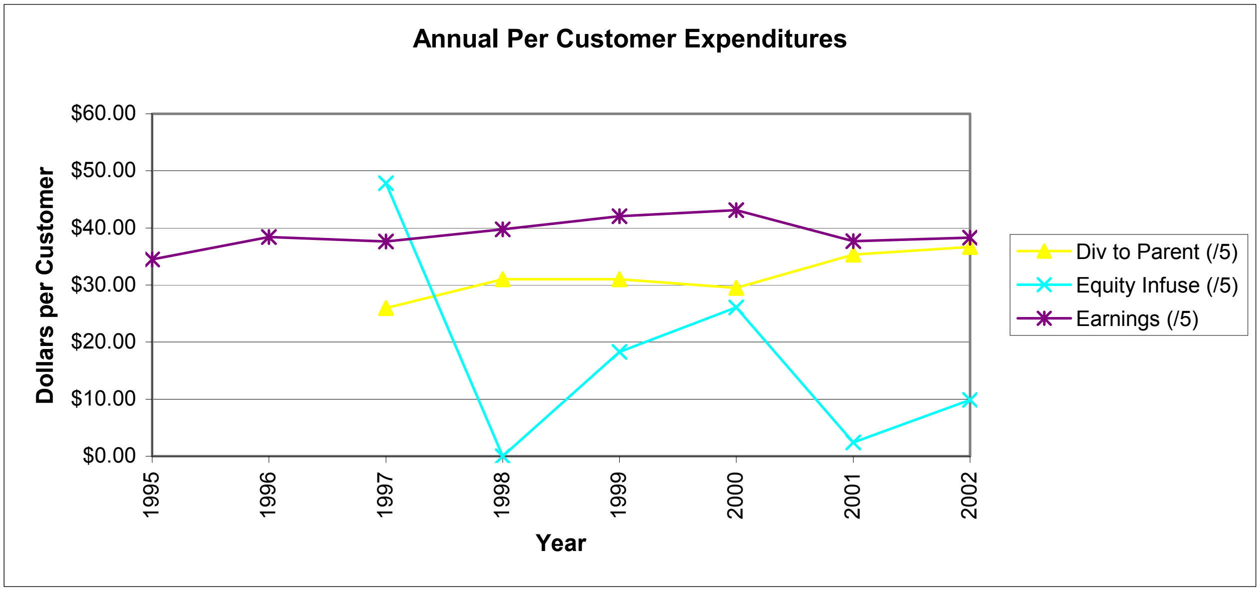


Figure III.



B. Conclusions – Expenditures

The trends show that Xcel Energy has drawn dividends from PSCo that were nearly equal to PSCo's profits during recent years. This, coupled with the dramatic decrease in equity infusions from Xcel, would have left less money available to PSCo to devote to maintenance of the distribution system. Even in years when PSCo's dividends paid and equity infusions were more balanced, there was still a trend toward increasing per-customer earnings, and decreasing per-customer expenses.

This information presents a macro view of PSCo's operations. The determination of whether the resources PSCo has dedicated to its Colorado operation is "enough" is difficult because it is difficult to ascertain the cause and effect of many of PSCo's actions. However, one traditional way of measuring "enough" is evaluating customer complaints. If that is used as an indicator, the answer is that customers do not believe sufficient resources are dedicated to solving frequent outages.

Overall Conclusions

A. General Recommendations

Staff and the OCC recommend that the Commission open an investigative proceeding to formally address the issues covered in this inquiry.

We believe that an investigative proceeding provides a public forum for the Company to address each of these issues. It also provides a forum for the Company to inform the Commission and the public of its progress towards solving the problems identified in this inquiry. Additionally, it provides a formal repository for third-party assessment reports and other documents critical to solving these problems as well as provides a forum where the Commission can issue orders, if necessary. Finally, it affords the Commission the maximum flexibility to address issues in the future- whether it is to close the proceeding because the issues are resolved, whether it is authorizing a “show-cause” proceeding, whether it is for the OCC to file a formal complaint with the Commission, or whether it is to initiate a rulemaking to clarify Commission performance expectations.

As stated previously, we recommend the Commission require a focused performance assessment by an independent third-party engineering and management firm to evaluate the current state of repair of the Company’s distribution system and its capability to serve current and foreseeable load. As parts of this assessment, the firm should evaluate whether the Company’s:

- Distribution system in its current condition meets industry standards and whether it is capable of serving current and foreseeable load;

- Preventive maintenance practices comport with best industry practices and should recommend areas for improvement if deficiencies are identified;

- Resources are sufficient to identify and fix the causes of frequent, chronic and recurring outage problems and recommend areas for improvement if deficiencies are identified;

- OMS and related systems are adequately sized and sufficiently robust to ensure accurate and timely prioritization, tracking, and reporting of customer outages;[86]

- Internal management controls are sufficient to ensure that outage information is timely recorded, accurate, complete, and reliable.

In a performance assessment, knowledgeable subject matter experts in the field of the assessment review existing systems and operations thereof, planned system changes, and provide advice on how to solve any deficiencies identified during the assessment. A performance assessment is generally focused toward a particular system or process.

B. Quality of Service Plan Modifications

Finally, as part of this investigation proceeding, we believe that modifications to the Company's QSP should be considered an open issue and recommend that the Commission encourage a review of existing Plan. The Company has already expressed to Staff and the OCC that they would like to revisit the "storm exclusion" process. As part of previous activities related to the QSP, Staff, OCC, and the Company already have committed to reevaluate the inclusion of secondary outages in the standards.

Staff and OCC recommend exploration of a number of QSP issues in addition to those identified in the preceding paragraph including, but not limited to:

- Evaluating whether the current incentives sufficiently encourage the right behavior;
- Adding QSP standards for frequent outages in distribution areas;
- Adding QSP standards for extended outages in distribution areas;
- Evaluating whether the regional definition of the Denver metro area is too large to identify problems in subparts of the area;

[86] This stress test should be given top priority and modifications immediately implemented if deficiencies are identified.

- Evaluating the merit of customer credits for extended outages similar to options already available for Minnesota NSP customers; and,
- Evaluating whether standardization of measures and incentives within the Company (Colorado vs. Minnesota vs. Texas) is appropriate.

If the Commission adopts our recommendation to open a proceeding, we recommend that this inquiry report be filed in that proceeding. Additionally, we recommend that the Company be required to present to the Commission its initial response to this inquiry during February of 2004. We recommend that the response be oral, with a formal written response submitted prior to the oral presentation. It may be beneficial to allow a panel-type presentation with all of the Company's representatives available simultaneously for questions by the Commission.

C. Alternative Procedural Options

As it evaluated the issues in this inquiry, Staff and OCC considered many options as recommended "next steps" for the Commission's consideration. These are discussed below, along with rationale as to why each option was not selected as our recommended best option. However, as always, the Commission may have more insight into how best to solve these complex issues.

Rulemaking Proceeding to Clarify Acceptable Minimum Performance Standards: This was not considered the best solution because the issues here are Company-specific, not industry-specific. It may be that additional guidance in the form of rules would assist the Company by specifically defining the Commission's expectation of adequate service. Other states, including Pennsylvania, Delaware, and California, have recently initiated such activities.

Management Audit of All Company Operations and Tracking Systems: This was not considered the best solution because it is a very expensive proposition and it is not focused. The management issues identified in this inquiry focus on two specific issues: the adequacy of the Company's engineering and operations practices for proactively maintaining its distribution network, and the adequacy of the Company's outage prioritization, tracking, and reporting requirements. It is our belief that a more focused assessment will drive a better evaluation of these specific areas.

Staff Show-Cause Proceeding: While such an action is possible under statute, this was not considered to be the best solution because the Company's resources would be spent defending its existing practices, rather than objectively evaluating whether change is necessary and then implementing the necessary changes. It would also require legal resources on behalf of Staff in addition to the subject-matter-expert resources already dedicated to the endeavor. This may be considered at a later date, if other efforts are not effective at resolving the problems.

OCC Complaint Proceeding: While such an action is possible under the statute, it was not considered to be the best solution because the Company's resources would be spent defending its existing practices, rather than objectively evaluating whether change is necessary and then implementing the necessary changes. It was also not considered to be the best solution because it would require legal resources on behalf of the OCC in addition to the subject-matter-expert resources already dedicated to the endeavor. This can be considered at a later date, if other efforts are not effective at resolving the problems.

Internal Company Audit of the Company's Engineering and Operational Practices and the Company's OMS and Related Systems (by Company's Internal Audit Group): This was not considered the best option because it is not clear that the Company's internal audit group has the expertise to identify best engineering and operational practices or to evaluate system capacity. Additionally, the management reviews performed to date appear to be "ad hoc" without formal written guidelines or criteria.

Requiring Company to Establish an Ombudsman Position Within the Company for Customers Affected by Repeat Outages: This was not selected because it is directing the Company on how to manage its business. Additionally, it appears that the Company's existing engineering and customer care organizations are already tasked with performing this function. Consequently, it may be a performance or resource issue, not a structural issue.

Staff Engineering Audit of the Company's Engineering and Operational Practices and the Company's OMS and Other Related Systems: This was not considered best option because Staff resource commitments would be substantial and resources are not available at this time without jeopardizing other critical work activities. Additionally, Staff does not currently have the expertise to evaluate whether the Company's OMS system is sufficiently sized.

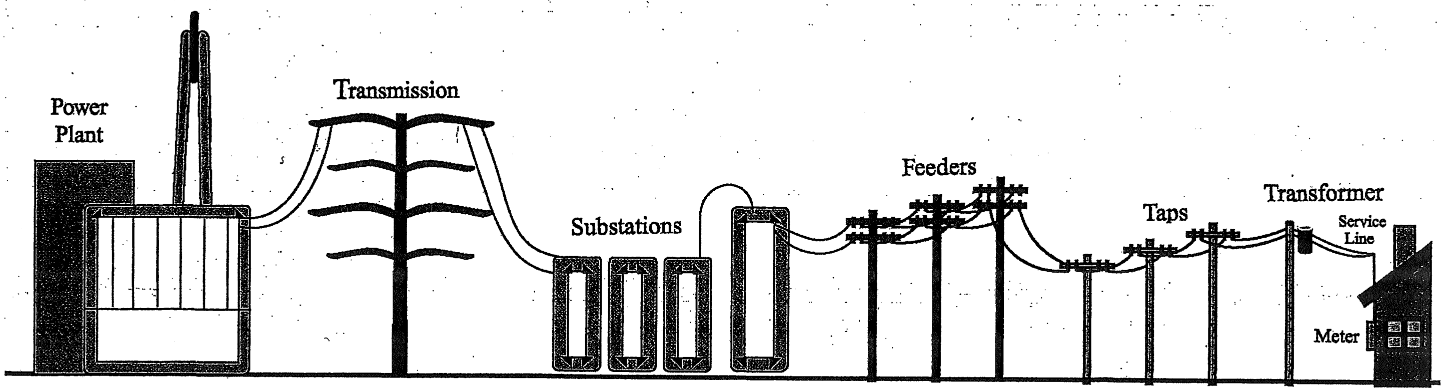
OCC Engineering Audit of the Company's Engineering and Operational Practices and the Company's OMS and Other Related Systems: This was not selected because the OCC does not have investigative audit powers by statute and does not have the resources to perform such a task. Additionally, OCC does not currently have the expertise to evaluate whether the Company's OMS system is sufficiently sized and does not currently have engineers on staff to evaluate the Company's engineering systems.

Additional Reporting Requirements: This was not selected because additional reporting does not solve the problem. While status and progress reports are likely to be required during the recommended investigation, these reporting requirements will be focused and hopefully will be temporary until the problem is resolved.

Don't Open a Proceeding: This was not selected because we believe sufficient issues have been raised to suggest that Commission intervention is necessary.

FIGURE 1

ELECTRIC DISTRIBUTION SYSTEM



1. Power generation

2. Transmission structure

3. Serves one or multiple communities

4. Serves 1,500 to 8,000 customers

5. Serves 40 to 400 customers

6. Serves 4 to 12 customers

How the Electric Distribution System Works

Power is carried to your home or business through an electric distribution system. Electricity is generated at a power plant and distributed by high-voltage transmission lines through various distribution systems until it reaches your home or business.

1. The **power plants** generate energy and distribute it to transmissions via high-voltage transmission lines.
2. The **transmission lines** are used to distribute power to strategically located area substations that may serve one or multiple communities.
3. The **substations** distribute power to major power lines called feeders. A distribution feeder may serve 1,500 to 8,000 customers.
4. From these **feeders**, Xcel Energy extends power lines called taps. Tap lines may serve 40 to 400 customers, including businesses and residential neighborhoods.
5. The **tap lines** distribute power to transformers that may serve 4 to12 customers.
6. The **transformers** are connected by service wires to your business or residence.

For outage information or restoration estimates, or to report an electrical disturbance or downed wires, please call **1-800-895-1999.**

Xcel Energy℠

P.O. Box 840
Denver, CO 80201
1-800-895-4999
www.xcelenergy.com

03-07-305 CSS#1067

ATTACHMENT 1

STATE OF COLORADO

PUBLIC UTILITIES COMMISSION

Gregory E. Sopkin, Chairman
Polly Page, Commissioner
Jim Dyer, Commissioner
Bruce N. Smith, Director

Department of Regulatory Agencies
Richard F. O'Donnell
Executive Director

Bill Owens
Governor

August 27, 2003

Mr. Fredric C. Stoffel
Vice President, Policy Development
Xcel Energy Inc.
1225 – 17th Street, Suite 1000
Denver, CO 80202

Dear Mr. Stoffel:

This letter concerns Public Service Company of Colorado's (PSCo or the Company) distribution system. In recent weeks, the Staff of the Public Utilities Commission (Staff) and the Office of Consumer Counsel (OCC) have become increasingly concerned about several issues related to the performance of PSCo's distribution system. During the recent summertime period of peak demand on the system, there were multiple and recurrent localized outages that appear to be related to undersized neighborhood transformers, underground cable failures, and customer outage software/systems' failures.

On July 29, 2003, we all attended a meeting in Centennial where customers related their unsatisfactory outages experiences with PSCo that occurred prior to the summer peak, including outages during the two large snowstorms. These outages and the Company's responses to the outages resulted in a significant increase in customer complaints at the Commission and at the OCC. Staff and the OCC are concerned about the condition and performance of PSCo's distribution system.

The recent meeting and the customer complaints have raised a number of issues that the Staff and the OCC believe should be examined. These include:

- The high rate of failure of neighborhood distribution transformers and whether PSCo is taking adequate measures to address the problems;
- Whether the Company's systems and engineering practices are adequate to timely identify inadequacies in the distribution infrastructure, particularly in older neighborhoods;
- How PSCo communicates with its customers during outages and whether customers are receiving accurate information;

1580 Logan Street, Office Level 2, Denver, Colorado 80203, 303-894-2000

www.dora.state.co.us/puc
Permit and Insurance (Outside Denver) 1-800-888-0170
TTY Users 711 (Relay Colorado)
Consumer Affairs 303-894-2070

Consumer Affairs (Outside Denver) 1-800-456-0858
Hearing Info 303-894-2025
Transportation Fax 303-894-2071
Fax 303-894-2065

- How PSCo dispatches and communicates with its repair crews;

- Whether the resources dedicated to the operation and maintenance of the system appear to be adequate; and,

- Whether adequate capital dollars are being dedicated by PSCo to maintain its distribution infrastructure and refurbish this infrastructure.

A related issue raised by customers, which is the subject of a Minnesota PUC investigation of Xcel Energy Inc., is how PSCo records the outages on its system and whether the outage information is reported accurately to the Commission.

We recognize that PSCo met with the Staff last year to discuss the transformer issue and that PSCo recently made a presentation to the Commissioners that discussed the transformer issue in some detail. Our understanding is that PSCo has a plan to address the transformer issue and that a number of transformers have been replaced. We greatly appreciate your cooperation and the information you have provided to date.

The issues consumers raised at the recent meeting in Centennial and elsewhere in the state lead us to seek additional information from the Company to determine whether further regulatory action is warranted. Staff and OCC will be seeking additional information jointly to address the issues we have identified in this letter. We are seeking PSCo's continued cooperation in responding to our information requests.

After we have compiled and analyzed this information, Staff and OCC will report to the Commission what we have found and make recommendations, if necessary, for further action.

Our expectation is to expedite the fact-finding phase of our joint effort so that we can report to the Commission no later than December 1, 2003.

Please feel free to contact us if you have any questions or concerns.

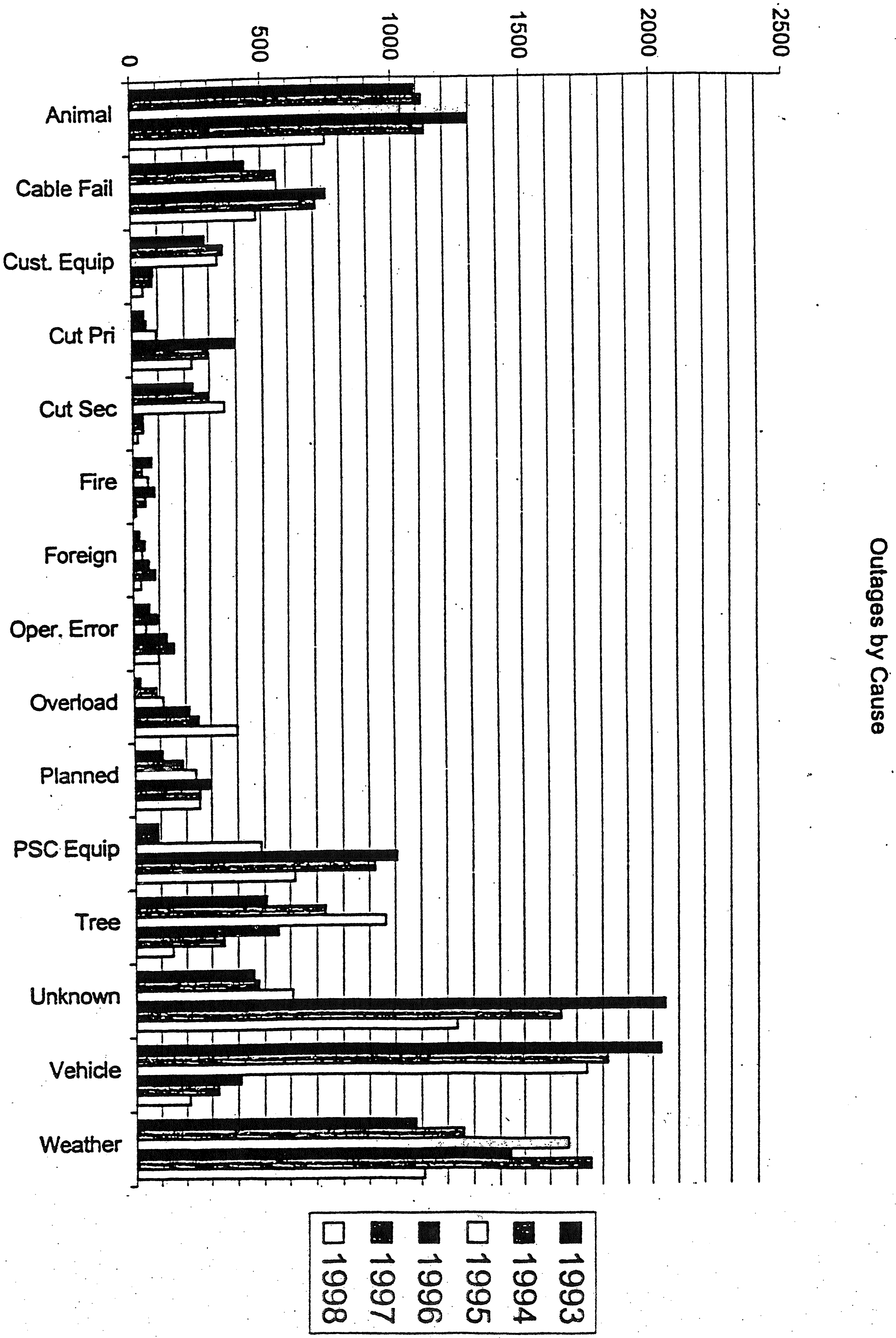
Very truly yours,

Bruce N. Smith, Director
Public Utilities Commission

Kenneth V. Reif, Director
Office of Consumer Counsel

ATTACHMENT 2

PSC OUTAGE
REPORT
TABLE DI-4
PAGE 1 OF 1



ATTACHMENT 3

2004 Reliability Action Plan for Colorado

2004 Colorado Reliability Management Program

Proactive Underground Cable Replacement - Replacement of 500 kcmil underground feeder main cable	$7,500,000
URD Accelerated Replacement - Replacement of URD cable after 2 interruptions	$750,000
Feeder Performance Improvement Program - Improvement of feeders operating at 3 times the average SAIFI or 4 times the average SAIDI	$1,575,000
Automated Switch Cabinets - Installation of automated devices to assist in prompt service restoration	$500,000
Remote Fault Indicators - Installation of fault indicators to assist in prompt service restoration	$500,000
Emergency Underground Cable Replacement - Emergency replacement of failed 500 kcmil feeder main cable	$2,500,000
Proactive Distribution Transformer Replacement - Replacement of distribution transformers	$1,000,000 *
Reduction in Devices Experiencing Multiple Interruptions - Reduction in devices experiencing 3 or more interruptions in the last year	$2,000,000 *
Vegetation Management - Continue 100% On-Cycle Trimming, "Hot Spot" trimming of isolated problems	$6,600,000
Total	$22,925,000

* Denotes use of $3,000,000 originally targeted for proactive transformer replacements

Other Reliability Actions

Add four Area Engineers (one in each of the 4 metro operating areas) to focus on Feeder Performance Improvement Program and reduction in devices experiencing multiple interruptions

Add Troublemen for faster restoration of service

Continue Rapid Transformer Replacement Program during the summer months which focuses on additional 1st Responders and replacement of distribution transformers

The $3,000,000 committed to proactive distribution transformer replacement program has been re-distributed into $1,000,000 for proactive transformer replacement and $2,000,000 for reducing distribution devices experiencing 3 or more interruptions in a year. The planned number of transformers proactively being replaced prior to July 2004 is approximately 600. The planned expenditures for proactive transformer replacement is being reduced from $3 Million to $1 Million because the model used for identifying replacement units continues to be developed. The continued development includes placing temperature labels on certain transformers to develop better correlation between "hot spot" temperatures in the transformers and transformer performance.

$2,000,000 will be re-directed to reducing the number of frequent interruptions caused by the same distribution devices. Distribution devices are classified as substation circuit breakers, distribution line reclosers, distribution line sectionalizers, distribution transformers and tap fuses. The devices experiencing three or more interruptions in the last year will be identified and given to Area Engineers to determine the reason for multiple interruptions and mitigate the problem. The target is to reduce the number of devices experiencing three or more interruptions by 30% in 2004.

ATTACHMENT 4

Public Service Company of Colorado	)	**Seventh Set of Data Requests**
	)	**of the Commission Staff**
Distribution System Reliability	)	**Dated September 18, 2003**

DATA REQUEST NO. Reliability7-7:
Please describe stress/volume testing of the performance of the "Power On" OMS system. Please include dates of the tests described. Please confirm that the latest tests were performed in February 2003. Please provide any written report or result of the stress/volume tests.

RESPONSE:
Stress testing of PowerOn 2.5.2 was conducted in January 2003. Please see Attachment Reliability7-7.A1 for the procedure that was used. The results of the testing were acceptable to the testing team and the user community and PowerOn 2.5.2 was implemented. The results of the tests were not retained.

Sponsor: Larry Carlson **Date:** 10/3/03

PowerOn 2.5.2 Volume Test Procedure

1) Model a big storm to the best of our abilities
   a) Send 200 calls
   b) Send 400 calls ten minutes later
   c) Send 600 calls ten minutes later
   d) Send 800 calls ten minutes later

2) Use the "shotgun" trouble call playback scripts to produce a large number of projects
   a) The shotgun approach will send calls from a large area.

3) Perform several feeder lockouts both within the storm area and outside of the storm area.

4) Restart/replay the trouble call playback scripts as the number of projects starts to drop significantly to keep the "volume" up high.

5) Perform several confirmed outages at reclosers and fuses outside of the storm area.

6) Perform several manually predicted outages outside of the storm area.

7) Set up 3 dispatcher workstations in test POD.

8) Have the trouble analyzer and MUP Reader each running on a dedicated workstation.

9) Run the volume test for several hours