BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1121

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In the Matter of	)
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OREGON ELECTRIC UTILITY	)
COMPANY, LLC, et al.,	)
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Application for Authorization to Acquire	)
Portland General Electric Company	)
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SURREBUTTAL TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

September 22, 2004

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OF OREGON

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In the Matter of OREGON ELECTRIC UTILITY COMPANY, LLC, et al., Application for Authorization to Acquire Portland General Electric Company	SURREBUTTAL TESTIMONY OF THE CITIZENS'UTILITY BOARD OF OREGON

Our names are Bob Jenks and Lowrey Brown, we previously submitted testimony for this docket on July 21, 2004. Our qualifications are in our opening testimony, CUB/101/Jenks-Brown/1 and CUB/102/Jenks-Brown/1 respectively.

I. Introduction

The Citizens' Utility Board continues to oppose this application based on our analysis of the potential harms to PGE and its customers. The proposed acquisition, as it currently stands, is long on risks and general assurances, and exceedingly short on protections and solid, tangible benefits.

In their rebuttal testimony, the Applicants spent a considerable amount of space explaining why our, Staff's, and other intervenors' concerns were either phantoms or unimportant. As a result, the Applicants did not make much progress in addressing the risks that most parties see as real and important. Despite the Texas Pacific Group's (TPG) blanket denials, we believe that the risks and shortcomings of this transactions, as stated primarily by Staff, ICNU, and CUB, are real. We did not find risks just to find risks, or to leverage a higher rate credit, as TPG suggests. On its face, this transaction includes a financial structure and a business plan that are new to the Commission, and which present genuine challenges under traditional regulation. Overcoming these unique problems will take unique solutions.

Our surrebuttal identifies, once again, the unique problems caused by this transaction, and explains why the Applicants' denials of the risk lack credibility and prevent a clear path toward an acceptable outcome. We offer conditions, including a unique proposal that appropriately considers the endgame in this necessarily short-term arrangement, which turn this filing that is devoid of merit into an approach worth pursuing. In his testimony, Jim Dittmer also responds to TPG's denial of risk and addresses a number of issues including the double leveraged capital structure and the income tax issue.

II. Regulation Not Designed For Aggressive Cost-Cutting

The regulatory structure, as it currently exists, is far better at denying recovery of expenditures as imprudent, than it is at encouraging the appropriate level of expenditures. To counter a long-term owner's incentive to gold-plate or spend freely, this has worked reasonably well. It was neither envisioned nor intended, however, to counter the incentives of a short-term owner.

A. Texas Pacific Expects To Cut Costs.

In our opening testimony, we explained that the natural incentives for a short-term owner are to make significant cost cuts and simultaneously make as little capital investment as possible. CUB/100/Jenks-Brown/4 12. We documented that TPG expects to cut costs. Staff and ICNU identified similar expectations.

Most of TPG's projected scenarios included cost reductions. In his rebuttal testimony, Mr. Davis states that, "most of the recommendations…were the result of a number of 'benchmarking exercises'," OE/100/Davis/15, and not the "basis of an operational plan." OE/100/Davis/16. CUB Confidential Exhibit 301 is a page from an internal presentation which represents TPG's approach to cost-cutting. While we concede that this is not an "operational plan," we do believe that the due diligence documents tell us something about TPG's expectations. In addition, Mr. Davis states that TPG's consultants compared PGE to other utilities. CUB Confidential Exhibit 302 contains some of the information showing the basis of those comparisons, and it too displays TPG's thinking.

It is not just TPG's due diligence documents that lead us to believe it is expecting to cut costs significantly. It is consistent with Texas Pacific's management style at other companies it has purchased.

In Mr. Davis' rebuttal testimony, responding to our concerns about TPG cost-cutting and the incentive to avoid capital investments, he cites five examples of TPG companies where TPG made capital investments during its ownership period: Continental Airlines, Seagate Technology, J.Crew, Petco Animal Supplies, and MERC Electronic Materials. OE/100/Davis/12-13. A review of the TPG acquisitions that Mr. Davis holds out as examples of TPG's commitment to capital investment only serves to confirm CUB's concern that cost-cutting is an expected and important part of TPG's business plan.

TPG cites Continental Airlines as a big success. From their perspective it may have been, but that success began by eliminating 4,000 jobs, 11% of the workforce, and cutting 18% of the company's flights. Most of the flights out of Denver and throughout the Western United States were cut. CUB Exhibits 303 and 304.

CUB Exhibit 305 shows that employment at Seagate declined dramatically after TPG acquired it. In 2000, when it was purchased by TPG, the company had 60,000 employees. Three years later, Seagate had a workforce of only 43,000, a reduction of 28%.

MERC had 6,600 full-time workers and 370 temporary workers on December 31, 2000, just before TPG's acquisition. Two years later, after TPG's acquisition, the company had reduced its workforce to 4,600 full-time and 100 temporary workers, a reduction of 33%. CUB Exhibit 306.

TPG acquired J. Crew in 1997. CUB Exhibit 307 shows that on January 31, 1998, J.Crew had 6,200 associates, 4,200 of whom were full-time employees. One year later, on January 31, 1999, J.Crew had 5,400 associates, 2,600 of whom were full-time. The total number of employees may only have decreased by 13%, but the number of full-time employees dropped 38%.

As for PETCO, TPG was unable to provide us with a 10-K filing for the year after it acquired the company. They believe a 10-K was never filed since PETCO was not publicly traded. We have no independent or publicly available data with which we can determine TPG cost cuts.

These examples of cost-cutting and employee reductions were undertaken as part of a strategy that assumed an eventual resale of each of the companies. Clearly, our concern about strategic cost-cutting, while largely dismissed by the applicants, is a serious one.

B. Regulatory Process Not Well Designed For Aggressive Cost-Cutting

TPG dismisses our concerns as unfounded, and thereby justifying a paltry rate credit, because their due diligence work was never intended to guide their actual management strategy. TPG argues that, even if they had intended to cut costs, we should feel safe. Our primary protection, the Applicants assure us, is the due diligence of the next PGE buyer. In order for the Applicants to make a profit in their eventual sale, they must invest in and maintain PGE. In addition to this bulwark, we are assured that the regulatory authority of the Commission will protect us.

1. A Buyer’s Due Diligence Will Not Protect Customers

In regard to the protection provided by the watchful eye of the next buyer, TPG states that it will not shirk its investment responsibilities, because any potential buyer of PGE would conduct due diligence and would find any underinvestment. OE/100/Davis/9. Yet, in explaining why the cost-cutting in TPG’s own due diligence was not intended for an operating strategy, TPG explains at length why due diligence is an imperfect tool at best. Mr. Davis says that due diligence findings, “are typically limited by the level and quality of information to which the buyer has access,” and that due diligence has, “inherent limitations.” OE/100/Davis/15. He goes on to say that TPG’s own due diligence was, “limited by the fact that they were conducted from an external vantage point and with only the limited information provided to TPG and its consultants.” OE/100/Davis/16.

We agree with TPG about the limitations and weaknesses of due diligence, and we will not rely on the threat of a potential buyer’s due diligence process to protect customers. We are not willing to gamble that we are protected by the future analysis of someone who is not identified, whose motives in purchasing PGE are not known, whose due diligence is of uncertain quality, and who may not enter the picture for several years. If we must rely on TPG's profit motive to ensure that PGE is well managed, then we should reject this deal because we are admitting that our regulatory structure is not up to the task of protecting us from a temporary owner.

In addition, history tells us that a new buyer may still pay a premium for a utility that has under invested in its network, created serious reliability problems, and developed a hostile relationship with regulators. Later in this testimony we cite problems associated with US West's aggressive cost-cutting. Those problems were not unique to Oregon, but were consistent throughout US West's 14-state service territory. On May 3, 1999 US West stock price closed at $53.875 per share. CUB Exhibit 308 shows that less than two months later, after a bidding war with Global Crossing, Qwest won the right to purchase US West for $69.00 per share, a premium of 28%.

2. Aggressive Cost-Cutting, Underinvestment & The Regulated Utility

We continue to have concerns that cost-cutting could have negative implications for customers, and that those implications may not show up during TPG's control of PGE. The answer that we should simply trust TPG not to cut costs to a level that could impact customers is not reassuring. TPG does not have experience in an economically regulated monopoly such as this. At Continental Airlines, they could cut 18% of flights, and while this reduced the options for customers in the cities that were experiencing cuts, sometimes severely, those customers presumably had alternatives. When Burger King closed the restaurant in downtown Portland, its customers could go to any number of other restaurants within a few blocks.

Cutting costs at an electric utility, however, with its mandated obligation to serve, is not so simple. TPG cannot decide that some of the rural areas of Marion, Polk, Clackamas, Yamhill, or Washington Counties are too expensive to serve, even if serving those areas costs more than PGE collects in rates from those areas. Similarly, TPG simply cannot cut 30% of PGE's linemen and expect service not to deteriorate.

Even if we take them at their word, there is no guarantee that TPG's cost-cutting will not impact customers negatively. Our protection is our system of regulation, so the real question is whether our regulatory system is set up to oversee a short-term owner whose incentive to cut costs can lead to underinvestment in the system.

The argument from the Applicants and their witness is that the current regulatory framework will protect us.

> [T]he Commission has a vast array of powers to deal with events as they arise and to prevent certain negative events from happening. This is the role of any public utility commission, and I expect this Commission to continue to exert its authority.
>
> - OE/400/McDermott/12

> The Commission retains authority over PGE's finances, operations, and investment. Specifically, the Commission retains regulatory authority to monitor PGE to determine if investment, financing, or other policies of the company would be detrimental to the provision of safe, reliable, and reasonably priced service.
>
> - OE/400/McDermott/13

> [T]he Commission has the ability to investigate the operations of PGE and order the company to rectify any deficiencies in practice or investment that it believes are endangering the long-term safety and/or reliability of the company's services.
>
> - OE/400/McDermott/17

> The Commission's ability to regulate PGE applies to PGE regardless of ownership structure. Accordingly, any alleged short-timer's incentive would be more than off-set by the rules and regulations in place in Oregon.
>
> - OE/400/McDermott/21

> All of the risks that do exist are mitigated by regulatory protections.
>
> - OE/400/McDermott/12

> I can state from experience that regulators do not, as they should not, take these requirements lightly. It is their obligation to administer the law as it is written and to make sure that utilities are providing for long-term investment to maintain and expand the system.
>
> - OE/400/McDermott/17

> PGE is a heavily regulated utility carrying out its operations under the scrutiny of effective regulators. As Dr. McDermott explains in his testimony, the Commission has broad statutory authority with full investigatory powers and power to regulate the rates, terms, and conditions of PGE's electric services. Under this statutory scheme, the Commission can review PGE's operations and spending and question PGE's management about any concerns their review may raise.
>
> - OE/100/Davis/18

> We certainly believe that this Commission has the authority, ability, and will to oversee PGE and ensure that the company is being responsibly operated and maintained. We do not accept the parties' suggestions to the contrary.
>
> - OE/100/Davis/20

In order to understand how these powers of the Commission can be used to protect, or not protect, customers when a utility in engaged in aggressive cost-cutting, we will first start by examining two examples of utilities that failed to invest in the system and implemented cost-cutting on a scale that undermined the provision of reliable service, creating a significant harm to customers. One is an example that we in Oregon are familiar with and the other is an example from Illinois that TPG witness, Dr. McDermott, is familiar with.

a. US West

US West did not adequately invest in its Oregon network for many years. In the early 1990's Oregon customers of US West began to experience problems that were caused by this lack of investment. Throughout the decade, we experienced one problem after another. As one set of problems began to improve another would develop, only to be followed by yet another one.

- Early in the 1990's US West began to experience problems with their lines in Portland and other urban areas. Their lines were decades-old, lead-wrapped copper wires that were cracked. After a storm, with a little wind and rain, water would get into the cracks and short out lines. Identifying where these shorts were, drying out the lines, and repairing the cracks was not an easy process. Once the rain arrived in the fall and continuing through spring the company was constantly behind in repairing customers' lines, and customers often had to wait days at a time for their phone service to be restored.

- As the decade wore on, the company simply did not have enough line personnel and capacity to meet the demands placed on its aged phone system. During this period there was a constant problem with held orders. People who requested new service from the company were unable to receive it in a timely fashion. Many individuals were waiting four to six weeks for a dial tone at their home or business. Excerpts from, Is Life Better Here?, a consumer survey of US West Local Telephone Service Quality is CUB Exhibit 309.

- In October of 1998, only 16 of 77 US West wire centers met the OPUC standard that allows only 2 trouble reports per 100 lines per wire center per month in any 12-month period. CUB Exhibit 309.

- By the end of the decade things had finally begun to improve in the major urban areas of the state, but new problems were occurring in smaller communities such as Roseburg, Oakridge, Klamath Falls, and Grants Pass. In these communities US West had not installed digital switches, which had been approved by the Commission in their construction budget, but which the company did not actually buy or install. Many customers were finding that all lines were busy, and they were unable to make calls. OPUC press releases from 1999 are CUB Exhibit 310.

All of these problems had a consistent root cause. The company failed to make the necessary investment in its system for many years, and the company did not have enough employees in the field to deal with the problems that surfaced with their old network.

b. Commonwealth Edison

Commonwealth Edison is an electric utility in Illinois. Throughout the 1990s it did not adequately invest in its distribution system. By 1998 and 1999, customers began experiencing a series of outages due to the company's poor investment and management of its system. As a result of these outages, the Illinois Commerce Commission (ICC) began investigating the problem.

- According to a news release from the ICC, a consultant hired by the ICC to investigate the 1999 outages concluded that the "root cause of the outages was cable failure, due to a heat-induced breakdown of insulation brought on by repeated cable overloading…The Vantage report cited poor maintenance of equipment as a contributing factor in the equipment." CUB Exhibit 311

- According to a later news release from the ICC, Liberty Consulting Group, which was hired by the ICC to investigate the 1999 outages, concluded that the "electrical system failed in summer 1999 because the company had not spent nearly enough money on maintenance and necessary system improvements in prior years." CUB Exhibit 312

- CUB Exhibit 313 is the Executive Summary of the Liberty report. According to the report, during the 1990's Commonwealth Edison's "goals and objectives were dominated by cost control." Commonwealth Edison's "transmission and distribution capital and operations and maintenance expenditures declined in the mid-1990's… These declines were the result of ComEd's conscious and concerted efforts to reduce costs…The load on many of ComEd's feeders was more than 110 percent of capacity…In the summer of 1999, ComEd had a backlog of 79,000 maintenance items." The full report can be viewed at: http://www.icc.state.il.us/ec/library.aspx?key=electricity. Its Category is "ComEd System Investigations" and its Post Date is 4/16/2001.

- According to a 7-19-00 news release from the ICC, the Liberty Consulting Group, "found that, among other shortcomings, the utility's tree trimming programs were inadequate, poorly planned and understaffed. The report states that many of the interruptions of electric service experienced by Commonwealth Edison's customers were caused by trees contacting the utility's distribution facilities and that funding for tree trimming was inadequate…Liberty also concluded that Commonwealth Edison had failed to adopt a recommendation for increased tree trimming from a 1992 audit conducted by Resource Management International for the ICC." CUB Exhibit 314.

- In its annual report to Governor George Ryan and the Joint Committee on Legislative Support Service, the ICC cited the Liberty Consulting Group and stated that Commonwealth Edison's "electrical system failed in summer 1999 because the company had not spent nearly enough money on maintenance and necessary system improvements in prior years" and that it often failed to meet "its own standards or follow its own procedures because it failed to budget enough money for necessary capital improvements and maintenance." Excerpts from that report are CUB Exhibit 315.

- CUB Exhibit 316 shows that even Commonwealth Edison's own report on the outages, Blueprint For Change, showed serious problems. It found that "almost a third of ComEd's large substations (approximately 73) operate above capacity at times of peak demand" and that "almost one fifth of ComEd's small substations and feeders (approximately 880) operate above capacity at times of peak demand."
- According to the utility's Blueprint for Change report, "ComEd recognizes that fundamental change in T&D performance requires an across-the-board effort" including "a commitment of bottom-line dollars to the largest, most accelerated capital improvement program in the history of the company."

It is, of course, ironic that Dr. McDermott is the most adamant TPG witness arguing that regulation will protect us against underinvestment, because Dr. McDermott was a member of the Illinois Commerce Commission precisely during the period when Commonwealth Edison failed to make the necessary infrastructure investments, which led directly to significant interruptions of service.

3. Can Regulation Protect Us From Aggressive Cost-Cutting & Underinvestment?

Texas Pacific's witness would have us believe that we need not worry about the consequences of aggressive cost-cutting, because we have a system of regulation that can, and will, protect us. CUB Exhibit 317 and Exhibit 318 are answers to our data requests where we attempted to get the applicants and their witness, Dr. McDermott, to identify what authority the Commission has to ensure that a utility is making the necessary investments. The answers list the following powers of the Commission:

- Ratemaking
- Ring-fencing
- Investigation Ability
- Integrated Resource Planning
- Merger Conditions (other than ring-fencing)

We examine these powers in order.

a. Ratemaking

While several witnesses state this, we will cite Dr. McDermott's testimony, since it is representative of TPG's position, and, as an Illinois regulator, he ought to be familiar with the ability of regulators to prevent cost-cutting.

> First, I note that Mr. Davis explains why PGE's owner would be foolish not to attend to the appropriate long-term needs of the company based on its own financial motives. In addition, if for no other reason, PGE's owners will be motivated to maintain the utility's long-term health to maintain a positive relationship with the Commission. Remember that a utility derives its income from the level of rates that are allowed by the Commission. The Commission has the ability to "disallow" costs that are imprudently spent and monitor and investigate a utility that appears to be imprudently budgeting for the long-term viability. No utility wants to have a regulatory body constantly investigating its operation and maintenance practices and policies, and, therefore, it has an incentive to carefully plan for the future.
>
> \- OE/400/McDermott/18

Yet Dr. McDermott's personal experience suggests a very different story. He was on the Illinois Commission from 1992-1998. OE/Exhibit 4/McDermott/1. As we have seen above, after he left the ICC, serious problems developed with Commonwealth Edison that led the next Illinois Commission to investigate its operation and maintenance practices and policies. For that investigation, the ICC hired outside consultants, the Liberty Consulting Group, whose report concluded that, "the Commonwealth Edison's electrical system failed in summer 1999 because the company had not spent nearly enough money on maintenance and necessary system improvements in prior years." CUB Exhibit 315. Those "prior years" were the years when Dr. McDermott was a Commissioner, and, with all the regulatory tools at his disposal, he was somehow unable to prevent the cost-cutting from harming the utility and its fundamental reliability.

CUB Exhibit 319 is Dr. McDermott's answer to our data request concerning Commonwealth Edison. The answer states that, "Dr. McDermott has not undertaken a specific analysis of Commonwealth Edison's investments in its distribution system, or what measures the ICC took over a ten-year period of time to monitor such investments." He was a member of the Commission during much of this ten-year period of time and should not have to undertake an analysis to determine what measures the ICC took or didn't take; he was there at the time.

In addition, Dr. McDermott dismisses the Liberty Consultants report by noting that, "[t]he consultants, not the ICC, made the statement," that Commonwealth Edison had not invested enough in its distribution system and that this contributed to the outage. CUB Exhibit 319. The ICC hired the consultants. The ICC decided which conclusion of the consultants to quote in a series of news releases. The ICC repeated the conclusions of the consultants in the ICC's annual report to the Governor and the Legislature. If the conclusion that Commonwealth Edison under funded its capital investment and O&M was not what the ICC believed to be true, then it was being irresponsible in amplifying this conclusion. While Dr. McDermott knows these people better than we do, we seriously doubt that they were acting irresponsibly.

Dr. McDermott also cites a later rate case, where the ICC declined to disallow some of the investment that was being made belatedly in the distribution and transmission system as imprudent, even though the company had failed to make the investment earlier. Commonwealth Edison's lead witness in this stage of the case successfully argued against a finding of imprudence, because, the witness argued, hindsight is inappropriate in a prudence review. This shows why a Commission's ability to find a cost imprudent is not a very good tool to use to ensure that investment is being made consistently over time.

Oh, by the way, who was that Commonwealth Edison witness who convinced the ICC it should not, or could not, use its "ability to 'disallow' costs that are imprudently spent and monitor and investigate a utility that appears to be imprudently budgeting for the long-term viability?" OE/400/McDermott/18. None other than former Commissioner McDermott, the TPG witness who wrote the above to convince us to trust regulation completely.

In this Commonwealth Edison case, some intervenors did try to challenge the company's costs in a 2001 rate case arguing that the company was imprudent by not making the investments earlier. CUB Exhibit 320 is Dr. McDermott's testimony on that issue in the rate case. In that testimony he makes the following arguments:

> 20/20 hindsight is inappropriate. The inquiry should be whether the decisions at the time they were made were reasonable under circumstances, not based on hindsight. This is, of course, a difficult trap to avoid because rate cases using historical test years are inherently retrospective in that the investments have usually already been made (or will be made during the test year) and the utility is seeking inclusion of those costs in the revenue requirement. This makes it very difficult for a review to avoid being influenced by hindsight as the after-the-fact results are well known. "Results-oriented" analysis are simply impermissible.
>
> \- CUB Exhibit 320

In other words, when the Commission is looking at the prudence of a current huge investment in infrastructure, it can't look at the underlying cause for the need, i.e. the massive decade-long underinvestment, it can only look at the fact that it is currently prudent to invest huge amounts to fix the crumbling utility.

We agree with Dr. McDermott that 20/20 hindsight is inappropriate for a prudence review, yet this is one of the reasons that prudence is a terrible tool for preventing long-term underinvestment. Unlike a utility's investment in new plant or equipment which is implemented with a rate case that reviews it, cost-cutting happens between rate cases, because that is the only time the benefits of the cost-cutting will accrue to the shareholders. The cost-cutting will only become a rate case issue in a future rate case, where the consequences of the cost-cutting have been observed. It is only with hindsight that we have the opportunity to review cost-cutting practices of a utility, but Dr. McDermott would then dismiss the prudence review because it is based on hindsight.

> …Liberty simply cites to self-critical statements that ComEd made in a report drafted after the 1999 outages, "the Blueprint for Change." That document is predominantly a hindsight analysis that ComEd prepared in the wake of the 1999 outages to be used as a tool to make improvements. It is inappropriate for Liberty to cite to it as a substitute for Liberty's own factual analysis of prudence.
>
> - CUB Exhibit 320

A utility fails to make an investment in infrastructure. Reliability crumbles. Consumers are outraged. The utility, itself, admits that its infrastructure is in terrible shape, needs massive amounts of new investments, that the utility needs "fundamental change." The utility commits itself to "new people, new programs, new perspectives, new proposals – and most importantly – new performance." CUB Exhibit 316. Yet, none of this can be used in a prudence review of historic investment, because it is hindsight. But the company did under invest and took cost-cutting too far. Service suffered. Customers suffered.

In that case, Dr. McDermott was paid to argue that the Commission cannot correct for continual underinvestment, even after the underinvestment has taken it toll on customers and the utility system. In this case, Dr. McDermott is paid to argue that we should trust regulation to protect customers from underinvestment and system deterioration. Dr. McDermott seems to be willing to argue both sides of the same issue and therefore his testimony is of no value and should be ignored.

Closer to home, in the US West example, the "rate-making power" of the Commission never materialized. Many of us were concerned that the company was not making the necessary investments in its infrastructure. We were pressuring the company to make additional investment. When they did finally start making the investment it did not make sense to then argue that the investments should be disallowed. Disallowing cost recovery discourages the very investments we were calling for, and places the customers in a no-win situation. Yet, without an actual on-going power to oversee investments, the customer can lose first from poor service quality and then from the rate increase that comes from catching up in investments, potentially at a higher cost than if the investments had been made on a consistent basis.

If the basic function of the Commission, the rate setting responsibility and the ability to disallow costs that are imprudent, offers us no protection then we must look at the other regulatory tools that TPG cites.

b. Ring-Fencing

The ring-fencing conditions arguably protect the utility from getting in such poor financial state that it is forced to cut back on O&M and to stop making investments, but offers us little protection from an owner who believes strategic cost-cutting is a fundamental part of its business plan.

c. Investigation

In an answer to a CUB data request, the Applicants describe the protection provided by the Commission's investigative ability this way:

> The Commission has the ability to investigate PGE's budgets for capital expenditure and operation expenses. This provides an incentive to the company to prudently invest.
>
> - CUB Exhibit 317

In answer to another data request, the Applicants add a little detail. "The Commission has the following authority:"

> To monitor and investigate PGE's operations and order PGE to rectify any deficiencies in practice or investment that it believes are endangering the long-term safety and/or reliability of the company's services.
>
> - CUB Exhibit 318

There are several problems with relying on the power of the Commission to investigate without further conditions. First, the Commission has a limited budget and staff. While the Commission may investigate PGE's operations and its investments, it may not have the resources to conduct the necessary review of investments and O&M to ensure that cost-cutting is not harming customers. Secondly, we are not convinced that the Commission has the power to order PGE to "rectify deficiencies" in investment, if this is read to mean that the Commission can order the utility to make certain necessary investments. Applicant witness Jim Piro seems to agree with us. According to Mr. Piro, "the Commission cannot, generally speaking, force us to spend money." PGE/100/Piro/9.

This is consistent with our experience. CUB Exhibit 321 is a news release from the PUC trying to get US West to commit to replacing analog switches with digital switches. The old analog switches were causing serious problems for phone customers in Roseburg. In order to get US West to act, the Commission had to ask and try to embarrass the company in the press; it did not order the company to replace the switches. If the Commission had the ability to order the company to install the switches, there is no doubt that they would have done so.

As it stands, the ability of the Commission to investigate utility operations and investment is not sufficient to protect against aggressive cost-cutting. However, we do believe this can be significantly remedied by requiring PGE shareholders to pay for the cost of any necessary audits of their operations and investment that the Commission determines to be necessary, and by the applicants agreeing that they will comply with any PUC orders that require it to take action "to rectify any deficiencies in practice or investment."

d. Integrated Resource Plans

The Applicants state that the Integrated Resource Plan offers customers protection because "PGE incurs substantial risk if it fails to acquire resources in accordance with an acknowledged plan." CUB Exhibit 317. There are several problems with relying on this. First, it only applies to power supply. Second, utilities often do not acquire resources in accordance with an acknowledged plan. The IRP process is long and produces a multi-year action plan. Circumstances change during the IRP process, and, after the IRP process but before resources are acquired, a utility must have the ability to adapt to changing circumstances. To blindly follow an approved IRP may well lead to imprudent actions. Third, there is a history of utilities failing to acquire cost-effective conservation resources and renewable resources that are part of an approved IRP. We know of no penalties that the Commission has ever levied on a company for such a failure.

e. Other Merger Conditions (Other Than Ring-Fencing)

We are not sure which conditions this refers to, but we have already suggested two. The Commission should have the ability to hire an auditor, at the applicants' expense, to review their investment and operations, and the applicants should commit to comply with any orders that come out of such an investigation.

III. The Tax Loophole

There has already been considerable discussion of the tax loophole which allows Oregon Electric Utility Company (Oregon Electric) to collect millions of dollars in taxes from PGE customers which are not passed on to the state or federal governments. The Applicants argue that to address this issue, one must address the fundamental regulatory principal of treating PGE as a stand-alone company for ratemaking purposes. This is not the case. This issue relates, not to the ratemaking treatment of PGE, but to the relationship between PGE and the specific tax deductions in question. PGE customers pay the interest and share the risk, and are, therefore, entitled to the tax deductions. This is not an issue of whether to regulate PGE at a stand-alone or consolidated level, as the costs and risks of this debt will be borne by PGE customers regardless, CUB/400/Dittmer/5, but whether regulators should acknowledge those things at the parent company that directly impact PGE.

A. Oregon Electric Tax Deduction Directly Related To PGE

In their rebuttal, Mssrs. Tinker, Murray, and Hager included excerpts from Accounting for Public Utilities which had originally been included in a Staff Report in UM 1074. Those excerpts state:

> The basic theory is that the regulated costs should not be affected by the results from nonregulated operations....Thus, if ratepayers are held responsible for costs, they are entitled to the tax benefits associated with the costs....When these risks are not borne by the ratepayers it is unfair to reduced [sic] the utility's cost in determining the rates to be charged for utility services.
>
> - PGE/205/Tinker-Murray-Hager/7

Certainly, we agree. Where we do not agree, however, is on the applicability of these excerpts to the tax issue at hand. In fact, these excerpts support our position that customers are entitled to the tax deductions at Oregon Electric because that debt is anything but unrelated to PGE, and PGE ratepayers do indeed bear both risks and costs from that debt.

The debt at Oregon Electric was taken on for the specific purpose of purchasing PGE, it is secured primarily with PGE stock, OE/Exhibit 19/12, as Mr. Dittmer points out, customers will be paying the interest on the debt, CUB/400/Dittmer/5, and as we, Mr. Dittmer, and other intervenors have argued, customers share the risk of the double leveraged structure created by Oregon Electric's considerable debt. CUB/100/Jenks-Brown/13, CUB/200/Dittmer/12-13 & 25-38, Staff/200/Morgan/28-30, ICNU/200/Antonuk-Vickroy/16-28, CUB/400/Dittmer/3.

B. Capture Interest Deduction Not True-Up Taxes

Mssrs. Tinker, Murray, and Hager, in their rebuttal, make a pertinent distinction between a general tax true-up, which would violate IRS normalization requirements, and capturing the interest deduction from Oregon Electric debt. PGE/200/Tinker-Murray-Hager/12. We agree that affiliate and parent company tax liabilities and deductions from unrelated, non-utility business should not be included when estimating the tax liability PGE customers will be responsible for. What CUB recommends, given the association between PGE and the debt at Oregon Electric, is an accounting for those specific deductions when calculating PGE's revenue requirement.

C. Recognizing PGE-Connected Tax Deductions Is Not Inconsistent

PGE's rebuttal suggests it would be inconsistent to recognize the tax deductions at Oregon Electric without also looking at every possible loss, gain, deduction, and liability, no matter how far removed from PGE's regulated operations.

> [T]o consider the tax effects of Oregon Electric's debt service in setting PGE's rates, the Commission would have to base PGE's rates on Oregon Electric in its entirety, including, among other things, Oregon Electric's weighted after-tax cost of capital, interest expense, operating expense, and all of its other liabilities and obligations. Anything less would be inconsistent.
>
> \- PGE/200/Tinker-Murray-Hager/15

This implies that there is an impenetrable wall between PGE and its parent company, which has not been breached, and should it be so, regulation would be turned on its head. There is no such impenetrable wall, as we well know from the risks of double leverage, the concerns of rating agencies, and our own experience. With every ownership change, the applicant has agreed to a number of conditions designed to shield PGE from its parent company, but these are only protections, not absolutes. We are certainly not advocating any change in the practice of treating PGE as a stand-alone company for ratemaking purposes, we are advocating only for recognition of the imperfections in that system.

The costs and the risks of Oregon Electric's highly leveraged position flow through to PGE and its customers, despite the barriers that, hopefully, will be established. The wall, such as it is, has already been breached, so it is hardly inconsistent to acknowledge the benefits associated with those costs and risks which do impact PGE. This neither necessitates nor implies that ring fencing should be dismantled or that PGE should be tossed into the hopper with whatever parent company happens to be in charge. It is simply an acknowledgement of, and accounting for, the limitations of the established protections.

IV. Offered Benefits: New & Old

In rebuttal, TPG restates some of their original claimed benefits and adds a handful of additional items it claims are beneficial to customers. When taken as a whole, these benefits offer little to offset the serious risks of the proposed transaction.

A. Local Representation & Board Access

The crowing benefit of this transaction still appears to be the highly touted local representation on PGE's Board of Directors, and periodic access to PGE's Board for stakeholder groups. Regardless of how one values these benefits, it does not bode well that TPG waved away all of our concerns as unfounded, even ridiculous. TPG seems to expect us to believe this is the perfect transaction for PGE; it is an acquisition without flaw or risk. We wonder if this is how they address our concerns now, when they want our approval, how will they address our concerns once they are in the driver's seat?

B. $15 Million Rate Relief

The primary new offer is a rate credit of $15 million spread over three years. At $3 million per year (assuming equal ¢/kWh), this would offer customers a 0.2% rate reduction, or for residential customers, the savings would be less than 15¢ per month. This is small enough that few customers would even notice. We fully believe that TPG expects to make quite a bundle off this deal. Yet, this paltry sum doesn't come close to outweighing the risks posed by this transaction.

We believe that the risks in this deal outweigh those of the Sierra Pacific proposal. Sierra Pacific offered $97 million over seven years as a benefit of that merger. OPUC Order 00-702/Appendix B/6. The Scottish Power merger had a smaller rate benefit but included a provision that allowed the Commission to compel PacifiCorp to file a rate case, a provision that brings no value to this transaction, since PGE will want to file a rate case in two years to raise rates anyway. Though our opening testimony included such a provision, CUB/100/Jenks-Brown/35, we have since come to realize that between Port Westward's imminence and TPG's brief tenure, such a stipulation is meaningless in the context of this transaction.

The $15 million in rate benefits is not remotely commensurate with the risks involved.

C. Indemnification

While true indemnification from Enron and Western Energy Crisis liabilities would be lovely, the benefit from this indemnification is overstated by Mr. Davis. First Mr. Davis makes clear that without this transaction "PGE is not certain to be indemnified for any of these potential liabilities." OE/100/Davis/38. Of course, this can also be read as without this transaction, PGE may still be indemnified from these liabilities. Clearly, this indemnification is seen by the Enron creditors as a reasonable and necessary trade-off in order to enhance the value of PGE. If these same creditors are receiving stock in PGE as the alternative to this deal, they have every reason to want to enhance the value of PGE and can be expected to consider indemnification.

In addition, most of the things we are being indemnified from are things that are not the responsibility of customers. While Mr. Piro suggests that customers would be held liable for any penalties out of the California refund case, we believe that any penalties deriving from PGE's failure to comply with federal law and rules regarding wholesale trading of electricity must be the responsibility of shareholders. We feel comfortable that we will win that argument before the Commission should it ever get there.

Of course, it can be argued that even liabilities borne by shareholders will harm PGE financially, because of cost of capital concerns. It follows that, though the liabilities may not be forced onto customers' bills, they can still affect PGE's service. However, we need to recognize that if these penalties cannot be placed directly into rates, then they cannot indirectly be placed into rates by raising the cost of capital to reflect the financial harm to the company.

While customers do have a stake in a financially healthy company – one reason we are concerned with the double-leveraged nature of this deal – shareholders have the bigger stake in avoiding costs, including penalties, that are not recoverable in rates. Therefore, it should be recognized that the primary beneficiaries of the indemnification are TPG and Oregon Electric.

V. Somewhere Over the Rainbow – The Endgame

TPG ownership of PGE will be very short-lived; the Applicants make no bones about it. While many questions about this proposed transaction remain, one thing is certain: the exit is part and parcel of this deal. To separate the beginning and middle from the end of such a well-defined transition is nonsensical, and for those of us who are interested in the long-term health of PGE, it would be negligent. After discussing the transitional nature of this deal and its implications, we propose a condition for the Commission's consideration that recognizes that, while there may be a pot of gold at the end of the rainbow for TPG, it can only be achieved through assurances that PGE will emerge from this transaction as a stable, responsive enterprise for the good of employees and customers.

A. This Acquisition Is, By Definition, A Transition

This application is not an acquisition, but a transition. Transitions are not inherently bad, indeed they can present opportunities, and it is here that we are looking for a tangible benefit. TPG and Oregon Electric expect us to get lost in the minutiae, to focus very narrowly on this proposal, and forget the larger context. Yet, we know it is not enough to transition away from Enron; we must transition toward a stable utility that is responsive to the community it serves. While the proposed transaction creates all the wrong incentives for these short-term owners, it also presents an opportunity to move toward a stable responsive utility if we have the vision and the wisdom to make it so.

1. The Trouble With Short-Term Ownership

We have written at length about the troubles with short- term ownership, the perverse incentives for a short-term owner and how those incentives are not consistent with the interests of customers and employees. CUB/100/Jenks-Brown/8-12. The incentives for a short-term owner that compel drastic cuts in the short-term and forestall long-term investment are real. Any honest party with utility regulatory experience knows (or ought to know, even TPG's own witnesses!), utility regulation is more geared to denying costs over the long haul rather than trying to compel investment in the near term. No matter what TPG's remarkably self-interested and shameless testimony says to the contrary.

2. A Buyer & Seller Vs. An Owner & Operator

Yet it is not only CUB that sees TPG as a short-term owner; TPG itself speaks in terms of operating PGE simply as a means to an end, literally.

> In order for Oregon Electric to realize a profit on its investment, it must build value in PGE. PGE's value is a function of where the company is tomorrow and beyond, and that means that the company's long-term prospects will be an important part of its value when Oregon Electric decides to sell.
>
> - OE/100/McDermott/7

> Last, it should be obvious that hydroelectric plants with expired FERC licenses . . . would not be attractive to any prospective buyer.
>
> - OE/100/McDermott/46

Is it not surprising and perhaps alarming that, in defense of their caretaker role, TPG's major argument to the Commission is that a well-maintained utility will garner a greater capital gain when they sell it? How do you regulate someone like this? Add to the complexity the equally or perhaps more valid argument CUB makes, that the real incentive is to increase earnings in the short-term and let the next owner deal with the five years of neglect.

This acquisition is different than other acquisitions we have looked at, and TPG and Oregon Electric are different than other owners we have worked with. The distinction lies primarily in the difference of TPG and Oregon Electric as buyers & sellers as opposed to owners & operators. This is not to suggest that TPG and Oregon Electric would not be owning and operating PGE during their tenure, but earning the regulated rate of return by owning and operating PGE is not their core mission. Certainly TPG's core mission, indeed TPG's fiduciary duty to its investors, is to make as much money as possible turning PGE over in 5 to 10 years, not in owning and operating the utility for 50 or 100 years.

3. The Current Transition Could Get Us There Sooner

As much as TPG would have us fear the Enron bankruptcy, and as much uncertainty as there is in that process, at least we know that a publicly-traded, stand-alone entity is the expected outcome of that process. We know no such thing with TPG's ownership. Absent approval of the TPG application, PGE faces a likelihood of becoming a publicly-traded, Oregon-headquartered, independent company as its stock is distributed to Enron's creditors and into the market. Certainly, someone else could step forward to purchase PGE, but, if it is not a public body, we would have another ORS 757.511 proceeding as we are now, and who knows, the next time it might be somebody who wants PGE for keeps.

For PGE management, the last 5 years have been a merry-go-round of uncertainty, prospective buyers, and the shifting directives coming from each new suitor. It would be hard to argue that this has not had an impact on management's ability to do its job. TPG's proposed acquisition does not bring this merry-go round to a halt. In fact, no sooner than PGE management settles into TPG and Oregon Electric's leadership, PGE will be dragged back out onto the auction block, and management will, once again, be doing the delicate dance between the last suitor and the next one. Unless we demand it, TPG's ownership brings no more stability, and likely less stability, than redistribution of stock.

B. Exit Flexibility Benefits TPG, Not the Customer Or The Employee

Discussion of the endgame makes TPG nervous, because it is here that the windfall of PGE ownership comes to fruition. TPG's response to endgame suggestions is to argue that flexibility and optionality is in everyone's best interest. After all, who doesn't like having options in this high risk world?

> Several parties have suggested that they would like to see Oregon Electric commit to particular exit strategies and thus limit its options in the future. This course of action would be unwise. No one can predict today what circumstances may exist tomorrow in the industry, markets, or the State. The Commission has all the power it needs, and the intervenors all the rights they need, to thoroughly vet any proposed future sale of PGE, and customers would be best served by preserving all options for any future ownership.
>
> - OE/100/Davis/57

Let us be exceedingly clear: when TPG says that it is in everybody's best interest to retain all exit options for the future, what they are saying is that that flexibility is needed to create the biggest financial return for TPG. It is absurd to think that, without a prearranged deal, TPG would voluntarily forgo a larger financial gain in order to arrive at an exit that is in the best interests of the customers. We are not seduced in the least by the argument that giving TPG complete discretion to maximize its return will somehow benefit the customer or the employee. The preferred option for TPG is not necessarily the best option for customers.

C. Strategic Sale Not The Preferred Exit

After discussing a strategic merger as an exit option, Mr. Davis goes on to say:

> We were surprised that strong concern was expressed by some parties over the possibility of this option. Consequently, we do not see the wisdom of the Commission today doing anything that would restrict the option … for Oregon Electric to exit the investment in a certain way.
>
> - OE/100/Davis/56

If ever there was a misuse of the word "consequently" this would be it. In so many words, Mr. Davis is saying that because a strategic merger strongly concerns some parties, the Commission should leave that option wide open. Logic 101: If something concerns people, and you want to alleviate their concern, you protect them from it. We have had experience with strategic buyers, we have watched strategic buyers of other utilities, and if a strategic buyer concerns us, there's probably a darn good reason.

Our concern about how TPG would dispose of PGE stems from TPG's own analysis of the transaction. See CUB/100/Jenks-Brown/18-20. After we raised these issues, Mr. Davis responded in his rebuttal stating, "a strategic merger could present PGE customers with significant benefits in the form of cost savings from operational synergies." OE/100/Davis/56. Though TPG argues that a strategic sale could be in the best interest of PGE customers, we think this is unlikely. Having recently submitted the final brief, we hope, for the Multi State Process, Bob can attest to some of the difficulties in combining our local utility with one that operates in other states, let alone other nations. Additionally, these elusory synergies seem to be dwarfed by other factors such that the value of the synergies is negligible, if it exists at all.

1. Large, Multi-State Utilities Are More Difficult To Regulate

The Commission's jurisdiction only extends to the borders of the state. As it is, some of PGE's functions are regulated by FERC, other operating constraints are set by the Western Electricity Coordinating Council, and, of course, state and federal laws also apply. Add to this mix a few other state's regulatory bodies, unregulated and regulated affiliates operating in any number of states, and an electricity market in a state of flux, and you can imagine how interwoven and twisted issues can get.

a. A Tangled Web

Though this proposed acquisition is not a strategic purchase and PGE's functions are not being merged with any others, simply trying to untangle the web of TPG and Oregon Electric affiliates to protect PGE is proving time consuming, and far from simple.

A strategic merger involves far more interconnections and convoluted associations. The functions necessary to coordinate geographically or ideologically disparate limbs of a company, the complexities of multiple centers of control, the family tree of affiliates, as well as the additional vigilance necessary to keep the regulated business from subsidizing unregulated ones, all add both complexity and cost.

b. The PacifiCorp Case Study

PacifiCorp is an interesting case study. The Pacific Power, Utah Power merger envisioned synergies from combining a winter-peaking system with a summer-peaking one, and it seems there may be some genuine cost savings there. However, the Multi-State Process exemplifies at what cost those synergies were bought. The different states viewed their allotment of PacifiCorp's system differently, leaving PacifiCorp with a revenue hole that has taken countless hours of people's time to remedy.

Utah is growing far more rapidly than Oregon, and has been eyeing the Pacific Northwest's low-cost hydro for some time. Through the years of negotiations, CUB decided that in order to reach an agreement which protected the region's hydro resources for Northwest customers, it would be necessary to absorb the cost of Utah's load growth. It is a compromise, certainly, and ICNU argues it's a bad one, but, in order to reach a settlement, Utah's interests and its Commission had to be worked with.

It is not clear that Oregon's rates are as low as they would be had our low-cost hydro system never been absorbed into a larger utility, but the regulatory headache the merger produced has clearly cost the company, the Commission, and the intervenors a considerable sum.

2. Elusive Economies Of Scale

Despite the often-touted benefits of merger synergies, bigger is not necessarily better. Theoretically, a larger utility can spread its corporate functions over a greater number of customers, keeping costs down. While much has been made of the cost savings to customers of merging corporate functions, these so-called synergies seem to be neither as concrete nor as fruitful as they are often advertised to be. We might add that costs going down often involves employees being laid off.

a. Enron & Corporate Synergies

Enron, while not a utility, could still offer PGE synergies from both its generic business functions as well as its energy expertise. CUB/203/Dittmer/1, lists the functional areas shared by PGE and Enron, and those PGE will have to replace upon separation. Enron's Initial Comments in Docket UM 814, Enron's application to exercise influence over PGE, state:

> Our commitment to achieve at least $3 million per year in PGE cost of service reductions through administrative consolidation and application of Enron's expertise to PGE's operations…
>
> - CUB Exhibit 322

It isn't a glowing claim, and it definitely isn't a whole lot of money, but it certainly suggests some consolidation of corporate functions. Interestingly, in PGE's rebuttal, Mssrs. Tinker, Murray, and Hager allege that:

> Our best estimates today indicate that, rather than a "diseconomy," PGE's stand-alone costs to replace services provided by Enron will be slightly less than the direct and indirect charges allocated to PGE by Enron.
>
> - PGE/200/Tinker-Murray-Hager/17

It doesn't seem to be too far a stretch to assume that, if there are no diseconomies now, there probably weren't many economies to begin with. Of course, this flies in the face of Mr. Davis' hyping of the strategic sale where he says such a sale could "present PGE customers with significant benefits in the form of cost-savings from operational synergies." OE/100/Davis/56.

b. Size, Strategic Buyers, & Utility Synergies

CUB witness Jim Dittmer is not particularly surprised that PGE did not identify operational efficiencies with Enron. He states that, "[o]ver the last several years I and other members of my firm have skeptically reviewed many claimed 'merger savings' that were offered by merging utilities in an attempt to effectively recover a premium over book value being paid." CUB/200/Dittmer/10.

We took a closer look at the bigger is better argument, and it doesn't hold up very well. CUB Exhibit 323 shows graphs of private US utilities in terms of their residential rates and their size, as measured by residential sales. Don't bother looking for a trend, there isn't one. Rates do not clearly go down with the size of a utility. Each utility and each state have different circumstances, and there seems to be very little, if any, correlation between a utility's residential rates and the volume of its residential sales. So, corporate synergies are dubious, and utility synergies are even more so. Factors other than size clearly play a far greater role in a utility's rates.

3. Lose Local Focus

While it isn't something one can easily quantify in dollars and cents, a utility headquartered in and solely focused on Oregon and Oregon customers brings value. Its community participation and its place in the local economy are not affected by overarching corporate policies or directives designed for other states or other operations. Though the value of “local” is hard to measure, it is clearly something Oregonians are becoming increasingly interested in, and that value should not be blithely waved aside.

VI. CUB’s Proposals For Creating A Net Benefit

We highlight a few specific proposed conditions below, but in doing so we do not intend to reduce the significance of the conditions we set out in our opening testimony. CUB/100/Jenks-Brown/30-36.

A. Proposal For The Next Sale Of PGE

Because this proposal for temporary ownership presents some unique problems, we offer a unique condition that we feel creates benefits for the customer and the community. TPG’s ownership does not create certainty for PGE, other than the certainty that PGE will be sold again in the not too distant future. Therefore, we propose a condition that, while not excluding exit options, does create a path toward preferred exit options. As the Oregonian Newspaper opined:

> Oregon regulators should build into the Texas Pacific deal incentives for PGE’s eventual return [to] what it was – a well-run, investor-owned, stand-alone utility headquartered in Portland. If that happens, no one will have to search for the public benefit.
>
> \- CUB Exhibit 324

The condition would state that, if TPG does not create a publicly-traded corporation through a public stock offering, then some time prior to a bilateral sale of PGE to a strategic buyer, TPG will notify the City of Portland (or other established public entity to whom the City has transferred this right) and the City will have a period of time to decide to exercise an option to buy all PGE assets. If TPG disposes of PGE through a public offering, which TPG publicly says is a likely outcome, then this condition has no effect.

The condition allows the City an option to purchase PGE before a sale to a strategic buyer is made.

The City already has an option to buy of sorts through its powers of eminent domain, and as this power exists in state statute, public ownership has been deemed to be in the public interest. More specifically, the City has a similar option to purchase certain PacifiCorp assets as part of PacifiCorp's franchise agreement with the City.

We envision the price of the utility to be determined through an arbitration process. We also envision a commitment by the City to work out a regional governance plan and/or to assign the option right to a consortium of units of local government representative of PGE's service territory.

Without knowing what happens to PGE at the end of TPG's short ownership, it is impossible to know whether that short ownership is a good idea.

B. Commission-Ordered Audit

TPG asserts, and we doubt, that the existing powers of the Commission are adequate to deal with the natural incentives of a short-term owner, and to recognize and prevent overzealous cost-cutting and compel infrastructure investment. Our condition attempts to make us, who work before the Commission on a daily basis, feel as certain about the breadth of the Commission's powers as TPG, who is not familiar with Oregon utility regulation.

The condition has three parts:

1. Oregon Electric and PGE will make annual informational filings and presentations to the Commission regarding PGE's projected construction expenditures and O&M expenses. The information will compare each projected expense and expenditure

with that year's actual expenditure and will present a rolling three year average of these investments.

2. As directed by the Commission, PGE shareholders will pay for a management and operations audit by an independent auditor. Staff, in consultation with CUB, ICNU and any other interested party, will select the auditor and determine the scope of the audit. The scope of the audit could include a focus on strategic and operational planning, budgeting, capital expenditures, O&M expenditures, measures of work planned and performed, maintenance planning, performance and backlogs, performance measurements, and the organizational and management structure and the adequacy of personnel performance measures. There is no limit to the number of directed management audits, however no more than one audit will be initiated within a two-year period. If an audit is limited in scope and addresses a particular utility function, this provision does not preclude an additional audit on a different utility function within the two-year window.

3. Since TPG has already said it believes the Commission has the authority to protect customers from underinvestment, Oregon Electric and PGE will agree to make investments as ordered by the Commission as a result of the independent audit.

C. Hold Customers Harmless

To specifically hold customers harmless from the costs of a lowered credit rating as a result of the proposed financial structure, we want to see a promise that customers will be protected from such an event, not just in the first month of TPG ownership, but throughout that ownership. The condition would state that customers of PGE will be held harmless if PGE's revenue requirement is higher due to Oregon Electric's ownership of PGE.

D. Income Taxes and Interest Deduction

In order to acknowledge the risks and burdens of Oregon Electric's heavy debt load which flow through to customers, we suggest the following: PGE agrees to reflect the additional interest deduction at the Oregon Electric parent company level in order that income taxes being recovered, for ratemaking purposes, through PGE retail rates more closely approximate the taxes actually being paid by Oregon Electric to federal and state taxing authorities.

E. Rate Credit

The rate credit issue is a moving target, because TPG has not made sufficient headway in responding to our concerns and in working to reduce the identified risks. Without knowing which risks are still outstanding, it is difficult to attempt to monetize those risks in an attempt to compensate customers. In our view, the required rate credit is more or less dependant upon which of the conditions TPG agrees to.

Nevertheless, looking back at precedent, we think that this transaction creates more risk than the Sierra Pacific transaction. In that transaction, Sierra Pacific agreed to provide $97 million dollars in rate benefit over seven years. Since this transaction carries with it more problems, we assert that the starting place for rate credits is greater than $ 97 million.

Scottish Power agreed to a smaller rate credit, but parties negotiated additional conditions including one that allowed the Commission to compel PacifiCorp to file a rate case and carry the burden of proof. That condition carried additional value. A similar rate case provision is of no value in this case for a variety of reasons. PGE will be filing a rate case in a very few years in order to rate base Port Westward and TPG may not own PGE long enough thereafter to make such a rate case condition worth the paper it is printed on.

F. Offered Conditions

CUB Exhibit 325 is condition language for these highlighted proposed conditions and a few more. These conditions assume a satisfactory settlement of the appropriate ring-fencing conditions. CUB also supports conditions suggested by Renewable Northwest Project, the Hydropower Reform Coalition, the City of Portland, the League of Oregon Cities, and the low-income assistance condition recommended by the low-income advocates.

VII. Conclusion

CUB opposes this transaction. So there is no confusion, as the proposed acquisition currently stands, we have no use for this temporary owner and the risks it brings. We will attempt to find some benefit in this deal by focusing on how to make PGE a stable and responsive utility. Failing that, however, we can do without this transaction.

Excerps from:

FORM 10−K
CONTINENTAL AIRLINES INC /DE/ − CAL
Filed: April 13, 1995 (period: December 31, 1994)

Annual report which provides a comprehensive overview of the company for the past year

Business Strategy
Continental has developed a new strategic program, the Go Forward Plan, designed to strengthen the Company's domestic hub operations, increase revenues and cash flows, improve profitability by shrinking excess capacity, and enhance customer service. Since the Reorganization, Continental has not been profitable. In late 1993 and throughout 1994, the Company significantly reduced its presence in Denver, which had historically been unprofitable for the Company, and redeployed aircraft and other resources to the eastern United States in connection with the expansion of Continental Lite. Demand for Continental Lite, particularly in linear markets, proved insufficient to absorb the Company's excess capacity, and Continental Lite was not profitable in 1994. Overcapacity worsened in the latter half of 1994 as Continental's fleet expanded due to deliveries of new jet aircraft.

During the fourth quarter of 1994, the Company determined that a new strategic plan was needed to return the Company to profitability and strengthen its balance sheet. The Go Forward Plan has four key strategic components: Fly to Win, Fund the Future, Make Reliability a Reality and Working Together.

Fly to Win. Continental intends to maximize efficiencies and revenues by:

− − − − Strengthening its domestic hub operations by adjusting frequencies and improving schedules.

− − − − Pricing fares commensurate with market demand and elasticity.

− − − − Reducing Continental Lite flying by approximately one−third, primarily in linear markets which, at Continental Lite's peak capacity in 1994, represented approximately 35% of the Continental Lite system but ccounted for an estimated 70% of Continental Lite's 1994 losses.

− − − − Downgauging aircraft and reducing overall capacity by removing from service 24 less−efficient widebody aircraft and accelerating the retirement of 23 older Stage II narrowbody aircraft during 1995.

− − − − Modernizing its domestic fleet by placing in service 27 new, more efficient aircraft in 1995.

− − − − Improving customer service by returning Continental's frequent flyer program ("OnePass") to its 1993 terms.

− − − − Reducing staff (at all levels) by approximately 4,000 positions to match the reduction in capacity and to eliminate non−value added activities.

Fund the Future. The Company is taking steps to improve liquidity and, in the long term, de−leverage the balance sheet by:

− − − − Adjusting Continental’s fleet plan by deferring certain aircraft deliveries, canceling options on aircraft deliveries and removing 24 widebody aircraft and 30 narrowbody aircraft (23 of which are being retired on an accelerated schedule) from service in 1995.

− − − − Negotiating amendments to certain debt and lease agreements to reduce cash requirements in 1995 and 1996.

− − − − Evaluating the potential disposition of certain non−strategic assets.

See Item 7. “Management’s Discussion and Analysis of Financial Conditionand Results of Operations. Liquidity and Capital Commitments”.

Make Reliability a Reality. Continental has placed renewed emphasis on reliability and has named two executives to improve its on−time performance, baggage handling and customer satisfaction. Employees will have the opportunity to earn extra pay each month that the Company meets certain on−time performance targets as measured by the DOT. In order to enhance consumer perception of Continental’s reliability, consistency and quality, the Company is completing the refurbishment of its terminal spaces and fleet interiors and exteriors during the first half of 1995. In addition, the Company is installing new passenger in−flight telecommunications and computer facilities on all jet aircraft and expects that installation will be substantially completed by the end of 1995.

Working Together. Senior management has instituted a new open−door policy with its employees designed to improve the working environment and encourage all employees to work together as a team to improve operational performance and customer service. In support of the new policy, senior management has hosted hundreds of employees for informal get−togethers and discussion sessions in the executive offices, and more of these sessions are scheduled. In addition, the Company has hired new senior executives with successful records at profitable companies in the areas of pricing, scheduling, distribution, human resources, airport services, law and finance.

Continental’s alliance with America West is producing further efficiencies for the two carriers. Task forces have been established to coordinate and optimize benefits in the areas of code−sharing, frequent flyer programs, maintenance procurement, station operations and information systems.

Employees

Labor costs are a significant variable that can substantially impact airline results. For the year 1994, labor costs constituted approximately 27.0% of total operating expenses. While there can be no assurance that Continental’s generally good labor relations and high labor productivity experienced in the past five years will continue, Continental’s management has established as a significant component of the Go Forward Plan the preservation of good employee relations.

As of December 31, 1994, Continental had approximately 37,800 full−time equivalent employees (including approximately 4,800 pilots, 6,400 flight attendants, 4,900 mechanics, 100 dispatchers, 17,300 customer service agents, reservations agents, ramp and other airport personnel and 4,300 management and clerical employees), approximately 29.8% of whom were represented by unions.

The Company and the Independent Association of Continental Pilots (“IACP”) are negotiating an initial collective bargaining agreement for the pilots. Negotiations have progressed to mediated collective bargaining with the National Mediation Board (“NMB”) − a normal and usual part of the airline labor negotiation process. The Company is hopeful that a mutually acceptable agreement can be reached without adverse employee work actions; however, the ultimate outcome of the Company’s negotiations with the IACP is unknown at this time.

In 1992, Continental and its flight attendants entered into a collective bargaining agreement with the International Association of Machinists and Aerospace Workers (“IAM”) that has been ratified by the Continental flight attendants and becomes amendable in 1996. In 1993, the NMB ruled that the Express flight attendants are also represented by the IAM. Negotiations between Continental and the IAM have commenced, but the parties have not yet reached an agreement. The Company is hopeful that the parties can reach an agreement without adverse employee work actions; however, the ultimate outcome is unknown at this time. CMI’s flight attendants are also represented by the IAM, but are covered under a separate four−year contract that was signed in September 1992 and becomes amendable in September 1996.

Continental’s dispatchers are represented by the Transport Workers Union which also represents the dispatchers of Express. CMI’s dispatchers are not represented by a union. CMI’s mechanics and mechanic−related employees are represented by the International Brotherhood of Teamsters (“IBT”) under a collective bargaining agreement signed in April 1994 which becomes amendable in March 1997. The IBT also represents CMI’s agent classification employees located on Guam whose collective bargaining agreement was also signed in April 1994 and becomes amendable in March 1997.

The other employees of Continental, Express and CMI are not represented by unions and are not covered by collective bargaining agreements.

The Company has taken several cost containment actions affecting employees. In 1992, Continental and its subsidiaries implemented across−the−board salary and wage reductions for all employees, ranging from 5.0% of pay at the lowest level of compensation to approximately 22.5% of base pay for Continental’s senior management. The reductions, which lowered payroll expense by approximately 10.0%, were restored in equal increments in December 1992, April 1993, April 1994 and July 1994. In January 1995, Continental determined not to make any longevity pay increases and to eliminate approximately 4,000 positions, including executive and management positions, during 1995.

CUB/304
Jenks-Brown/1

FROM WORST TO FIRST

Behind the Scenes of Continental's Remarkable Comeback

GORDON BETHUNE
WITH SCOTT HULER

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We could see from the start that it wasn't going to be easy. We had problems with *where* we flew, we had problems with *what* we flew, we had problems with *how* we flew . . . and we had problems with who was flying.

Fly to Win is about our market: determining our target market, making our product fit that market in price and position, finding the amenities our customers want and will pay for, and making it easy for our customers to get our product.

Stop Doing Things That Lose Money

It was easy to get lost trying to scramble around and decide what had to be done first. So we started having meetings, me and a lot of the people I had hired to get us out of this mess. We'd talk about this, we'd talk about that, and then in one meeting, Greg Brenneman finally said, "Well, why don't we just stop doing things that lose money?"

You know, it was a damn good idea. It was a remarkably good idea. And when people ask me to outline the first step in recovering from the kind of disaster area we had become, that's what I tell them. It's what I suggest they do if they find themselves in a similar spot: Stop doing things that lose money.

Take a moment to consider why your company is in business in the first place. Yes, certainly because you love the business of flying airplanes or making pizzas or fixing watches or selling shoes or whatever it is you're doing. But if you're in business, you're in it to make a profit. You've got to be; otherwise you're going out of business.

Get the Money

The first step in making a profit is to stop doing the things that are specifically causing you *not* to make a profit. Stop doing the things that *lose* money. That is, stop selling the stuff that nobody wants to buy at a price that will generate a fair profit. It seems simple, yet that clear-cut statement got us all to stop and look at what we were doing.

As for what we were doing that was losing money, well, we had a lot of choices. We had been losing money for a decade and a half, and just about everything we did wasn't working.

Eighteen percent of our flying was cash negative. Do you get that? That means you could put the parking brake on, evacuate the airplane, and lose less money than you would by flying the damn thing.

To stop losing money, one of the things we had to do was stop flying that 18 percent of our routes. Which meant we had to take a good hard look at where we flew, how often we flew, and how we flew. Which immediately brought up Continental Lite, our low-cost airline within an airline that had become, sadly, a colossal failure.

Don't Be Telling People What They Want to Buy

In the early 1990s, Continental, with its profound focus on cost saving, still wasn't making a profit, and it still wasn't a successful airline. Companies like Southwest were doing a better job of providing cheap fares to places people wanted to fly.

So the people running the Continental got the idea to turn a third of our operation into an all-cheap-seat airline. That is, if Southwest could run a low-cost airline and make money, then maybe we needed to start our own low-cost airline. That's what we did.

We invented a product called Continental Lite, and we defined it.

Continental Lite, we said, would have "Continental Lite" written on the side of the airplane to identify it. A good start.

To keep the costs per available seat mile low, we'll take out the 12 first-class seats and replace them with 18 coach seats. That way we'll get six extra seats. Divide that by the cost, which remained the same, and we'll reduce our average seat cost per mile commensurately.

That's good.

We'll increase airplane use by flying more each day, and we won't spend a lot of time on the ground, so we'll start out real early in the morning and we'll finish up real late at night. If the quick turnaround means the plane might not be as clean as it ought to be, well, the flight will be cheap, so who's going to care?

So far so good. We'll be flying a lot more miles, with a greater number of seats, at the same cost for the airplane.

But according to our projections, we needed still more cost reductions for CAL Lite to turn a profit. So we looked at the food

Excerpts from:

FORM 10−K405
VERITAS SOFTWARE TECHNOLOGY CORP − seg
Filed: August 23, 2000 (period: June 30, 2000)

Annual report. The Regulation S−K Item 405 box on the cover page is checked

EMPLOYEES

At June 30, 2000, the number of persons employed worldwide by Seagate was approximately 60,000 of which approximately 44,000 were located in Seagate's Asia Pacific operations. In addition, Seagate makes use of supplemental employees, principally in manufacturing, who are hired on an as−needed basis. Management believes that the future success of Seagate will depend in part on its ability to attract and retain qualified employees at all levels, of which there can be no assurance. Seagate believes that its employee relations are good.

Excerpts from:

FORM 10−K
SEAGATE TECHNOLOGY − STX
Filed: August 21, 2003 (period: June 27, 2003)

Employees

At June 27, 2003, we employed approximately 43,000 persons worldwide, of which approximately 33,000 employees were located in our Asian operations. In addition, we make use of temporary employees, principally in manufacturing, who are hired on an as−needed basis. We believe that our future success will depend in part on our ability to attract and retain qualified employees at all levels, and even then we cannot assure you of any such success. We believe that our employee relations are good.

Excerpts from:

FORM 10−K405
MEMC ELECTRONIC MATERIALS INC − WFR
Filed: March 23, 2001 (period: December 31, 2000)

Annual report. The Regulation S−K Item 405 box on the cover page is checked

Employees

At December 31, 2000, we had approximately 6,600 full−time employees and 370 temporary workers worldwide. We have not experienced any material work stoppages at any of our facilities during the last several years. We believe our relationships with employees are satisfactory.

Excerpts from:
FORM 10−K
MEMC ELECTRONIC MATERIALS INC − WFR
Filed: March 21, 2003 (period: December 31, 2002)

Annual report which provides a comprehensive overview of the company for the past year

Employees

At December 31, 2002, we had approximately 4,600 full time employees and 100 temporary workers worldwide. We have approximately 2,000 unionized employees in our St. Peters, Missouri, Pasadena, Texas, South Korea and Italy facilities. We have not experienced any material work stoppages at any of our facilities during the last several years.

Excerpts from:

FORM 10−K
J CREW GROUP INC − N/A
Filed: May 04, 1998 (period: January 31, 1998)

Annual report which provides a comprehensive overview of the company for the past year

EMPLOYEES

The Company focuses significant resources on the selection and training of sales associates in both its mail order, retail and factory operations. Sales associates are required to be familiar with the full range of merchandise of the business in which they are working and have the ability to assist customers with merchandise selection. Both retail and factory store management are compensated in a combination of annual salary plus performance−based bonuses. Retail, telemarketing and factory associates are compensated on an hourly basis and may earn team−based performance incentives.

At January 31, 1998, the Company had approximately 6,200 associates, of whom approximately 4,200 were full−time associates and 2,000 were part−time associates. In addition, approximately 3,000 associates are hired on a seasonal basis to meet demand during the peak holiday buying season. None of the associates employed by J. Crew Mail Order, J. Crew Retail, J. Crew Factory Outlets or C&W are represented by a union. Approximately 240 warehouse employees at PCP are represented by the Teamsters under a collective bargaining agreement which expires in June 1999. The Company believes that its relationship with its associates is good.

Excerpts from:
FORM 10−K405
J CREW GROUP INC − N/A
Filed: April 30, 1999 (period: January 30, 1999)

Annual report. The Regulation S−K Item 405 box on the cover page is checked

Employees

The Company focuses significant resources on the selection and training of sales associates in both its mail order, retail and factory operations. Sales associates are required to be familiar with the full range of merchandise of the business in which they are working and have the ability to assist customers with merchandise selection. Both retail and factory store management are compensated in a combination of annual salary plus performance−based bonuses. Retail, telemarketing and factory associates are compensated on an hourly basis and may earn team−based performance incentives.

At January 30, 1999, the Company had approximately 5,400 associates, of whom approximately 2,600 were full−time associates and 2,800 were part−time associates. In addition, approximately 3,500 associates are hired on a seasonal basis to meet demand during the peak holiday buying season. None of the associates employed by J. Crew are represented by a union. The Company believes that its relationship with its associates is good.

Oregonian, The (Portland, OR)
July 20, 1999

GLOW OF US WEST-QWEST MERGER DIMS

Author: SU-JIN YIM - The Oregonian
Edition: SUNRISE
Section: BUSINESS
Page: C01
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US WEST QWEST
Profile Statistics
Estimated printed pages: 4

Correction: PUBLISHED CORRECTION RAN 7/21/99, FOLLOWS:
* An article in Tuesday's Business section misstated the size of a combined **Qwest** Communications International Inc. and **US West** Inc. The new company, if merged, would have a market capitalization of about $65 billion.

Article Text:

Summary: Residential phone customers in Oregon and the **west** may see little benefit or change from the telecommunication firms' union

The residential phone customers most likely to see direct benefits from the **merger** of **US West** and **Qwest** Communications International Inc. don't live in Oregon. They live in places on the East Coast and Midwest, where the merged company intends to offer an array of new services.

Under the gilt and glamour of Sunday's announcement that **US West** will merge with a Denver long-distance upstart lie few direct or near-term changes for Oregon's residential customers hoping for a choice in local phone service, according to analysts.

"This **merger** doesn't have anything to do with local phone service," said Jeffrey Kagan, a telecommunications industry analyst in Atlanta.

Instead, the deal helps position both **US West** and **Qwest** Communications International Inc. for a future when voice calls are just one of many services riding over a video-, data- and Internet-focused communications network. In that world, large business customers and others with huge communications needs are more lucrative than average phone residential consumers.

US West ended a monthlong bidding contest Sunday to ensure its perch in that future when it accepted **Qwest**'s bid, creating a $65 billion-a-year company with 64,000 employees worldwide. Global Crossing Ltd., **US West**'s original suitor, agreed to walk away with half its initial deal, buying long-distance company Frontier Corp. If the deal goes through, **Qwest** will pay $69 a share for **US West**. **US West** shares closed Monday at $59.75.
US West, the dominant phone company in Oregon with 1.37 million customers, was one of the last local phone companies to join the **merger** bonanza in the rapidly morphing telecommunications industry. Even though it's saddled with a far-flung, but sparsely populated, geographic area, the company was attractive to new long-distance suitors in part because they needed its 25 million customers. But the deal also raises the question of the legacy of the 1996 Telecommunications Act. The federal act was supposed to open up the monopolistic local phone industry. Instead, it spawned countless **mergers** among traditional phone companies but no major regions where residential customers have a choice in local phone service.

Even **Qwest**'s initial plans focus on expanding its data services to 25 new cities outside its region. Most of those cities lie in Bell Atlantic and SBC-Ameritech territory, and the services primarily will target business customers.

The deal prompts the question: What happened to the concept of local phone competition for all?

Widespread local phone competition will emerge, analysts say, just more slowly and in a different form than expected.

"Their announced intention to expand their efforts out of region is another step toward there being more competition in a general sense," said securities analyst Bob Wilkes of Brown Brothers Harriman in New York. "I don't think we're as far as people expected back in 96, but we're starting to see some progress."

AT&T Corp. and SBC-Ameritech say they want to offer local phone service in Portland but face business or legal hurdles. AT&T, which plans to offer phone service over its cable network, wants the city and Multnomah County to remove a key condition of its cable operating franchise. That argument is in the courts. SBC and Ameritech, which still are completing their **merger**, are at least a year to 18 months away from offering local service in Portland.

West Coast may lose choice

US West's **merger** with **Qwest** could even cost Oregonians, and other **West** Coast customers, a choice in long-distance carriers. That's because **US West** has not convinced federal regulators that its local markets are open to competition, a requirement for entering the long-distance market. To avoid regulatory disapproval, the companies have volunteered to shed **Qwest**'s long-distance customers in **US West** territory.

"This isn't going to change the customer experience for **US West** customers already using advanced services," Kagan said. "What it does is allow **US West** to prepare for the future by instantly having a nationwide network."

Access to that network means **US West** will be able to handle more of the demands placed on it by growing numbers of Internet and data users, said corporate spokesman David Beigie.

Beigie said the merged company's plan to offer services in the territories of rival companies should promote competition in **US West**'s home territory. "If **US West** and **Qwest** step it up out of region, that's going to be the fire that gets lit under the fannies of our competitors to get moving on competing in our region," Beigie said. "If competitors don't follow suit, it's to their peril. We're going to take their market share."

Securities analyst Thomas Friedberg of Janco Partners Inc. in Denver agreed, saying the company, which historically has been criticized for delaying competition in its home region, will have more incentive to open its own markets in exchange for access to other geographic areas.

Competition may be stifled

"**Qwest** recognizes that you aren't going to be able to effectively compete in other people's markets unless you have leverage within the local customer base that other people want to interconnect to," Friedberg said. "A logical conclusion is if I have a significant installed customer base that others want access to, giving those people access may be a quid pro quo to their customers."

Rather than sparking competition, Ron Eachus, chairman of the Oregon Public Utility Commission, said the **merger** will stifle it.

"It just increases the pressure to delay competition. **US West**'s mode of operation has been to do everything it can, use every venue it can, at every opportunity it has, to delay competition," Eachus said. "There is no indication whatsoever that this **merger** will change that approach. In fact, it increases the pressure, because they now need more revenue to pay off the **merger** and make investments elsewhere. They get that revenue from their monopoly service."

US West does not need approval from Oregon's PUC, but it will need the OK of a handful of other states, the Federal Communications Commission and the U.S. Department of Justice.

Still, the **Qwest**deal is a better option than its initial plans to merge wit h Global Crossing, a young underseas fiber company out of Bermuda, said PUC commissioner Joan Smith.

"This matchup makes more sense for Oregon and customers than the Global Crossing proposal did," Smith said in a statement. "I believe a new service culture and **Qwest** interest in broadband mean good things for Oregon's telecommunications future."

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IS LIFE BETTER HERE?

A CONSUMER SURVEY OF U S WEST LOCAL TELEPHONE SERVICE QUALITY

EMBARGED FOR RELEASE
1:00 P.M., PST
DECEMBER 17, 1998

U S WEST TERRITORY CONSUMER WATCH
ARIZONA CITIZEN ACTION
COLORADO PIRG
MINNESOTA COACT
CITIZENS' UTILITY BOARD OF OREGON
WASHINGTON CITIZEN ACTION

North Dakota

The North Dakota Public Service Commission received more than 1300 complaints against U S WEST between 1990 and September 1997. Complaints per year follow: 1990, 195; 1991, 2645; 1992, 200; 1993, 173; 1994, 185; 1995, 109; 1996, 107; Jan.-Sept. 1997, 63.[76]

Oregon

Standards

The Oregon Public Utilities Commission (PUC) has adopted service quality standards similar to the ROC standards, but the Oregon legislature has refused to give the PUC authority to directly levy fines to enforce the standards.

Performance

The PUC experienced a 77% increase in complaints against U S WEST from May to October 1997. Many of the complaints related to the company's inability to provide service on time. Held orders constituted the central concern of consumers as the year advanced. In October, the PUC held a hearing to address consumer complaints. At the time, U S WEST had more than 720 held orders, five times the PUC-allowed limit; many individuals were waiting four to six weeks for a dial tone.[77]

In that month, the PUC issued an order finding U S WEST in violation of held order service quality standards. According to the PUC, its "order led to lengthy discussions between USWC and the Commission staff. The result of these discussions was an agreement, accepted by the Commission on December 2, which requires USWC to comply with the held order service standard by September of 1999. The company also agreed to meet quarterly held order targets and to pay customer reparations of up to $3.6 million annually for failure to meet the targets. Without the reparation agreement, the Commission would have had to seek penalties through a Circuit Court action. Any fine levied by a court would have gone into the State of Oregon General Fund, rather than to customers."[78]

In March 1998, the PUC announced that U S WEST had missed service quality marks for two consecutive months. It failed to clear customer trouble reports within 48 hours in less than 90% of all trouble reports. That standard is only temporary and lower than the normal standard, and was granted to the company in light of its apparent efforts to resolve its held order problem. The permanent standard provides for a 95% clearance rate of customer trouble reports.

During the CWA strike of U S WEST in August 1998, the company refused to abide by its obligation to provide $100 credit per month or cell phone service to customers whose lines were not installed on time. Instead, the company sought to sell dissatisfied customers cell phone service. In an agreement with the PUC, the company agreed to provide credit to customers affected by the strike towards purchase of U S WEST cell phone service.

In late October 1998, the PUC announced that only few U S WEST wire centers met PUC standards for basic service quality. PUC rules allow only 2 trouble reports per 100 lines per wire center per month in any 12-month period. Only 16 of 77 U S WEST wire centers met this standard.

Table 11

U S WEST Service Quality: Oregon At-fault complaints per 1000 customers	1994	1995	1996	1997	Jan-Jun. 1998
U S WEST	0.358	0.511	1.4882	2.1	0.61
GTE	0.328	0.177	0.3086	0.48	0.21
Pacific Telecom	0.337	0.106	0.6119	0.9	--
United/Sprint	0.136	0.085	0.0604	0.12	0.04
Century Tel					0.4

Source: Oregon Public Utility Commission

South Dakota

Standards

South Dakota, which passed a new telecommunications law in 1998, is in the process of updating its rules (SD Rules, Chapter 20:10:33) on telecommunications service quality, which would apply to all carriers in the state.

U S WEST Territory Consumer Watch was unable to collect other information on the state.

Utah

Performance

According to the Public Service Commission, as of the end of summer 1998, U S WEST still controlled more than 95% of all access lines in the state. In October 1998, the PSC estimated that U S WEST would earn in 1998 5.5% in excess of its guaranteed rate of return of 11.5%. The PSC further calculated that U S WEST would collect an excess of $29 million from Utah's consumers. As a consequence of extra earnings, which actually date back ten years, U S WEST and the Division of Public Utilities (DPU) and the Committee of Consumer Services of the state Department of Commerce reached an accord in November 1998 that anticipated U S WEST refunding $53 million to customers over approximately three years.[79] According to news accounts, the DPU asserted that U S WEST had misled and withheld information from state regulators. The agreement must be approved by the PSC.

Held orders

According to the DPU, held orders were continually dropping from 1995 through 1997. At the end of November 1995, 1163 held orders were registered; in January 1996, that number had dropped to 421. It dropped again to 202 as of December 1996. As of late August 1997, the year-to-date average number of held orders between 31 and 60 days was steady at 13%, with held orders over 60 days at 7% for 1997. U S WEST averaged 90% of appointments met.

Customer Complaints

In 1996, the Utah Department of Commerce, Division of Public Utilities reported that it

Oakridge Special Public Meeting
To Look At Telephone Infrastructure Issues

March 29, 1999 (1999-014)

Contacts: Ron Eachus, Chairman, 503 378-6611; Roger Hamilton, Commissioner, 503 378-6611; Joan H. Smith, commissioner, 503 378-6611; Ron Karten, Public Information Officer, 503 378-8962

Salem, Ore. – The Oregon Public Utility Commission (OPUC) is scheduled to hold a Special Public Meeting in Oakridge to hear from the community about telecommunications infrastructure and service quality problems. Commissioners will convene the hearing at the City Fire Hall on Wednesday evening, March 31 at 7:00 PM.

In addition to Commission comment on the recent history of U S WEST service quality problems in the area, the meeting will include comments by Oakridge Mayor Don Hampton and Ruth Ann Howden of the Eugene Free Community Network. Other elected officials representing the area also have been invited to attend and speak.

The Special Public Meeting comes in response to numerous complaints about the service quality in the area provided by U S WEST Communications Inc. According to complaints the Commission has received in recent months, the company has failed to provide internet and other digital services to customers.

The Commission has determined that the failure comes from a lack of circuits between the switches in Oakridge and Eugene. The same problem exists between Sutherlin and Roseburg and between Florence and both Corvallis and Eugene.

Across the state, U S WEST is operating outdated analog switching equipment in 11 wire centers, including Klamath Falls, Medford, Grants Pass, Roseburg, Springfield, Corvallis, Albany, Oregon City and three in Portland. According to Commission staff, the company has been getting $14 million annually in over-recovery of expenses because depreciation in rates assumed replacement of the switches. The company promised to replace 13 analog switches with digital switches between 1996-2000, but only two have been replaced, and the company has not announced plans to replace any of the others. The analog switches are so old that parts are no longer made for repair or replacement.

In addition, the company’s 1998 Construction budget reported planned upgrades to switches serving Pendleton and Baker City, Roseburg and Oakridge but neither were completed and both areas are now experiencing capacity shortages. The Commission has opened an investigation into the company’s 1998 and 1999 Construction budgets to see if other areas of the state might soon be facing similar problems for similar reasons.

Across the state for the last three years, no more than 20 of the company’s 77 switches have at any one time met Commission standards requiring less than two complaints per 100 lines on a 12-month rolling average.

Early this month, the Commission ordered U S WEST to "immediately take whatever actions are necessary" to ensure that Mercy Medical Center in Roseburg receive the voice and data phone service it needs. The Commission also required the company to complete alterations to its Roseburg central office switch to provide adequate capacity by March 12. The company was ordered to increase, by March 20, the number of circuits between Roseburg, Sutherlin and Winston in order to provide the level of service required in Commission rules.

Following the March 20 deadline, the Commission’s senior Telecommunications engineer investigated the company’s central offices in the Roseburg and Sutherlin areas to insure that the work had been completed. While Roseburg lines are much improved, they still need work. The Roseburg-Sutherlin route remains in need of immediate augmentation due to lack of capacity.

This is one of four telecommunications infrastructure meetings the Commission has scheduled. The Commission was in La Grande on March 18, and will be in Roseburg, on April 8, and in Newport on April 29.

Commission Fears Roseburg Telephone Problems Repeat In Grants Pass

April 16, 1999 (1999-016)

Contacts: Ron Eachus, Chairman, 503 378-6611; Roger Hamilton, Commissioner, 503 378-6611; Joan H. Smith, Commissioner, 503 378-6611; Ron Karten, Public Information Officer, 503 378-8962

Salem, Ore. – The Oregon Public Utility Commission (OPUC) today said it was increasingly concerned that the community of Grants Pass and surrounding areas will face the same type of telephone call blockage problems recently experienced in Roseburg.

The Commission said it had already received 25 "circuits busy" complaints this month about the telephone service provided by U S WEST Communications, Inc. in the Grants Pass exchange. Complaints increased from four in January and six in February to 23 in March.

When there is insufficient capacity in the system call blocking results and the customer receives a "circuits busy" signal.

The Commission said it would send its telecommunications engineer to Grants Pass to test and inspect the facilities and to evaluate any U S WEST plans to improve the situation.

Roseburg and the surrounding area recently experienced several months of high levels of call blocking, prompting the Mercy Medical Center and the Sutherlin Police Department to complain that it was a potentially life-threatening situation.

In Roseburg, the Commission ordered the company to "immediately take whatever actions are necessary" to ensure that the hospital receive the voice and data phone service it needs. The Commission also required the company to complete alterations to its Roseburg central office switch to provide adequate capacity. The company was ordered to increase the number of circuits between Roseburg, Sutherlin, and Winston in order to provide the level of service required in Commission rules.

Like Roseburg, Grants Pass is served by an older analog switch, one of 13 still in operation in Oregon, all in U S WEST’s territory. U S WEST requested and received $14 million in accelerated depreciation from the Commission so the switches could be replaced by 2000. However, the company has replaced only two, both in the Portland area, and will not replace any of the others by the end of 2000.

Commissioners said they were convinced timely replacement of the analog switches in both Roseburg and Grants Pass could have prevented current problems.

"If they had replaced the old switches with new digital technology as they said they would, it’s doubtful the communities would have a problem," said Ron Eachus, Commission Chairman. "When you put in a new switch it is reasonable to assume you also will include additional future capacity. Plus, upgrading a digital switch is a lot faster than upgrading a labor intensive analog switch."

"The problem is that when they don’t put in the new digital switch as planned, they have to spend money to upgrade the old analog switch and that in turn delays installation of a new digital switch even more," said Commissioner Roger Hamilton. "In the longer run, this is a penny wise, pound foolish approach."

Despite the company's efforts to improve the Roseburg switch, the Commission continues to receive "circuits busy" complaints for the area.

In March, the Commission opened an investigation into why U S WEST has not replaced the remaining analog switches as it planned to do earlier.

Also last month, the Commission opened an investigation into the company's 1998 and 1999 construction budgets after determining that other uncompleted projects in the 1998 budget also could have prevented the problems cited in the Roseburg area and elsewhere in the state.

Commission Seeks Compensation Plan From U S WEST For Roseburg Residents

May 10, 1999 (1999-020)

Contacts: Ron Eachus, Chairman, 503 378-6611; Roger Hamilton, Commissioner 503 378-6611; Joan H. Smith, Commissioner, 503 378-6611; Ron Karten, Public Information Officer, 503 378-8962

Salem, Ore. – The Oregon Public Utility Commission staff will recommend acceptance of a U S WEST Communications, Inc. proposal to rely on the individual complaint process to compensate customers for poor service, provided the company makes it easy for customers to file complaints and offers a written commitment to provide a new digital switch by the end of 2000.

The staff made the proposal in a letter to U S WEST after the company told the Commission it would not provide blanket credits to all customers in the Roseburg area.

During an April 8 hearing in Roseburg, when the company agreed the problems were pervasive to the area, the Commission maintained its rules provided for billing credits to all customers and urged the company to develop a plan that did not rely on making individual customers file formal complaints.

Since then, the company announced it would replace the old analog switch with a digital switch next year, reversing previous statements that Roseburg would have to wait until at least 2003 before the replacement.

Then, in a May 6 reply to the Commission, the company denied any legal obligation to compensate customers and said it found a "blanket, indiscriminate refund" unappealing because it would be difficult to identify customers with substantial blockage problems and to quantify the amount of trouble.

But, the company said, "solely as a matter of accommodating customers," customers who have experienced substantial blockage problems should receive some sort of compensation but it would approach the problem on an individual basis.

U S WEST maintains that the existing tariff provides compensation only when there is a loss of local exchange service. The Commission, however, believes its rules on call blocking provide for billing credits and could be applied to all customers in the area since the problem was pervasive.

In a letter to U S WEST, the staff said it does not agree with the company’s assessment of its legal responsibility but it was encouraged by the company’s agreement to provide billing credits to customers who have experienced significant blockage problems.

The letter proposed that billing credits take into account the length of time that blockage occurred with one-month credits at a minimum to affected customers; that customers who have already filed informal as well as formal complaints be automatically included on the list of those to be compensated; and that those who have not filed a complaint be able to do so by filing a simple form.

"We’re disappointed U S WEST threw down the gauntlet on the legal issues and put the burden on the individual customer even though it admits the problems were pervasive," Commission Chairman Ron Eachus said. "But what the community really wants is adequate service and if it will put the switch in and make it easy for customers to file complaints, then maybe the staff proposal will work."

The staff compensation proposal is contingent on the company providing a written commitment to installing the digital switch, as pledged, in press announcements. "In the past, the company has often equivocated when pledging modernization," said Commissioner Roger Hamilton. "We want to make sure there’s a written commitment before we accept putting the burden for compensation on the customer."

January 5, 2000 Beth Bosch

CONSULTANTS FIND EDISON OVERLOADED CABLES LEADING TO POWER FAILURES

The consulting firm hired to investigate Commonwealth Edison Company's power failures in July and August this year, said today that poor maintenance of the electrical system and routine overloading of electric cables led to the failure of the system.

Vantage Consulting, Inc., of Wayne, Pennsylvania, conducted the investigation into the power outages, focusing, particularly, on the equipment that failed, Edison's maintenance of the system and its emergency response to the outages. Walter Drabinski, president of Vantage Consulting, told the Commission Wednesday, that Commonwealth Edison's practice of overloading distribution cables contributed to the equipment failures.

And, he warned, Edison has continued to load electric cables at higher than recommended levels, which could lead to similar breakdowns in the system in the future.

ICC Chairman Richard Mathias said in August the Commission was "most interested in finding the root causes" of the power failures. Vantage concludes that the root cause of the outages was cable failure, due to a heat-induced breakdown of insulation brought on by repeated cable overloading.

Commonwealth Edison apparently "rated the current carrying capacity of its distribution cables higher than the cable manufacturers typically recommend under similar circumstances, and then repeatedly loaded the cables in excess of its own unusually high ratings," according to the consultant's report.

The Vantage report cited poor maintenance of equipment as a contributing factor in the equipment. The report indicated, for example, that Edison failed to clean cooling fins on a transformer at the Jefferson Street substation, and did not repair and return to service the transformers temperature alarm system. Later that transformer was replaced because of problems caused by overheating.

The consultants also concluded that the company caused the failure of an important transformer in the Northwest Substation by closing a circuit breaker without fixing the cable failure that caused the breaker to open. As a result, high current flowed through the transformer into the disabled cable and the transformer was damaged.

The consultant's report also noted that Commonwealth Edison continued to use a type of 1950's vintage insulating sleeve on some cables, even though Edison knew of problems with its reliability. The insulating sleeves were found to be involved in cable joint failures which occurred in July and August last year.

As part of its report to the Commission, Vantage recommended that Edison make a number of improvements to its system, including

- ♦ reassessing cable load rating criteria, establishing new, appropriate ratings and operating the system under these constraints;

- ♦ reexamine the cable configurations, loading, and sizes for the Northwest Substation to assure that similar overloads do not occur in the future;

- ♦ institute a traceable system of communications for maintenance work;
- ♦ reassess its policies for rating cables and transformers; and
- ♦ modify communications processes and record keeping to minimize problems associated with verbal communications of equipment corrective maintenance requirements.

The cost of the Vantage investigation is estimated at $300,000, and will be paid by Commonwealth Edison. A second and third phase of the investigation, to be conducted by Liberty Consulting Group of Quentin, Pennsylvania, will examine system-wide reliability.

A final report on the system-wide reliability is expected by the end of 2000.

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June 8, 2000

LIBERTY CONSULTANTS FIND EDISON UNDERFUNDED MAINTENANCE AND REPAIR OF TRANSMISSION/DISTRIBUTION SYSTEM

Engineers for The Liberty Consulting Group told the Illinois Commerce Commission today that while Commonwealth Edison Company in general had good standards, procedures and people to carry them out, its electrical system failed in summer 1999 because the company had not spent nearly enough money on maintenance and necessary system improvements in prior years.

The Liberty Consulting Group Inc., was hired by the ICC to examine the Commonwealth Edison transmission and distribution systems, as well as the company's standards, policies, procedures and practices as they existed at the time of, and prior to Edison's 1999 power outages.

Liberty's investigation is not directed at summer 1999 outages or at Commonwealth Edison's ongoing system rehabilitation efforts, but rather at the condition of Commonwealth Edison's system and the utility's actions or inaction that set the stage for the decline in its service reliability in recent years.

ICC Chairman Richard Mathias said when the evaluation began the Commission did not know what actions Commonwealth Edison would take to fix its system or the priority of such actions. "We wanted an evaluation of what went wrong as well as a benchmark against which we could measure progress," he said.

Late last year, the Commission released a report from Vantage Consulting that detailed the circumstances of Commonwealth Edison's summer 1999 outages in Chicago and surrounding communities, and that the report is available on the Commission's web site, **http://www.icc.state.il.us**. In a related but separate effort, the Commission staff is monitoring the utility's progress toward rehabilitating its system as detailed in Edison's September 15, 1999 report.

Robert Stright, Liberty's Engagement Director, said that prior to summer 1999 power outages in the Chicago area, Commonwealth Edison Company's practice was to wait for its distribution system to fail before taking any action to repair or improve it. The consultants found that Edison cut back spending on capital improvements and regular maintenance for its transmission and distribution systems from 1992 to 1998. So strong was the utility's desire to limit spending, the consultants found, that between 1992 and 1998, Edison spent $225 million less than its cumulative budgeted capital spending for the period, even though customer load continued to grow.

In addition, the consultants found that while Edison's own substation maintenance work fell further behind schedule in 1998 and early 1999, the utility sold electrical construction and maintenance services to third parties, using its own maintenance staff. In the meantime, the utility's backlog of maintenance projects and repair work mushroomed.

In its report to the Commission Liberty said that Commonwealth Edison indicated in 1998 that it had budgeted an additional $307 million for service reliability improvements during 1999-2001, but that less than $200 million was actually aimed at improving system reliability. The consultants concluded that the remaining money was budgeted for connections to the utility's fossil fuel plants and on new connections to independent power producers' generating plants.

Liberty said that prior to summer 1999, Commonwealth Edison used a 15-year average weather adjustment (a temperature of 93 degrees) for peak-load data in its load forecasts. The result was that Commonwealth Edison's annual peak loads had a 50 percent chance of exceeding the utility's forecast. In 1995, as a result of a previous Commission investigation, Failure Analysis Associates recommended to Commonwealth Edison that it change its weather adjustment method by adjusting to 99 degrees instead of 93 degrees. The utility disagreed and made this change only after the summer of 1999. Liberty pointed out that, with the adjustment to 99 degrees, Commonwealth Edison can expect its actual peak load to exceed its forecast about once every 10 years.

The Liberty consultants made 59 recommendations, based on a greater number of findings. Among those recommendations were that Commonwealth Edison should:

- dedicate the necessary funding to maintain and improve reliability of its transmission and distribution system;
- prevent the physical condition of its distribution system from deteriorating to the point it was in the summer of 1999;
- reduce and prioritize the tremendous backlog of maintenance projects;
- justify the way it makes weather adjustments to historical peak electrical loads for its five year load forecasts;
- implement a program to install fuses on all laterals and taps in accordance with standards;
- expand the maintenance testing of cables to include all priority cables;
- de-rate transformers to allow a planning margin that will minimize overloading; and
- relieve overloading on substation transformers and cables on the basis of realistic temperature predictions.

The cost of the Liberty investigation is estimated at $1.6 million, which is to be paid by the utility.

This report is the first of a series from Liberty on Commonwealth Edison's transmission and distribution system problems. Each report will be posted to the ICC website at http://www.icc.state.il.us. A final report is expected by December, 2000.

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Executive Summary

I. Project Objective

The Liberty Consulting Group *(Liberty)* investigated Commonwealth Edison Company's *(ComEd's)* transmission, distribution, and related management systems to describe and evaluate those systems as they existed during the summer of 1999, compare ComEd's systems to good utility practices, report areas where ComEd's systems fell short of those good utility practices, and specify the actions needed to move ComEd to the higher standard. This is the first of a series of reports on the results of Liberty's investigation.

As a result of the outages that occurred in July and August of 1999, ComEd undertook many initiatives to improve its performance. The changes resulting from these initiatives were occurring during this investigation. It may be that ComEd is in the process of implementing some of the recommendations made in this report. In some cases, Liberty was aware of ComEd's current plans or actions, and mentioned them in this report. However, Liberty did not allow ComEd's current activities and plans to influence the content of this report. It was the intent of Liberty and the Illinois Commerce Commission *(Commission* or *ICC)* Staff that this report serve as the basis for a future investigation of ComEd's systems, after ComEd has had a reasonable time to bring them up to the standards of good utility practice.

The Commission stated and Liberty adopted the following goals for the project:

1. evaluate ComEd's planning, procedures, and practices used to mitigate any deficient system performance,

2. evaluate ComEd's planning for and execution of emergency response and system restoration efforts,

3. evaluate ComEd's internal and external communications related to outages and service restoration,

4. evaluate ComEd's inspection, maintenance, replacement, and upgrading of equipment and overall transmission and distribution system,

5. evaluate ComEd's system performance compared to other major metropolitan service territories, detailing significant differences and similarities in system operation, planning, and design, and

6. evaluate ComEd's organizational and management structure and the adequacy of performance measures used to evaluate personnel and system reliability.

II. Scope

Liberty conducted this investigation of ComEd's transmission and distribution systems according to the Illinois Commerce Commission's request for proposals and the subsequent contract between Liberty and the Commission. The Commission Staff had developed two lists of questions for Liberty to answer: Energy Division, Engineering Department Questions for ComEd Outage Investigation and Distribution Reliability Review and Energy Division, Engineering Department Questions for ComEd Outage Transmission Reliability Review. The Commission Staff asked that Liberty examine two previous investigation reports and determine if ComEd had implemented the recommendations they contained: Report on the Investigation of the Electric Transmission and Distribution Reliability of the Commonwealth Edison Company, by Resource Management International *(RMI)*, dated March 1992 and Investigation of Service Interruptions in the Commonwealth Edison System During the July 12-16, 1995 Heat Wave, by Failure Analysis Associates *(FaA)*, dated November 28, 1995. The Commission Staff also asked Liberty to review two October 27, 1998, ComEd management presentations to the ICC, Statement of John W. Rowe and Paul McCoy Presentation to ICC on October 27, 1998, and determine if ComEd had performed the actions detailed therein. Finally, the Commission Staff asked Liberty to review the report on the July-August 1999 outages, when completed by Vantage Consulting, and identify any leads, findings, or recommendations appropriate for inclusion in Liberty's investigation.

III. Summary of Findings

A common theme that runs through the chapters of this report is that ComEd possessed good standards, policies, procedures, and practices, and good people to carry them out, but often failed to meets its own standards or follow its own procedures because it failed to budget enough money for necessary capital improvements and maintenance. Even ComEd's failures in the areas of load forecasting and planning may be traced to a corporate desire to minimize the money spent to improve the transmission and distribution *(T&D)* system. In many aspects, ComEd was in a reactive mode of operation, often waiting for parts of it T&D systems to fail before taking any action and only attempting to improve the worst parts of its T&D systems.

This section is organized by report chapter and consists of short pieces of text taken from the body of this report to give the reader a sense of the content of each chapter. This is not a collection of Liberty's conclusions, which can be found at the end of each chapter, although the content is similar. Chapter One of the report is the introduction.

Chapter Two – T&D Organization: Liberty found that although ComEd had skilled personnel and adequate policies and procedures, its goals and objectives were dominated by cost control and failed to focus sufficiently on customer service and service reliability during the 1990s.

- Three transmission and distribution personnel reorganizations aimed at manpower and cost reduction caused inefficiencies and confusion throughout the 1990s.

- Customer satisfaction was no longer a stated ComEd goal after the 1992 reorganization.

- In 1995, two-thirds of the ComEd's management compensation incentive plan stressed cost reduction.

- The 1997 incentive goals for the T&D organization had only one quantitative goal, which was a measure of operations and maintenance expense per customer.

Chapter Three – T&D Budgeting: Liberty found that during most of the 1990s, ComEd exercised cost control and reduction policies that resulted in less than adequate funding for transmission and distribution. It is likely that a root cause of many of the service interruptions experienced by ComEd's customers in recent years related to this less than adequate funding.

- ComEd's transmission and distribution capital and operations and maintenance expenditures declined in the mid-1990s. The share of ComEd's corporate capital budget spent on transmission and distribution also declined during this period. These declines were the result of ComEd's conscious and concerted efforts to reduce costs.

- ComEd's capital spending for transmission and distribution from 1991 through 1999 was $225 million less than ComEd's cumulative budgeted amounts for that period.

- Less than $200 million of the additional $307 million in capital expenditures that ComEd announced in late 1998 in response to worsening transmission and distribution performance was actually targeted for reliability projects.

- On a per-customer basis, ComEd's operations and maintenance expenses for transmission and distribution declined from the level spent in the years 1991-1993 to and lower level in the years 1994-1997, and were below the median of a large group of comparison utilities for the entire period of 1988 through 1998.

Chapter Four – Assessment and Reporting of System Reliability Information: Liberty found that ComEd did not effectively use reliability information to help provide better service to its customers.

- Of the 46,000 service interruptions that ComEd reported to the Commission for calendar year 1998, ComEd classified 8,418 of the interruptions, more than 18 percent, as having an "Unknown" origin. Once ComEd closed an outage report, it made no attempt to change the cause code. Therefore, ComEd did not analyze nearly one in five of the interruptions experienced by its customers after the restoration activities.

- In 1990, an audit completed for the ICC recommended that ComEd should continue to develop customer-based outage reporting and set milestones for achieving results and measuring progress against these results. In 1995, another audit completed for the ICC recommended that ComEd should complete the software to compute customer-based reliability indices. ComEd's 1994, 1995, 1996, and 1997 Reliability Performance Reports to the ICC noted that the new computer system designed to track individual customer interruptions was in the process of being completed. However, as of June 1999, ComEd's system still required manual intervention to assess the number of customers affected by some outages.

- The timing of many of ComEd's initiatives to improve its assessment and use of reliability information coincided with a year of particularly poor performance and increased regulatory scrutiny and requirements. The impetus to improve did not come from within ComEd, but rather was from external factors. The problem with that type of motivation for change is that it may not be deep-seated and long-lasting.

- Even when serious problems became apparent, ComEd did not demonstrate that it had implemented effective programs to solve them. ComEd did not take reasonable steps to ensure that it collected consistent and accurate reliability information. ComEd did little, if any, outage follow-up investigative work. The company was not timely in its development of the interruption reporting system that was widely recognized as necessary for effectively using reliability information. ComEd's organization was not conducive to good input from reliability engineers to planning and maintenance. Without the information and without the communications, there is little reason to believe that reliability influenced ComEd's system decisions.

Chapter Five – Distribution System Planning: Liberty found that while ComEd's organization of the planning function was reasonable, ComEd did not use reasonable, conservative assumptions in making peak electrical load estimates and did not adequately reinforce its distribution system.

- ComEd used average weather conditions to plan for distribution system loads and therefore had a 50 percent chance that the forecasted loads would be exceeded. ComEd used weather conditions that equated to an average temperature of about 93°F as its base peak-day planning temperature. However, Liberty learned that since the year 1928 the median daily peak temperature during July has been 96 degrees. The highest five-day average of daily maximum temperatures during the 1928-1999 period was 99.8 degrees, nearly seven degrees hotter than the temperature ComEd used for planning purposes.

- After the July 1999 events, ComEd changed its base peak-day planning weather conditions from the 50th to the 90th percentile, or about 99 degrees. However, because electric energy has become a life-essential service, designing the electric system to sustain loads that may be imposed on it, even just occasionally, is a necessity. The maximum temperature recorded at Chicago-Midway was 107 degrees in June of 1934. The second highest day on record was 106 degrees in July 1995 followed by 104 degrees in June 1988 and July 1999. In fact, a temperature of 104 degrees or more has been experienced in 5 of the 73 years recorded. Simplistically, this suggests a 1 in 15 year probability that ComEd's electric system will be subjected to a temperature of 104 degrees or more.

- When planning main feeders, ComEd's planners attempted to include feeder-to-feeder ties to provide alternate feed possibilities for both emergency and normal operational switching. ComEd did not give its planners defined reliability criteria for determining capacity, frequency, or timing of the ties between feeders. Instead, ComEd left those criteria to the discretion of each planner.

- The load on many of ComEd's feeders was more than 110 percent of capacity. During the July 1999 events, ComEd could not switch some customer loads from damaged feeders to feeders that were not affected by the outages because those unaffected feeders were already overloaded.

- The combination of the 110 percent equipment overload standard with the average peak-day weather adjustment increased significantly the likelihood of system failures.

- ComEd operated some of its equipment above normal thermal limits. This policy led to failures sooner than would otherwise be the case. To manage these potential events effectively, it is necessary for ComEd to monitor, record, and accumulate the excesses, or loss-of-life events on major equipment such as large transformers and main feeder elements. Liberty found that ComEd did not formally monitor and document its equipment for loss-of-life events.

- ComEd allowed the load on its transformers and feeders to increase considerably over the past ten years. To the extent that increased load increased the frequency or duration of events that caused ComEd's equipment to operate above normal ratings, the probability of failures increased correspondingly.

Chapter Six – Distribution System Design: Liberty found that ComEd's distribution design standards and design review process were consistent with good engineering and utility practices. ComEd's distribution design provided the necessary qualities for the provision of durable and reliable service.

Chapter Seven – Distribution System Protection: Liberty found that ComEd performed reasonably well in most aspects of distribution system protection. However, ComEd's testing and maintenance of protective relays was inadequate, and ComEd did not always follow its distribution system protection standards.

- In 1995 a task force of ComEd employees made five recommendations for changes to ComEd's system protection. Liberty agreed with three of the task force's recommendations, but ComEd did not fully implement any of them.

- ComEd's distribution protection practices within substations were reasonable, but not so for ComEd's practices outside substations. ComEd's Distribution Protection Standards required fusing of lateral taps off main distribution feeders, however, ComEd did not follow its standard and did not fuse these taps. Unfused taps decreased the reliability of ComEd's distribution system.

- ComEd's distribution protection standards contained requirements to install line reclosers on distribution feeders that were too long to allow substation relays to detect faults near the end of the feeder. ComEd did not consistently apply this standard. Doing so would have improved service reliability.

- Before 1998, ComEd's distribution relay testing interval was 10 years for major maintenance. In 1998, ComEd lengthened the interval to 14 years and to 21 years if a relay operated automatically during the period. Liberty judges 14 years between significant relay tests to be too long. Most utilities test their relays on a one-year to five-year interval. When a relay fails to operate properly, damage to the distribution system may increase and interruptions of service to customers may lengthen.

- ComEd operated many of its distribution substation transformers connected in parallel. Parallel operation results in much larger fault currents on substation buses and on distribution feeders when a fault occurs. In the past, ComEd has attempted to limit fault current due to single line-to-ground faults by installing neutral inductors in its substations, but ComEd recently decided to stop installing neutral inductors. The magnitude of fault current can affect the amount of damage done to distribution equipment and cables. Parallel operation of distribution substation transformers could make cable basement fires more likely.

Chapter Eight – T&D Lightning Protection: Liberty found that lightning-related equipment outages affected ComEd's distribution system reliability significantly. While ComEd provided good lightning protection for parts of its transmission and distribution systems, there are improvements that ComEd should make. For example, and contrary to good utility practices, ComEd did not provide direct-stroke lightning protection on all of its substations.

- Lightning accounted for about half of the weather-related interruptions experienced by ComEd's customers in 1998, a year that ComEd said included an unprecedented ice storm in March and an extreme wind storm with hurricane force winds in November. Without those two unusual storms, the percentage of interruptions caused by lightning would have been even higher.

- The average duration of interruptions caused by lightning in 1998 over six hours while the average duration of interruptions for all causes was about four and one-half hours.

- ComEd constructed its 34kV lines with overhead static wires for lightning protection until recently. When ComEd built its Marengo TSS123 to Harvard SS318 line, it replaced the overhead static wires with lightning arresters. This change may not have been good for reliability. Between May 1998 and July 1999, the line experienced 22 outages, 18 of which were caused by lightning. This is a significant number of lightning outages for a 34kV line or any other line.

- ComEd did not use shield wires to provide direct-stroke lightning protection to some 138kV substations and all substations at voltages below 138kV. Direct-stroke protection of substations is almost a universal utility practice, which ComEd did not meet.

- ComEd did not provide lightning arrester protection at terminals of underground transmission cables.

Chapter Nine – Distribution System Operations and Maintenance: Liberty found that although ComEd's Distribution Dispatch Center and the dispatchers' practices were consistent with most good utility practices, there were factors that limited the ability of the dispatchers to fully monitor and control distribution systems. ComEd's distribution system lacked the capacity to serve customers' loads during extreme conditions and so system operations could not cope with simultaneous problems. Liberty also found some deficiencies in ComEd's distribution maintenance organization and performance, including a very large backlog of maintenance actions, and therefore some aspects of ComEd's maintenance practices were not consistent with good utility practices.

- ComEd's planning and upgrade practices created some challenges for the operations group. Since ComEd allowed its planned equipment and feeder loading to go up to and in excess of 100 percent of ComEd's ratings, and with several load relief projects behind schedule, the operations group was occasionally forced (for example when equipment failed) to decide whether to overload equipment, or shed load.

- ComEd provided its dispatchers with summer load data and lists of potential summer problem areas too late for the dispatchers to be properly informed of system loading conditions.

- ComEd did not monitor transformer and cable temperatures to determine if equipment required revised ratings and reduced loadings.

- Liberty found that ComEd's emergency dispatching procedures did not meet good utility practice because of repair procedure delays and a lack of priority for restoring service to customers when unusual conditions existed or repairs took longer than expected. ComEd did not have procedures that placed a priority on picking up interrupted customers using portable generators or transformers. Crew callout procedures caused average interruption times to go from about two hours to about eight hours if a repair crew was needed.

- ComEd's maintenance expenses per customer declined after 1992 and did not return to the 1992 level until 1998, when ComEd experienced an unusual number of storms.

- Liberty found several shortcomings in ComEd's distribution system preventive maintenance practices in the areas of content, diagnostic testing, frequency, and performance and concluded that it did not meet good utility practices.

- In the summer of 1999, ComEd had a backlog of 79,000 maintenance items, many of which exceeded ComEd's policy for completing maintenance actions in at least twelve months. At the same time, ComEd was using its distribution personnel to perform work on equipment and facilities that did not belong to ComEd.

- In a 1992 report to the ICC, RMI recommended that ComEd develop more detailed plans and budgets to prioritize maintenance work and create a system-wide program for tracking backlogs. RMI warned that without such efforts, a "very large backlog of work" would develop. RMI also recommended that ComEd analyze maintenance programs for their expected effect on reliability and determine the costs necessary so that these programs could be prioritized. Liberty found that ComEd's efforts to meet these recommendations were ineffective or nonexistent.

- ComEd was inspecting poles on an eight-year cycle. The number of backlogged maintenance items shows that an eight-year cycle is too long.

Chapter Ten – Distribution System Conditions: Liberty found that ComEd built its distribution system using engineering, construction, and material standards consistent with practices of other utilities. However, ComEd did not have programs in place to identify and replace or refurbish equipment that had aged and had been overloaded such that its expected life had been reduced. Liberty also found that ComEd had allowed its distribution system to become heavily loaded and had not properly maintained the physical condition of distribution equipment.

- Age should not be the only factor for determining when a cable should be replaced. However, if a utility has not kept track of conditions like overloads and faults, then there comes a time when good utility practice requires a utility to replace cables (and other equipment) or provide back-up capacity so that system reliability will not suffer. Liberty assessed the age of circuits at the Northwest(1) substation and found that twelve of the circuits were over 60 years old and seven of the circuits were over 70 years old. Without any other information available, ComEd should have either replaced many of these circuits or substantially reduced the load and dependence on them long before the summer of 1999.

- ComEd had an engineering standard for determining when distribution transformers were overloaded. However, ComEd's data indicated that it had over 10,000 distribution transformers with loads in excess of 150 percent of their nameplate rating. In fact, ComEd's data showed 431 distribution transformers with loads in excess of 1,000 percent of nameplate rating. Since loads of this size would cause catastrophic failure of the transformers, and since ComEd's data did not indicate failures in this manner or in these numbers, Liberty concluded that ComEd's transformer load data was not accurate. It was apparent that ComEd did not have the reliable data it needed to follow its standard.

- ComEd consistently projected loads on distribution circuits to be above 90 percent of their normal rating. Loading circuits to this level did not allow ComEd to transfer load during system emergencies without overloading the circuits. For example, Liberty found 18 circuits in Chicago that were overloaded by up to 156 percent of their emergency rating in 1999.

- Following the July and August outages in 1999, ComEd inspected 626 of its 4,472 distribution circuits and found 6,460 problems. This inspection showed that ComEd's distribution system was not in a good state of repair and ComEd's prior inspections had failed to assess the physical condition of the distribution system.

Chapter Eleven – Substations: Liberty found that while most aspects of ComEd's substation designs were good, substation maintenance and the organizational structure responsible for maintaining and testing substation equipment was not consistent with good utility practices.

- While the construction skills of ComEd's substation mechanics were impressive, their maintenance skills were not. Liberty observed ComEd mechanics performing 12kV circuit breaker maintenance at the Kingsbury-Ohio substation. The mechanics did not have a copy of the work procedures, did not perform any tests to verify the electrical integrity of the breaker, used an improper lubricant, and exposed spare circuit breakers to damp outdoor air. This lack of following good utility practice indicated either the need for additional training or better technical supervision.

- ComEd did not have substation test crews specially trained and equipped to perform the more complicated acceptance and maintenance tests required by the work procedures. The number of test sets (one of each) and qualified shop electricians (2-3 for each test set) to operate the test sets were insufficient. A nearby utility about one-half the size of ComEd had several substation test crews, power-factor insulation test sets, and circuit breaker motion analyzers.

- In July 1999, ComEd employed 509 substation mechanics. ComEd sometimes used these mechanics for non-ComEd projects. During the period of January 1998 to August 1999, ComEd pursued the sale of electrical construction and maintenance services, and provided engineering and skilled labor to perform construction, maintenance, or repair work for about 200 non-ComEd projects. Of these, about 120 projects used ComEd linemen and substation mechanics. While some of these projects were important to the reliable operation of ComEd's system, the practice of using ComEd's mechanics and electricians for outside work, during a period when ComEd's maintenance backlog was significant, was not consistent with good utility practices.

- ComEd used contractors to perform a few specialized maintenance procedures in substations, but did not use contractors to perform any other substation maintenance. Not using quality substation maintenance contractors, when the substation maintenance was significantly backlogged, was not consistent with good utility practices.

- According to ComEd's study, if the summer peak temperatures in 2000 match those experienced in 1999, the loading on some transformers and feeders will exceed ComEd's normal rating if no reinforcements are accomplished. This expected and very possible loading is the result of ComEd's inadequate planning.

- ComEd rated its transmission substation and distribution substation transformers to be operated at 128 percent of nameplate rating for normal summer loads, 155 percent of nameplate rating for ten days (producing an 85°C rise for the top oil temperature) during an emergency, and 170 percent for two hours to allow for switching. Other utilities also have a practice of allowing occasional overloading that results in reduced transformer life. However, ComEd could not provide a convincing justification for the ratings it chose to use. ComEd's transformer ratings were slightly excessive when compared to the guidelines contained in IEEE standards.

- ComEd was not able to complete some scheduled substation upgrades, such as at LaSalle and Northwest Substations, in timely fashion. The delays in completing substation upgrade work jeopardized reliable electric service.

- The ComEd substation maintenance programs lacked sufficient budgeting, supervision, or manpower to complete maintenance on a timely basis. In August 1999, ComEd had a backlog of about 5,200 substation corrective maintenance tasks and 20,000 preventive maintenance tasks. Such backlogs are not consistent with good utility practices.

- Although ComEd's maintenance program manuals indicated that tests were to be performed on substation equipment, Liberty found no evidence to show that the tests were actually performed.

- ComEd decreased substation maintenance expenditures from about $45 million in 1991 to about $15 million in 1998. From January 1988 to July 1999, transmission substation and distribution substation circuit breakers failed to operate at a rate of about 75 per year. Transformer failures in transmission substations and distribution substations totaled 85 from 1992 to 1999. This large number of failures was excessive.

IV. Summary of Recommendations

At the end of each chapter of this report are recommendations relating to the subject matter of the chapter. This section is a collection of those recommendations. Each recommendation is identified with a number that shows both the chapter from which it is taken and the recommendation number within the chapter.

Two-1 Expedite the transition from the interim organization to a permanent T&D Operations organization. Some organizational improvements should be made.

Three-1 ComEd should dedicate the necessary funds to maintain and improve the reliability of its T&D systems.

Four-1 ComEd should demonstrate, and the ICC may choose to independently confirm, that the company is effectively using reliability information.

Five-1 ComEd should justify the way it adjusts the historical peak electrical loads for 5-year forecast.

Five-2 ComEd should implement a "First Contingency" criterion for its distribution feeder design process.

Five-3 ComEd should develop a "Remaining Life" data base and review process that includes recording of overloading events, replacement plans, and a double contingency design under certain circumstances.

Five-4 ComEd should establish an annual, formalized, objective review of the distribution load forecast processes that quantifies the assumptions and the accuracy of the forecast for each projected year.

Five-5 ComEd should formalize distribution planning guidelines for determining when load relief should begin for circuits and transformers. In addition, ComEd should develop a formalized procedure for producing its annual five-year load forecast and budget review.

Five-6 ComEd should move from its SAS-based feeder forecast program to a state-of-the-art forecast computer environment.

Six-1	ComEd should review or correct several specific items in its Engineering Standard Practices and cable rating program.
Six-2	ComEd should review and correct as necessary its Load Ratings Book.
Seven-1	ComEd should reduce the testing interval for distribution system protection relays and develop a program to catch up on the backlog of relay testing that has developed.
Seven-2	ComEd should implement a program to install fuses on all laterals and taps in accordance with the ComEd Standards.
Seven-3	ComEd should develop a formalized procedure to replace old and obsolete feeder protection relays with microprocessor-based relays.
Seven-4	ComEd should review its system and install reclosers on feeder taps in accordance with its standards on the basis of load and at the midpoint on lines that have a length of 5 miles or more.
Seven-5	ComEd should evaluate the application of neutral grounding inductors on large distribution power transformers and apply neutral inductors on each 12kV distribution power transformer rated 40 MVA and above.
Seven-6	ComEd should provide the regional Technical Investigations Superintendents with a common technical manager.
Seven-7	ComEd should replace incandescent indicating lamps with LED (light emitting diode) type lamps.
Eight-1	ComEd should use to its full potential the available technology that locates lightning strokes in relation to its T&D system.
Eight-2	ComEd should discontinue the use its new 34 kV line lightning protection design until it can explain the high outage rate on the 34 kV line in the Northwestern Region.
Eight-3	ComEd should install shielding in all new substations to provide direct-stroke lightning protection. Furthermore, ComEd should review all existing substations and develop a program to provide direct-stroke protection where economically feasible.
Eight-4	ComEd should investigate its practice of not grounding the shield wires of all transmission lines to the substation ground grids.

Eight-5 ComEd should provide lightning protection for underground transmission lines.

Eight-6 ComEd should specify lightning arresters on the 12 kV and 34 kV secondary windings for all new power distribution transformers .

Nine-1 The distribution planning group should present the annual summer loading data to the distribution dispatchers by March 31 or earlier.

Nine-2 ComEd should include in their restoration procedures priority to installing temporary connections, portable generators, or portable transformers during repair work when loads cannot be picked up by normal switching.

Nine-3 ComEd's dispatchers should be monitoring, via SCADA and PI-historian software, transformer and cable temperatures, at least where over-temperature conditions may exist.

Nine-4 ComEd should plan to install remote monitoring of network protectors.

Nine-5 ComEd should prepare an Emergency Distribution Load Shedding Plan indicating clearly defined procedures to determine when to shed load, what load to shed, and who to notify.

Nine-6 ComEd should have procedures that (1) allow troublemen and operators to perform repairs more often, and (2) provide quick access to repair crews.

Nine-7 ComEd should accelerate the implementation of the digital mapping (CE*GIS) of their equipment and have it integrated into the interruption location software.

Nine-8 The distribution construction and maintenance organization should be separated from the substation group.

Nine-9 ComEd should reduce and prioritize the maintenance backlog.

Nine-10 ComEd should integrate the various databases used to track distribution equipment, construction, and maintenance.

Nine-11 ComEd should increase the frequency of the pole inspection program, which includes 25 specific items to inspect and other items to upgrade, to every four years.

Nine-12	ComEd should expand the maintenance testing of cables to include all priority cables.
Nine-13	ComEd should expand the distribution equipment inspection program.
Ten-1	ComEd should develop proactive programs to track the age, loading, and physical condition of its distribution system so that repairs, refurbishment, and replacements can take place before system failures occur.
Ten-2	ComEd must not allow the physical condition of its distribution system to deteriorate to a condition like that which was discovered in the Fall of 1999.
Ten-3	ComEd should improve the accuracy of the system used to track distribution system transformer loading.
Eleven-1	ComEd should improve the organization responsible for substation construction and maintenance.
Eleven-2	ComEd should promote accountability and responsibility for substation maintenance.
Eleven- 3	ComEd should review and upgrade as necessary the substation training programs for substation mechanics.
Eleven- 4	ComEd should only perform work on non-ComEd equipment when that work is critical to the reliability of ComEd's system.
Eleven-5	ComEd should use outside contractors for substation maintenance to reduce the maintenance backlog.
Eleven-6	ComEd should complete upgrade work that is planned.
Eleven-7	ComEd should improve the RELAP program.
Eleven-8	ComEd should de-rate transformers to allow a planning margin that will minimize overloading of transformers.
Eleven-9	ComEd should use more conservative weather adjustments in planning for loading on substations.
Eleven-10	ComEd should determine acceptable transformer loss-of-life.

Eleven-11 ComEd should have a formal, technical review made of its transformer loading criteria.

Eleven-12 ComEd should take action to relieve overloading on TSS and TDC transformers and cables on the basis of realistic temperature predictions.

Eleven-13 ComEd should maintain thermal load records for substation transformers.

Eleven-14 ComEd should conduct tests whenever a substation transformer experiences a temperature alarm.

Eleven-15 ComEd should intensify testing and maintenance for transformers that may be heavily loaded.

Eleven-16 ComEd should reduce the substation maintenance backlog.

Eleven-17 ComEd should establish substation test crews.

Eleven-18 ComEd should consider having Substation Maintenance Programs reviewed by others.

Eleven-19 ComEd should evaluate all available cable testing procedures.

July 19, 2000

LIBERTY CONSULTANTS CITE EDISON'S TREE TRIMMING PRACTICES, LACK OF MANPOWER, IN POWER OUTAGES

The Liberty Consulting Group, which is examining Commonwealth Edison Company's electrical distribution and transmission systems following several major power outages in 1999, today released its second report. The ICC hired Liberty Consulting to review the Commonwealth Edison transmission and distribution systems, as well as the company's standards, policies, procedures and practices at the time of and prior to Edison's 1999 power outages.

Liberty's second report found that, among other shortcomings, the utility's tree trimming programs were inadequate, poorly planned and understaffed. The report states that many of the interruptions of electric service experienced by Commonwealth Edison's customers were caused by trees contacting the utility's distribution facilities and that funding for tree trimming was inadequate; management oversight and tracking of tree trimming progress, inadequate; and tree trimming standards insufficient to assure distribution system reliability. Liberty also concluded that Commonwealth Edison had failed to adopt a recommendation for increased tree trimming from a 1992 audit conducted by Resource Management International for the ICC.

The Liberty consultants' conclusion was that while the utility may have had generally good standards, procedures and people to carry them out, its electrical system failed because the company had not spent nearly enough money on maintenance and necessary system improvements in prior years. Liberty found that Commonwealth Edison set its distribution and transmission staffing levels without reasonable plans or studies regarding the work necessary to assure reliable service. In 1991, the company expected staffing levels to increase during the early and middle 1990s, but staffing during those years, instead, dropped.

Liberty also determined that Commonwealth Edison did not perform the level of distribution system construction, after 1992, that would have been consistent with the age of the utility's equipment and the growth of electric load on the system.
The Liberty consultants added nine new recommendations in their second report to the 59 recommendations contained in their first report. The nine new recommendations say that Commonwealth Edison should:

- develop and implement a comprehensive manpower planning program;
- develop a formal management succession plan;
- evaluate the positions within its organization that have high or low spans of control;
- formalize its tree trimming standards;
- ensure adequate annual funding of their vegetative management program;
- take a more aggressive approach to tree trimming management;

- make a special report on tree trimming each year to the ICC;
- increase its distribution construction to a level necessary to keep up with the distribution conditions and load growth; and
- make several enhancements to its construction management practices.

In its first report to the Commission, released in early June, Liberty evaluated Commonwealth Edison’s electric distribution system. This second report concludes Liberty’s investigation of the distribution system. Meanwhile, Liberty is well into its investigation of the transmission system and will provide two reports covering the transmission system to the Commission later this year. Both of the completed Liberty Consulting reports are posted on the ICC Internet web site, **http://www.icc.state.il.us.** Printed copies are also available from the Commission.

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ILLINOIS
COMMERCE COMMISSION

ANNUAL REPORT
ON ELECTRICITY, GAS, WATER
AND SEWER UTILITIES

2000

January 31, 2001

The Honorable George Ryan
Governor, State of Illinois
State Capitol, Springfield, Illinois

Chairman and Members, Joint Committee on Legislative Support Service
313 State Capitol, Springfield, Illinois

Dear Governor, Chairman and Members of the Joint Committee:

We are pleased to submit to you the Commission's 2000 Annual Report on Electricity, Gas, Water, and Sewer Utilities. This Report covers the period of January 1, 2000, through December 31, 2000.

The Annual Report is submitted in compliance with the Public Utilities Act and specifically addresses the items cited in Section 4-304 of that Act.

Sincerely,

Richard L. Mathias, Chairman

Ruth K. Kretschmer, Commissioner

Terry S. Harvill, Commissioner

Edward C. Hurley, Commissioner

Mary Frances Squires, Commissioner

Independent System Operator

A number of Illinois electric utilities, including Commonwealth Edison, Illinois Power and Ameren CIPS have announced plans to leave the proposed Midwest Independent System Operator (MISO) to join Alliance Regional Transmission Operator. The Commission initially filed comments with the Federal Energy Regulatory Commission urging it to reject IP's plan to leave the MISO because too little was known about the structure and pricing of electricity under the RTO. The Michigan Public Utility Commission joined Illinois in its protest. At the end of 2000 the FERC had not ruled on IP's proposal to withdraw from the MISO.

Plant Sales/Utility Mergers

In April, Interstate Power and Interstate Power and Light Company filed a joint application for approval of merger and reorganization. The surviving corporation will be renamed Interstate Power and Light Company.

AmerenUE fled petitions for the transfer of all of its Illinois electric facilities and businesses as well as its Illinois gas facilities to AmerenCIPS.

Commonwealth Edison provided the Commission with information about its plan to transfer its office assets and business to PECO. It also spun off its nuclear generating plants to an affiliate, Exelon. Edison petitioned the Commission for permission to revise its decommissioning expense adjustment rider, in conjunction with the proposed transfer to the unregulated affiliate.

Decommissioning

The Commission cut Commonwealth Edison Company's request for speedier collection of decommissioning funds from $120.9 million per year for six years to $73 million a year for four years. The Commission allowed collection of decommissioning funds in the fifth and sixth years but ordered that it would be a percentage of the $73 million based upon the supply of power Edison purchases from the new owners of its nuclear generation stations.

Electric Reliability

The Liberty Consulting Group, hired by the Commission to examine Commonwealth Edison Company's transmission and distribution systems, as well as the company's standards, policies, procedures and practices at and prior to the 1999 power outages, issued three reports over the course of the year. Engineers looking at the condition of the system reported that while the utility had generally good standards, procedures and people to carry them out, its electrical system failed in summer 1999 because the company had not spent nearly enough money on maintenance and necessary system improvements in prior years. The consulting firm also found that Edison's tree trimming programs were inadequate and power failures occurred when trees contacted power lines. In a third report, Liberty noted that while the utility's transmission system performed reliably and did not suffer the same problems as the distribution system in the late 1990s, it could have because Edison had allowed it to deteriorate.

In an unrelated case the Commission also ordered Central Illinois Light Company to begin immediately to trim trees and other vegetation away from power lines. A staff inspection and reliability reports filed by the utility, showed an unusual number of power outages related to tree limbs contacting electrical wires.

Late in the year, Illinois Power Company became the first utility in the state to file a formal proposal for a vegetation management tariff. Early in 2001, the Commission suspended the proposed tariff pending further investigation.

ENERGY ISSUES: GAS

Natural Gas Choice Program

Nicor Gas filed a request with the Commission seeking permission to expand its Customer Select program, a voluntary program which would offer customers a choice of natural gas suppliers beginning March 1, 2001. The Commission initiated an investigation into Nicor's Customer Select pilot program in an effort to determine what if any competition has developed to date and if the program should be expanded to include all customers.

Mercury Spills

Peoples Gas Light & Coke Company
AmerenUE

These eight utilities comprise over 95 percent of the regulated utility service sales to residential customers in Illinois.

The companies have provided such information as a three year history of the total number of estimated bills broken down by customer class, time of year, geographic location, customer group, and frequency of consecutively estimated bills; the reasons for estimated billing; the costs of relocating and reading meters; the methods or formulas used for establishing the amounts of estimated bills; and the programs or instruments used to minimize the frequency of estimated bills. An analysis of the data received has been conducted by Commission staff.

Section 8-403: Cogeneration/Small Power Production

Section 8-403 states that the Commission shall conduct a study to encourage the full and economical utilization of cogeneration and small power production. In addition to the independent power generation aspect of the study, the Commission is also required to examine the wheeling of electricity between governmental agencies.

This study was completed in 1987. No activities were required in 2000.

Section 8-405.1: Feasibility of Wheeling in Illinois

Section 8-405.1 directs the Commission, in cooperation with the Illinois Department of Energy and Natural Resources, to investigate the major economic and legal issues surrounding the wheeling of electricity in Illinois and to report the results of its investigation to the General Assembly. In December 1987, the Commission submitted the report titled *Electric Wheeling in Illinois* to the General Assembly.

Section 9-202: Temporary Rate Increase

On October 1, 1987, 83 Ill. Adm. Code 330 became effective. Among other things, Commission rules set the necessary conditions for a temporary rate increase and provided for refunds with interest should the temporary rate increase granted exceed the permanent rate increase granted.

Section 9-214: Study of CWIP

The study was completed and was sent to the General Assembly on December 29, 1988. Please see the Commission’s 1992 annual report, page 56, for details.

Section 9-216: Cancellation Costs

There are no plants under construction nor any requests for authority to construct new plants pending before the Commission and given that there is no due date for either the initiation or completion of this rulemaking, the Commission will initiate rulemaking as soon as practical, given the Commission's current workload and resources.

Commonwealth Edison Outage Investigation

In late July and early August 1999, Commonwealth Edison Company experienced six large outages as a result of failed distribution equipment. As a result of these outages the Commission opened an investigation into ComEd's transmission and distribution system reliability. Vantage Consulting completed the first phase of this investigation in late 1999.

Liberty Consulting has worked throughout the year 2000 to complete the second and third phases of the investigation, which looked specifically at the planning, design, construction, maintenance, and operation of ComEd's transmission and distribution systems. In completing Stages II and III of the investigation, Liberty Consulting prepared, and the ICC released four reports that detail 92 recommendations for improvement. Liberty Consulting found that ComEd possessed good standards, policies, procedures, and practices, and good people to carry them out, but often failed to meets its own standards or follow its own procedures because it failed to budget enough money for necessary capital improvements and maintenance. Liberty Consulting also found that, in many aspects, ComEd was in a reactive mode of operation, often waiting for parts of it T&D systems to fail before taking any action and only attempting to improve the worst parts of its T&D systems.

In conjunction with these investigations, Commission staff members have been assigned to observe and monitor the subsequent "Rehab" programs instituted by ComEd and report on the company's efforts to re-establish the reliability of ComEd's transmission and distribution system.

Mercury Cleanup in Northern Illinois

In September, 2000, the Attorney General, joined by Cook and DuPage County, filed a lawsuit against NICOR and two of its contractors to compel a swift and effective cleanup of the mercury contamination caused by the past removal of mercury containing regulators within the homes of NICOR's residential customers. In addition to the lawsuit, the AG's office also formed a task force to monitor NICOR's mercury cleanup activities. The Commission took part in the task force and provided assistance in reviewing the plans and other documentation associated the cleanup of the spilled mercury.

It was ultimately discovered that in addition to the mercury containing regulators, NICOR also had contamination problems due to mercury containing equipment used at the sites of larger customers and junkyards within NICOR's service territory. A similar, but smaller, contamination problem was also discovered for Peoples Gas and North Shore. Finally, a review of all Illinois natural gas providers located a limited number of mercury containing regulators being used by AmerenCIPS and Illinois Power.

ECONOMIC DEVELOPMENT PROGRAM

The Commission's economic development activities as directly related to the Illinois Public Utilities Act (PUA) are coordinated by the Financial Analysis Division (FAD). A summary of the program since its inception may be found in the 1996 and previous Commission annual reports.

The Commission coordinates its economic development activities with other state agencies, including the Department of Commerce and Community Affairs. Commission staff represent the Commission on inter-agency task forces that relate to the Commission's economic development activities. Individual economic development project proposals are reviewed in conjunction with appropriate staff from utilities, state and local government, and private businesses. Staff comments on tariff and/or rate filings by utilities and testimony in rate case proceedings serve to further articulate Commission policies in the area of economic development.

As implementation of customer choice continues, Commission rulemakings and decisions in the following areas will be assessed on an ongoing basis to evaluate impacts on economic development:

- requirements for alternative electric suppliers
- delivery services tariffs
- neutral fact finder process
- consumer education materials
- distributed resources
- real-time pricing

A Blueprint for Change

Executive Summary for the Investigation Report By Commonwealth Edison To the Illinois Commerce Commission Illinois Public Officials And the Customers of Commonwealth Edison

September 15, 1999

With the publication of the attached Reports, ComEd Chairman John Rowe is announcing today that ComEd has completed a comprehensive investigation into the outages of July and August and the integrity of the entire system. The Investigation Report maps out the specific events, details the recent improvements achieved through round-the-clock inspection, repair and replacement activities, and offers a comprehensive blueprint and preliminary timetable for the steps necessary to ensure that ComEd's service meets or exceeds industry standards.

Completed in a one month, 24-hour-a-day effort, consisting of hundreds of pages of analysis, charts, diagrams and photographs, and central to the $20 million ComEd emergency response effort that was launched in August, industry observers described the Report, the investigation and the ComEd response as "unprecedented" in the history of publicly-owned utilities.

The major findings reveal serious issues in the transmission and distribution system, especially in the areas of system maintenance, planning and design. The intensive investigation was primarily designed as a comprehensive diagnosis concerning the health of the system. In medical terms, the Report concludes that ComEd's transmission and distribution (T&D) system is in serious, but stable condition, and that the overall prognosis is good. Mr. Rowe described the results as "sobering, but essential." "For the first time, we have a clear and complete picture of what and where the problems are," he said. He added: "We also have a clear idea of exactly what needs to be done, and when."

Along with the Report, the company announced a plan today it described as a "two-year recovery program", aimed at bringing service reliability up to or beyond industry norms. As elements in the prioritized action plan, ComEd pledged accelerated and ongoing efforts to address the issues identified by the investigation.

To address the problems related to system inspection and maintenance, ComEd has already launched a 24 hour/7 days a week campaign to repair, replace or upgrade major equipment such as transmission lines, substations, feeder cables and other components. Priority repairs and upgrades will be competed before the start of summer 2000.

To address the T&D system design problems, which stem in part from the sometimes sporadic evolution of the system since the 1930's, ComEd will within 90 days complete a comprehensive System Optimization Study that is intended to map out the changes needed to re-tool the system for service in the next century.

Over the past twelve months, ComEd has been working with the Illinois Commerce Commission (ICC), the City, the Legislature, public interest advocates and others to improve its distribution system in the City of Chicago, in the suburbs and in rural areas.

In October 1998, in response to the extraordinary level of storm-related service interruptions experienced that year and a series of inquiries by the ICC and the Attorney General, ComEd accelerated its tree trimming program (fallen limbs are responsible for approximately 17% of service interruptions) and increased its three-year construction budget by $300 million. ComEd agreed to additional commitments in a May 1999 settlement with the City, bringing the total amount of committed reliability-related improvements in the City to $1.1 billion.

Finally, in discussions with the Legislature, ComEd committed to an additional $2 billion in improvements to the system outside the City over the next five years.

These initiatives demonstrated a commitment by ComEd and the corresponding public officials to improving the T&D system based on the information available at the time.

However, the dramatic events in Chicago over the last 45 days, and the results of the equally dramatic ComEd response, have convinced the company, as well as many customers and public officials, that ComEd's management of its distribution business requires truly radical change. ComEd must:

- **Find the problems in the design and maintenance of the entire system;**
- **Face the problems with clear management accountability; and**
- **Fix the problems so customers across the system receive service which meets and exceeds industry norms.**

ComEd needs a performance revolution in its transmission and distribution system to match the performance revolution it has begun in its nuclear business. This Report sets definite goals and a definite timetable for these radical changes.

Over the past six weeks, ComEd has spent more than $20 million on inspection, investigation, analysis and repair of the T&D system. Looking at the overall construction, operations and maintenance budget, ComEd expects to continue this level of effort, spending $100 million more than originally budgeted over the remainder of the year, and a total of more than $1.5 billion over the next two years. By year-end ComEd will present, to the ICC, the City and others, an enforceable plan detailing what ComEd will spend, where it will be spent, and when the projects will be completed. As part of that plan, ComEd will provide supporting documentation demonstrating the benefits of its proposed spending. ComEd intends to be held accountable for any future failures to get the work done on schedule.

In the end, however, we know that our customers will not judge us on the basis of how much we have spent or how many projects we have completed. Our customers – and the ICC and the City of Chicago – will judge us by *whether we have improved our ability to deliver power in a reliable fashion*.

ComEd's Response to the ICC August 20 Request

As a procedural matter, the attached Investigation Report responds to specific requests in the August 20, 1999 ICC letter to ComEd Chairman John W. Rowe. But moving beyond the specific requests in the August 20 letter, the attached Report is also intended to present the ICC, other government officials and ComEd's customers and stakeholders with a complete, clear snapshot of where ComEd is today. To that end, the Investigation Report provides a comprehensive account of ComEd's investigation and response concerning the service interruptions of July and August in Chicago. It also looks beyond the summer outages and charts a far-reaching course for ComEd's future and for improving performance and reliability for its customers.

In addition, as a companion piece to the Investigation Report, ComEd is releasing under separate cover today the first scheduled Implementation Report under the May 1999 Settlement Agreement with the City of Chicago (Implementation Report), as requested by Mayor Daley in his August 14, 1999 letter to Mr. Rowe. The Implementation Report provides, among other things, details of specific T&D upgrade projects within the City that are currently underway and planned for the immediate future.

One of the purposes of the Investigation Report is to present ComEd's explanation of the latent deficiencies that caused certain parts of the T&D system to fail in late summer, and ComEd's action plan to address them. For much of the past 18 months, ComEd has endeavored to address the obvious faults in the system. But today, although many of the more visible faults have been cleared away, other, less obvious but more substantial deficiencies are coming to light. The extremely thorough work underlying the Investigation Report has revealed real problems in system design, inspection and maintenance, and in the management of those systems.

These problems have heretofore escaped the recognition of responsible managers and independent evaluations alike. As set forth in the System Reliability section of this Report, the performance of the ComEd system compared favorably with industry norms until stressed by the extremes of weather and load experienced in 1998 and 1999. In the end, it is ComEd's challenge to find and resolve those problems as expeditiously as possible, so that it can continue the business of delivering power and focus on restoring public confidence in its service.

The Investigation Report includes an immense amount of information about ComEd, about how it is organized, how it operates, and how it will improve its reliability of service. With the help of the special task force made up of ComEd specialists and industry experts, ComEd has identified five key areas where it can and will improve its performance:

- **Maintenance**
- **Equipment Protection and Monitoring**
- **Load and Capacity**
- **System Optimization**
- **Organization and Management**

By implementing the recommendations outlined in the Report, ComEd believes it will be able to produce the only kind of results that count – *results that can be seen and felt by ComEd's customers and the officials who represent their interests*.

The Investigation Report is organized around these five critical areas. For each area it provides a detailed account of ComEd's findings, the most urgent concerns identified as a result of those findings, and the steps that ComEd will take or has taken to address those concerns and improve reliability. The Report provides a detailed and comprehensive explanation of the problems ComEd has identified, along with an equally detailed and comprehensive explanation of the proposed solutions. Beginning December 15, 1999, ComEd will present quarterly status reports on the implementation of the program outlined in the Report to the ICC, the City and other appropriate officials.

Background

"Nothing Matters If We Don't Keep the Lights On"

It is certainly fair to say that the events of July and August triggered a series of alarms at ComEd regarding the extent of the T&D challenges ComEd faces. But it would be overly simplistic, and a disservice, to suggest that ComEd, the City, the ICC, public interest advocates, and other concerned leaders were unaware of or unresponsive to the serious nature of the T&D deficiencies long before July 30.

In 1998, the Board of Directors of Unicom, the parent company of ComEd, selected John Rowe to be Chairman and Chief Executive Officer of Unicom and ComEd. Mr. Rowe assumed these positions on March 16, 1998, with a mandate from the Board to deliver increased shareholder value while meeting ComEd's continuing public service responsibilities, implementing the Illinois Restructuring Act and building a competitive energy business.

To ComEd, John Rowe's message from the top was simple and unambiguous, and heard from the very first: "Nothing matters if we don't keep the lights on."

Obviously, "keeping the lights on" is a fundamental requirement of ComEd's public service obligation, and it became the number one objective in Mr. Rowe's strategic plan (Unicom Directions) that was unveiled in July of 1998. However, as a series of mainly weather-related outages occurred over the course of his first eight months with ComEd, Mr. Rowe became increasingly concerned that the public's experience of ComEd's reliability and ComEd's assessment of its own performance did not match up.

Mr. Rowe regularly told public audiences about the internal discussions which reflected this disconnect. "The T&D people tell me we're in the 1st or 2nd quartile for national reliability," he explained. "So I say to them: 'If we're so good – then why are so many customers mad at us?'"

By the fall of 1998, Mr. Rowe was questioning whether the T&D budget was sufficient to address ComEd customer needs, and he asked the T&D division to present a budget that allowed for substantial performance improvements. As a result, ComEd expanded its three-year (1999-2001) capital budget for T&D improvements by $307 million, and its tree-trimming program by $30 million.

And in 1998, John Rowe was far from alone in his concerns about ComEd's distribution operations.

More than a year ago, the ICC, the Mayor of Chicago, the Legislature, the Attorney General, the Citizens Utility Board, several suburban mayors and other respected voices raised serious concerns about the condition of some of the company's T&D equipment and infrastructure. The ICC and the Attorney General, for example, launched a series of inquiries and meetings. The City of Chicago had previously initiated an arbitration proceeding. ComEd believed at the time, and said through its new Chairman, that the issues raised by these entities were legitimate, and ComEd agreed to address them.

In particular, Mr. Rowe acknowledged that the Mayor had a strong case. As a result, Mr. Rowe decided to settle the arbitration initiated by the City rather than prolong it through litigation. This decision resulted in a historic settlement in which the City secured a binding contractual commitment from ComEd with reliability-related T&D investments and expenditures that tally more than $1 billion. The <u>implementation</u> of that Agreement is the subject of the report to the City which was also released today.

In addition, ComEd's leadership worked in close cooperation with the mayors and the Legislature to bring about the 1999 legislation which resulted in a $2 billion commitment by ComEd to T&D and other upgrades in areas outside the City. But the very fact that the company had previously challenged these legitimate T&D concerns raised an issue at ComEd almost as serious as the problems in the T&D system itself. As Mr. Rowe candidly observed last month: "It is a bad thing when you get better information from the Mayor of Chicago, a variety of aldermen and a variety of suburban mayors than you are getting from your own management reporting channels."

By last winter, Mr. Rowe recognized that ComEd needed an outside expert to help break through logjams in internal information flow, and to bring an independent perspective to the company. In February 1999, Mercer Management, an outside consultant with extensive experience in the industry, was brought in to conduct a comprehensive, unbiased, hard-eyed look at ComEd's service reliability and other critical systems. Substantial portions of that early and continuing assessment are incorporated in the attached Report.

ComEd also sought input from the communities it serves through the Green Board process, which the Chairman launched last winter. ComEd went to the communities to find out how it was doing, then used that information as a touchstone against which to test the T&D claims of the company's internal management personnel. It was an effort to focus not on ComEd's assessment of <u>its programs</u>, but on the customers' views of <u>their service</u>.

The process worked. Out of more than 400 participating wards and municipalities, 31 communities initially rated as "red", meaning that service was unacceptable. Less than a year later, the company's concentrated response had reduced the number to only two (though the number increased to eight after this summer's outages). The process also served as a kind of an early warning system, helping ComEd's leadership to quickly identify and respond to communities where reliability problems needed the most attention. For example, before 1999, the Village of Flossmoor had experienced what the Mayor described as frequent, lengthy and intolerable service interruptions. Following a focussed response via the Green Board process, the Mayor saluted the local ComEd manager for his "extraordinary performance" and thanked John Rowe for his "leadership in redirecting ComEd priorities and funds to the issue of electric reliability and particularly for the work that has been performed to date in our Village."

For all these reasons, in the spring of 1999 – four months <u>before</u> the events of July 30 – ComEd began searching for a new leader to take over the T&D team and guide it through the major upgrades promised to the City and the Legislature. The company tapped Carl Croskey, a respected figure in the energy distribution industry with a solid

reputation and 25 years of experience. But before Mr. Croskey could even start, the lights in West Bucktown began flickering out.

<u>What Went Wrong</u>?

As is now widely known, and as was spelled out in some detail in ComEd's September 1, 1999 chronology to the Mayor of Chicago, the first major blackout of the city's late summer heatwave began beneath the manholes which dot California Avenue. In the early morning hours of Friday, July 30, the 12 kilovolt line feeding into Cortland Substation's Transformer 1 short circuited. ComEd switched the customers served by that line to one of the two remaining transformers, and service continued largely uninterrupted until late in the morning.

Then at 11:24 a.m. the cable known as Line 5348 suffered a fault feeding into Cortland's Transformer 3. The fault triggered the circuit breaker on Line 5348 and Transformer 3 went down. And in the first of the series of domino falls that were to plague the city that weekend, the last remaining transformer at Cortland then began to overload. Within minutes it, too, was shut down, and with it went Cortland Substation and over 10,000 customers. It was the hottest day of the summer, and the hands on the clocks in West Bucktown had stopped at just about high noon.

ComEd dispatched a work crew immediately. The workers were inside the manhole and had the cable repaired in little more than an hour. But as was later reported in the press, what they did not know was that Line 5348 had failed in not one place, but <u>two</u>. A smaller fault was lurking behind the larger one, where it could not be detected by test equipment. When the switch was thrown and the cable re-energized, the hidden fault shorted out and two more transformers went down, this time at the Northwest Substation. By 4:30 p.m. the power was gone and the AC was out in nearly 100,000 homes centered around Independence Park.

But despite the stopped clocks, alarms bells were ringing across the city as concerned officials at ComEd, the ICC, the City and other organizations realized that the situation they had feared and worked together for months to prevent was now unfolding during what the *Chicago Tribune* later calculated was the fourth hottest week of the century.

As all of Chicago is now only too aware, the hidden fault on Line 5348 and the shutdown at the Cortland Substation was only the beginning. Cortland marked the first of a series of outages that weekend, spanning four days as July rolled into August. Public anger rose along with the temperature as a series of T&D components failed over the next five weeks, disrupting activities throughout the city. The manhole fires at Cortland Avenue on August 9 and 10 left more than 8,200 customers without power. Failures at two substations resulted in the Loop outages of August 12, sparking business closures and traffic disruptions as workers went home early. Ten days later another outage affected three Chicago icons – Meigs Field, Lake Shore Drive and the Field Museum. And when three out of four transformers at a downtown substation failed, another icon was in the news as service to the Richard J. Daley Center was disrupted just as the business day began.

<u>ComEd's Emergency Response</u>

The unrelenting series of highly visible, back-to-back service interruptions which struck in July and August dramatically exposed the true depth of problems that have troubled customers, ComEd and public officials for a number of years. The company's response was unprecedented.

ComEd hit the ground running. The Chairman spoke plainly to the public. ComEd met frequently with concerned and involved representatives of the ICC, the City of Chicago and various wards and municipalities to keep them apprised of ComEd's progress and to invite and welcome their input.

Two days before the August 12 outage, Mr. Rowe assigned David Helwig to head up a new T&D task force to address the outages. Mr. Helwig is one of the industry's most experienced turnaround experts and a skilled engineer with a background in both T&D and nuclear programs. Working under Oliver Kingsley, Mr. Helwig had already been recognized for his success and discipline in introducing fundamental change within ComEd's troubled nuclear programs, and Mr. Rowe asked him to step in and bring the same focus to T&D improvements. Within 48 hours, Mr. Helwig's mission was expanded to running the T&D organization on an interim basis, pending the arrival of Carl Croskey, and to leading an emergency, system-wide assessment of the condition of the equipment.

By the time the last service was restored on August 12, ComEd had already dispatched more than 700 men and women to open manholes and explore substations across the City in a broad but focused effort to search out and prevent any avoidable interruptions. All told, during the past six weeks, ComEd devoted an estimated 250,000 additional manhours and over $20 million to the response, above and beyond normal operations.

According to industry professionals, the month-long effort which began on August 10 is unprecedented in its speed, scope and intensity. Dr. Karl E. Stahlkopf, Vice President – Power Delivery at the Electric Power Research Institute (EPRI), is recognized throughout North America as one of the industry's most experienced and respected experts. Dr. Stahlkopf has participated closely in ComEd's investigation since shortly after it began. Comparing ComEd's mobilization of people, money and material to Operation Desert Storm, Dr. Stahlkopf called it "the fastest, fullest, most comprehensive T&D investigation ever launched in the history of the industry." Dr. Stahlkopf characterized both the investigation and the resulting Report as a "clear-eyed, hard-hitting effort by the company to take a blunt look at itself, its equipment, its design, its personnel and its operations."

The overall response has proceeded on two parallel tracks. The first mission was to inspect and assess the actual equipment—the <u>material condition assessment</u>. The second parallel mission was the expert analysis of the system <u>design</u> itself.

For the material condition assessment, one of the most critical imperatives was to map out and identify the nature and extent of the most serious and time-sensitive challenges, and to do so quickly. The scope of the tasks completed in the days since the outages is nothing short of extraordinary. During the first ten days alone, ComEd employees inspected virtually every one of ComEd's 888 substations. They completed some 1387 inspections of the underground system alone. By August 30 – barely two weeks after the task force was first convened – ComEd employees had identified 212 potential faults in cables and transformers, and had already repaired 114 of them.

In tandem with this massive assessment of the material condition of its T&D system, Mr. Helwig assembled a team of the most experienced experts in America to assess the operation and management of its T&D system, drawing extensively on the technical expertise of the EPRI and consulting with such industry leaders as General Electric, Kenny Construction and Asea Brown Boveri (ABB).

By August 14 (two days after the critical failures that shut down the South Loop), ComEd had already assembled 25 best-in-class technical experts from the EPRI to assist with a technical review of system capabilities. Known worldwide as the preeminent electric power research and development organization, the EPRI experts were chartered with leading a complete, "no holds barred" assessment of ComEd's system deficiencies. Working almost non-stop for 12 days, many of these experts have participated since the beginning of this investigation. The results of their work were presented to a panel of industry experts in formal sessions on August 26 and September 10. The panel acted with new voices to challenge old ways of thinking, and to present solutions ranging from time-tested to cutting edge. ComEd has also extended invitations to the ICC and the City of Chicago, who have been participating in the investigation and weighing the analysis as the results of ComEd's technical review panels began to pour in.

With brutal candor, and with aggressive specificity, both ComEd's own professionals and its team of nationally recognized experts from outside the company have been probing, testing and scrutinizing the T&D system, and ComEd has taken an unflinching look at an unflattering reflection. The attached Report is the result of that initial search.

But ComEd recognizes that people are not only asking about what happened to Line 5348 at Cortland Substation. People are not only asking about what happened to the <u>cable</u>. They also want to know what happened to <u>ComEd</u>.

The real answer to that question does not turn on which lines short-circuited or which transformers overheated or which substations lost power. The real answer to that question must address why all of the many fail-safes and redundancies programmed into the system failed to prevent the outages. And that answer is a slightly longer story.

<u>Task Force Findings – Latent Deficiencies in Cables and Companies</u>

As with the hidden fault on Line 5348, ComEd has found that it solved one set of problems only to find another set lurking behind the first. Not all of them can be quickly fixed.

ComEd understood that there were issues with its T&D system – that is why it had been working so closely over the past year with the ICC, the City and numerous other interested parties to address those problems. Nevertheless, the <u>extent</u> of the problem was not anticipated. There are serious issues with both the maintenance and the design of the system. But with the initial investigation complete, these issues can now be fully addressed.

The findings of the investigation are based substantially, but not exclusively, on investigations by the task force. July 30 was not the first time alarm bells rang on this watch. The ICC, the Mayor of Chicago, and Mr. Rowe all raised concerns about ComEd's T&D system as much as 18 months ago, and have put a great deal of effort into identifying and prioritizing the T&D challenges and projections leading into the year 2000 and beyond. Some of the credit for the impressive results the task force was able to generate in such a short time must go to these parties, and to the far-ranging evaluation, debate and cooperative analysis that they contributed to the matter.

As noted above, ComEd has identified five areas of operations in which it failed to meet the expectations of itself and its customers. A detailed description of the steps ComEd has taken and will continue to take in pursuit of improvement is set forth below and in the Report. Given the recent outages, however, today both ComEd and the community have come to recognize that the problems identified in its earlier assessments run farther and deeper than could previously have been understood, and that each of these five factors played a part in the outages of July and August 1999.

(1) <u>Maintenance</u>: As the tortured summer saga of Line 5348 suggests, the investigation found that a utility like ComEd needs to be painstaking in the care and feeding of its T&D components. The team found that other major cities operate T&D equipment that is no newer, no older -- not fundamentally different from ComEd's. The task force findings pinpoint the crucial difference between ComEd's equipment – which failed this summer – and similar systems elsewhere that did not: ComEd has been unable to provide the rigorous care and maintenance that the T&D system requires for optimal reliability.

It was generally found that while ComEd's inspection programs seemed appropriate, there were only imperfect mechanisms in place to ensure execution. It looked good on paper, but the repeated outages made the truth of the matter painfully clear. It is not certain, from a review of the records, how often inspections were actually performed, and the inspections that <u>were</u> performed may have been too passive, too cursory, to truly maintain the system.

Additionally, the Report concludes that ComEd needs to ensure better follow-up on maintenance requests. While virtually all T&D emergencies are dealt with immediately, there appear to be altogether too many deficiencies which, had they been identified and addressed sooner, would not have become critical in the first place. Too often, the priority of requests for maintenance was not recognized, and the request was simply added to a list. The Report also indicates that routine maintenance requests on the list were rarely tracked to ensure follow-up, and that the list was rarely updated to indicate which requests had already been addressed.

Specifically, the Investigation Report presents the following findings about ComEd's maintenance program:

- Management Systems. ComEd's maintenance program is hampered by incomplete definition, lack of focus, historic budget swings, suboptimal work planning and inconsistent supervision.

- Equipment Monitoring and Capacity Management. Too much of ComEd's maintenance work is reactive rather than preventive, driven by actual or pending equipment failures, because of insufficient monitoring and inadequate capacity (monitoring and capacity are discussed separately below).

- Program Execution**.** ComEd's maintenance program has been hindered because of gaps in equipment condition monitoring, inconsistent training and work practices, and unclear priorities.

- Recordkeeping and Documentation**.** ComEd maintenance efforts are often made more difficult by incomplete operating histories of components due to gaps in data capture, inattention to detail, and lack of workforce discipline.

Solution. ComEd has already begun to implement the experts' recommendations regarding its maintenance program. First and foremost, ComEd has continued the massive inspection and repair program that it initiated on August 10. This intensive effort has been sustained across all areas of the T&D system and (as of September 10) led to:

- 4,346 completed, state-of-the-art inspections
- 8,828 items requiring maintenance
- 2,304 completed repairs

The details of these efforts are contained in the Report. ComEd will continue with its accelerated inspection and repair program. The Report makes detailed recommendations regarding the required maintenance of every aspect of ComEd's T&D system, but the general thrust of the recommendations is simple: provide the necessary authority and make the managers directly accountable for the performance of the system. That one, single change will carry all the other changes in procedures (different inspection schedules, methods, records, and tracking) down to the people who have to implement them.

(2) Equipment Protection and Monitoring: As mentioned above, ComEd's physical equipment is largely comparable to that of other utilities in major metropolitan areas. In addition to improving its maintenance practices, however, ComEd needs to strengthen its equipment monitoring and protection. By improving its monitoring practices, ComEd will be better able to predict when certain types and pieces of equipment are likely to wear out or fail. Predicting (and thus preventing) the on-line failure of a component helps protect the equipment around it: when one component fails, the power originally carried by that component must travel through alternative routes using the surrounding components. This is what happened on July 30, when the sudden overload caused by the failure of Line 5348 acted to shut down the adjacent transformers.

Specifically, the Investigation Report presents the following findings about ComEd's equipment protection and monitoring:

- Maintenance Program Ownership. It was not always clear who was responsible for specific elements of ComEd's protection and monitoring program. Even when the responsible party was clearly identified, he or she was not always held accountable, in a meaningful way, for the performance of those elements.

- Calibration Maintenance. ComEd has not kept pace with the necessary relay calibrations, and its efforts to do so are hampered by the same types of issues described above with respect to other types of systems maintenance.

- Root Cause Analysis. ComEd has not effectively tracked and analyzed information about relay failures, and thus cannot analyze or address the root causes of those failures.

- Equipment Condition Monitoring. ComEd has not implemented a consistent program of equipment monitoring across its system, thus limiting its ability to detect incipient failures.

Solution. As with the maintenance program, the Report makes detailed recommendations regarding the protection and monitoring of ComEd's T&D equipment, including the utilization of readily available but state-of-the art monitoring devices. Also as with the maintenance program, the general thrust of the recommendations is to give managers the necessary authority and then make them directly accountable for the performance of the system.

(3) T&D Load and Capacity: It is obvious from the system failures this summer that the ComEd power delivery system is overloaded at some points. ComEd was aware that certain substations were overloaded at times of peak summer demand and was working to address the situation as outlined in its agreement with the City of Chicago. But the recent investigation revealed that the extent of the problem had been underestimated. ComEd's experts calculate that the T&D system is five to ten percent deficient in its capacity to carry the peak load which must be contemplated in the wake of this summer's experiences. The problem is not a lack of power. Between construction, importation and its fleet of nuclear plants, ComEd expects to have a sufficient supply of power. The problem is that the distribution system cannot reliably deliver the power to its customers at peak times. ComEd needs to redesign some parts of its system to make better use of the physical components that are already in place, and invest in greater capacity to help it carry the load.

Specifically, the Investigation Report presents the following findings about the load and capacity of ComEd's T&D system:

- Substation Capacity. Upon initial review, it appears that almost a third of ComEd's large substations (approximately 73) operate above capacity at times of peak demand, and that 27 of those substations require expedited corrective actions.

Three of those 27 substations are located in the City of Chicago (Crosby at 1180 North Crosby, Lakeview at 1141 West Diversey, and Northwest at 3501 North California), and 24 are located outside the City.

- Distribution Feeder Capacity. Upon initial review, it appears that almost one fifth of ComEd's small substations and feeders (approximately 880) operate above capacity at times of peak demand; 185 of those small substations and feeders are located in the City.

ComEd has already begun to implement the experts' recommendations regarding load and capacity issues. ComEd is continuing its ongoing assessment of the load and capacity of its existing substations in order to properly prioritize necessary repair and replacement. At the same time, ComEd is working to determine which substations will required additional equipment – or where ComEd will need additional substations – and how ComEd will surmount the difficulties inherent in expanding or installing substation capacity. ComEd will repair, upgrade or otherwise increase the capacity of the substations requiring expedited action by June 15, 2000. The other substations will be addressed by June 15, 2001. The extensive improvements to the material condition of the equipment will also help ease the load on the transformers until all of the various repairs, replacements, and additions are completed.

(4) T&D System Optimization: The distribution system serving downtown Chicago has evolved over the years to a condition that is particularly sensitive to inaccuracies in planning and the impacts of maintenance outages and equipment failures. Its apparent radial design is really an arrangement of radial arms of electrical loops similar to that employed in many highly reliable European designs, except with less capacity and configuration redundancy. It is the uniformly high loads carried on the system and the limited load transfer capability which combine to make this an unforgiving situation. Additionally, the ComEd system was found to contain some unique and limiting features which compound the impact of equipment outages and failures.

Achievement of improved service reliability will require the careful balancing of capacity additions and configuration enhancements.

Specifically, the Investigation Report presents the following findings about the load and capacity of ComEd's system design:

- System Design. ComEd's downtown distribution system lacks some of the features which provide high reliability and flexibility in other US and European designs.

- Delivery Capacity. Additional power delivery capacity is needed to provide the operating flexibility and contingency management capability needed to ensure highly reliable service.

- System Operation. Traditional contingency planning criteria applied to this system will not provide the requisite reliability for such an important area.

Solution. ComEd has already begun to implement the experts' recommendations with regard to its system design. Recognizing that quality system design is the fundamental building block for delivering reliable service, ComEd has retained Asea Brown Boveri (ABB) to collaborate with ComEd system planners to diagnose faults in the system design and identify ways to remedy those faults. Led by Lee Willis, a world- renowned expert in electric utility system planning, ABB is objectively reviewing the design and performance of ComEd's T&D system. Using advanced, proprietary models to understand the dynamics of power flows, ABB has completed its initial diagnostic review comparing ComEd's system to other designs, evaluating the system's capability to deliver reliable service, and considering options for improvement.

With ABB's preliminary analysis complete, ComEd is now in a position to go forward with the more detailed assessment that is currently underway. The ongoing System Optimization Study, which will be complete by year-end, involves further system modeling and sensitivity analyses. The study will identify the best way to increase the capacity of the system through some combination of capacity improvements (e.g., increased transformer and line capacity) and configuration enhancements (e.g., loops and networking, more and better switching). A number of the world's foremost equipment manufacturers have been asked to devise practical solutions tailored to the system's needs in order to implement those solutions as quickly as possible. Until that time, ComEd will focus on improving efforts at upgrading, maintaining and monitoring the system in its current configuration.

(5) Organization and Management: As the results of the investigation have unfolded, a wide variety of underlying organization and management issues have surfaced. A series of realignment workshops used to establish the transition organization for T&D (as described below) identified further evidence of the same issues, confirming the findings of the investigation with respect to organization and management issues. The issues identified in the Report fall into five categories, all related to just "doing the work": leadership, organization design, work processes, information systems and staff.

Solution. As with the other areas of concern identified in the investigation, ComEd's senior management and the interim T&D leadership moved immediately to implement the experts' recommendations with regard to ComEd's organization and management. Over the past 45 days ComEd has made selective changes to the composition of the T&D senior management team and has established a disciplined, interim organization to implement the immediate drive to inspect and repair the system components. This interim organization has already initiated many of the internal measures recommended by the experts, including:

- Re-evaluating the entire T&D budget to ensure that resources are being allocated to the programs that will most benefit from expenditures.

- Developing specific performance goals for the T&D program, to assist in gauging (and enforcing) progress.

- A general “house cleaning” -- e.g., inserting of new leadership, participating in a public and no-holds-barred review of shortcomings, and instigating stepped-up employee dialogue and communications.

To the extent that ComEd’s efforts along these lines have already yielded results, those results are set forth in the Report.

Although these moves only scratch the surface, they have set the stage for a more thorough restructuring of the T&D organization. Among the initiatives that ComEd will pursue over the next 90 days (set forth in detail in the Report), ComEd will:

- Aggressively recruit new members for the T&D management team and provide additional training for existing managers.

- Educate employees about new practices and goals, then hold them accountable for the attainment and implementation of those practices and goals.

- Track the continuing execution of the many new programs that ComEd has set in motion over the last 45 days.

Each of these five factors – maintenance, equipment protection and monitoring, load and capacity, system optimization, and organization and management – likely played some role in the outages that occurred in July and August. Improvements in these five areas will go a long way toward preventing similar service interruptions in the future. ComEd expects the results of the above actions to be as significant and far-reaching as those recently brought about by Oliver Kingsley and David Helwig in ComEd’s Nuclear Generation Group.

A Blueprint for Change

The Road Ahead

The Mayor has said that the company needs to start at Ground Zero.

He says ComEd had better change.

We agree. **And we have.**

ComEd recognizes that fundamental change in T&D performance requires an across-the-board effort. *A chain is only as strong as its weakest link*.

That is why, with this Report, ComEd is announcing a new, two-year recovery program, designed to accelerate fundamental change within Commonwealth Edison.

It calls for new initiatives and new ideas that range across the board. A five part plan that calls for new <u>people</u>, new <u>programs</u>, new <u>perspectives</u>, new <u>proposals</u> – and most importantly – new <u>performance</u>.

<u>New People</u>

ComEd is seeking to recruit and promote a new generation of managers and leaders with vision, discipline and talent. Under the new leadership of professionals like John Rowe, David Helwig and Carl Croskey, that process has already begun. For example, for the next several weeks, David Helwig will continue to direct the <u>investigation</u> into the summer's outages and the efforts to create a program to address the problems identified in that investigation. Carl Croskey, joined by other new leaders, will take over the <u>execution</u> of the program in his capacity as Senior Vice President in charge of ComEd's energy delivery business.

<u>New Programs</u>

ComEd is seeking and proposing core, fundamental change. New programs mean new discipline and accountability, especially for the T&D maintenance programs. It means accelerating steps to protect vital equipment and to monitor it with simple, readily available and yet state-of-the-art technology. It means advancing construction and enhancement programs to increase system capacity. And most of all it goes directly to ComEd's plans for a highly focussed effort to identify and design a system that is fully optimized and ready to meet the needs of a new century.

<u>New Perspectives</u>

ComEd recognizes the benefits of the cleansing power of <u>daylight</u>. ComEd and its customers will benefit from the continued, bare-knuckled scrutiny by the public, public officials and outside experts representing many disciplines and perspectives.

ComEd invites this scrutiny and also welcomes appropriate participation by the ICC, the City, the Attorney General, Cook County, the Citizens Utility Board, suburban municipalities and other interested parties. Throughout its investigation ComEd has invited each of these entities to forge a cooperative, forward-looking partnership to address the most crucial needs of the people we collectively serve. And ComEd remains ready to join in such a partnership now.

<u>New Performance</u>

ComEd stands ready today to match rhetoric with resources – a commitment of bottom-line dollars to the largest, most accelerated capital improvement program in the history of the company.

This new and accelerated commitment of dollars represents not only ComEd's investment in the future – but also its <u>confidence</u> in the future. ComEd understands why people are angry, and why people want more than another series of promises. Both the public, and the public officials who represent them, deserve to know that these new pledges are backed up by hard dates, firm standards and an enforceable timetable.

Timetable

ComEd has already accomplished much. In the words of John Rowe, ComEd's employees "have worked with ever-increasing intensity, making radical improvements in record time." But there is still much more to be done. Over the next three months ComEd will continue to implement the recommendations set forth in the Report. ComEd will be laying cable, installing monitors, training inspectors and upgrading transformers. Each of these steps is part of a larger, front-loaded program, which ComEd will continue to implement over the next two years:

By December 15, 1999:

System Load, Capacity and Design

- Complete Comprehensive T&D System Optimization Study
- Establish and Prioritize Plans to Relieve Load Capacity Shortfalls
- Establish New ComEd Planning Criteria for Forecasting Load
- Complete Sensitivity Analyses Needed to Prioritize Work

Inspection, Maintenance and Monitoring

- Submit 1st Quarterly Status Report to ICC, City and Others
- Establish New Process for Scheduling and Allocating Field Work (including maintenance and monitoring)
- Continue Acceleration of ComEd Vegetation Management Program
- Establish New Schedule for Inspections; Replace Faulty Monitoring Equipment

Management

- Redesign Organization, Core Processes and Information Systems/Technology
- Establish Processes to Enhance and Enforce Commitment Tracking (such as repairs, replacements, upgrades, etc.)

City Projects (as per Settlement Agreement)

- LaSalle Substation: install and activate second 138 kV transformer
- Northwest Substation: develop plan for upgrades
- Kingsbury/Ohio Substations: develop plans to accelerate upgrades
- State Line to Taylor: complete installation of 138kV line (#0702)

<u>By June 15, 2000</u>:

System Load, Capacity and Design

- Repair, Replace or Upgrade the 27, High Priority, Major Substations
- Repair, Replace or Upgrade All Identified, High Priority, Small Substations and Feeders

Inspection and Maintenance

- Submit 2nd & 3rd Quarterly Status Reports to ICC, City and Others (on March 15 and June 15, respectively)
- Optimize Maintenance & Tracking on Any Remaining Substations and Feeders (major and small and feeders operating in excess of capacity)
- Achieve 4-Year Tree Trimming Cycle
- Complete Aerial Inspection of Overhead Transmission Lines

City Projects (as per Settlement Agreement)

- <u>Washington Park to Taylor</u>: complete installation of third 138kV line (#13701)
- <u>Northwest Substation</u>: complete upgrade of Terminal 2 12kV switchgear

<u>By December 15, 2000</u>:

Maintenance

- Submit 4th & 5th Quarterly Status Reports to ICC, City and Others (on September 15 and December 15, respectively)
- Establish Single Source Data Base for Misoperation Information

System Design

- Implement Performance Metrics for Capacity Planning

Management

- Implement a Fully Integrated Work Management Program at ComEd

<u>By June 15, 2001</u>:

System Load, Capacity and Design

- Repair, Replace or Upgrade Any Remaining, High Priority, Major Substations
- Repair, Replace or Upgrade Any Remaining, High Priority, Small Substations

and Feeders

Maintenance

- Optimize Maintenance and Tracking on Any Remaining Substations (operating in excess of capacity)
- Submit 6th & 7th Quarterly Status Reports to ICC, City and Others (on March 15 and June 15, respectively)

ComEd has set a formidable series of tasks for itself. We know that fundamental change takes time. To complete the revolution described here today will take more than the 45 days since the outages that have outraged many customers. ComEd will have a better perspective on the final timetable when the System Optimization Study is issued in December, but it intends that those changes will take place over a two-year timetable.

But far sooner than this, we intend to, indeed we <u>must</u>, produce discernable and measurable improvements in performance. By next summer, ComEd's customers will be experiencing fewer interruptions, and those that do occur will be shorter in duration. Make no mistake, however. So long as there are snowstorms, windstorms, wildlife and Mother Nature's trick bag, there will always be times when electrical power systems fail. The commitment ComEd is undertaking is to bring its performance up to the highest levels that can be achieved within the limits of the practical world in which we live.

The events of the past two months have been sobering to everyone in the ComEd house. There is no satisfaction in finding these problems. But there is some satisfaction, at long last, in facing them.

And at the same time, in closing, some real world perspective is in order. As noted at the outset, in medical terms, the T&D system is in serious but stable condition. The prognosis – including the <u>immediate</u> prognosis – is, in fact, good. As the *New York Times* observed on Monday, reporting the views of the North American Electric Reliability Council, our utility systems are not falling apart.

Yes, America this summer suffered a troubling series of major outages. New York City was hit by its worst blackout in over 20 years. Half a million customers lost power in New Orleans. In both these cities, as in Chicago, the systems proved vulnerable to the twin summer challenges of extreme heat and extreme demand.

But today autumn is coming to Illinois and with it a seasonal reduction in both temperature and demand. Given the extraordinary, accelerated and highly focussed T&D improvement campaign that was launched a month ago, ComEd is staking its future on its ability to meet next summer's challenges before Memorial Day comes to pass.

ComEd knows that it has to act quickly. ComEd understands that, with the release of this Report, the time for explanations is past. ComEd recognizes that, from this day forward, it will be judged by only one measure – <u>performance</u>.

We are aiming higher – for our company, for our customers and for the communities we serve – yours. And make no mistake. The end goal of this response, and the overall goal of this company, is to ensure that – among America's major metropolitan utilities – Chicago and ComEd are second to none.

As for anything less, John Rowe put it bluntly in the aftermath of the August outages. He said: **"I will not tolerate it. And you will not have to."**

# # #

REQUEST CUB/OEUC 121:

On pages 400/9-10 Mr. McDermott discusses the protections that come from the OPUC ring-fencing and rate-making authority (the ability of the Commission to exclude costs not related to utility operations or that are imprudently incurred). Please explain how these protections can be used to insure that the necessary investment is being made in the utility's infrastructure and prevent the underinvestment that Oregon experienced with US West and Illinois experienced with Commonwealth Edison.

APPLICANTS' RESPONSE TO REQUEST CUB/OEUC 121:

Although not discussed in Dr. McDermott's testimony, the Commission's ratemaking and ring-fencing authority ensure that necessary investments are made in the utility's infrastructure and prevent under-investment as follows:

- **Ratemaking**: The Commission's authority to set rates includes its ability to review capital and O&M expenditures for prudence. This process provides an incentive to the utility to invest in a prudent manner in order to be allowed to recover those costs. Conversely, the Commission's authority to set rates includes the ability to disallow any imprudently incurred costs, including costs the utility may incur as a result of any imprudent under-investment.

- **Ring-fencing:** Ring-fencing encourages prudent investment and discourages under-investment by ensuring that the utility is adequately capitalized.

In addition, the regulatory authority that the Commission has over PGE extends beyond ratemaking and ring-fencing. As Dr. McDermott notes in his testimony, the Commission can also ensure that necessary investments are made in the utility's infrastructure and prevent under-investment through the following means:

- **Investigation ability**. The Commission has the ability to investigate PGE's budgets for capital expenditure and operation expenses. This provides an incentive to the company to prudently invest.

- **Integrated Resource Planning**. PGE must file a new Integrated Resource Plan every two years. Through this process, the Commission and interested parties are integrally involved in PGE's long-term planning and capital expenditures related to the acquisition of generating resources. PGE incurs substantial risk if it fails to acquire resources in accordance with an acknowledged plan. Thus, this process provides another incentive for the utility to invest prudently in the utility's future.

- **Merger Conditions (other than ring-fencing)**. As an example, Oregon Electric has agreed to extend the service quality measures for ten years. These measures provide feedback to the Commission on how the company's reliability is changing over time. When combined with the Commission's other authority as noted above; this provides a potent check on any incentive to imprudently under-invest.

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REQUEST CUB/OEUC 122:

(1) On pages 400/17-18, is Mr. McDermott asserting that the PUC can command a utility to make certain investments? (2) Is Mr. McDermott asserting that all utility investments and investment schedules are completely transparent and readily accessed by the Commission?

Note: Numbers inserted in text of request to aid in response.

APPLICANTS' RESPONSE TO REQUEST CUB/OEUC 122:

(1) No, in the referenced section of Dr. McDermott's testimony, Dr. McDermott is asserting that the Commission has the following authority:

- To supervise PGE's least-cost planning process and ensure that the Least Cost Plan includes sufficient capital expenditures to maintain reliable, efficient, and cost-effective service.
- To monitor and investigate PGE's operations and order PGE to rectify any deficiencies in practice or investment that it believes are endangering the long-term safety and/or reliability of the company's services.
- To disallow costs that are imprudently incurred.

(2) Applicants object to this request as vague and ambiguous. Subject to and without waiving these objections, Applicants submit the following response:

It is Dr. McDermott's understanding that the Commission has the right to obtain any information necessary to enable the Commission to perform its duties (ORS §§ 756.070 & 756.075).

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REQUEST CUB/OEUC 120:

On page 400/18, Mr. McDermott argues that PGE's owners will be motivated to maintain the utility's long-term health to maintain a positive relationship with the Commission.

a. If PGE's owners do not intend to be around for the long-term, why are they so motivated?

b. Can Mr. McDermott imagine a scenario where it is more profitable to skimp on an investment or investments even if it causes concern for the regulators?

c. Is Mr. McDermott familiar with US West's service quality history in the state of Oregon?

d. Is Mr. McDermott familiar with the investigation of the 1999 Illinois power outages by the ICC which found that Commonwealth Edison "spent $225 million less than its cumulative budgeted capital spending" for 1992 to 1998? (see ICC news release 6/8/2000)

e. Did Commonwealth Edison under fund its investment in its distribution system for nearly a decade before state regulators took action? If so, why did the regulatory oversight fail? If not, does Mr. McDermott dispute the finding of the Liberty Consulting Group's 2000 report to the ICC?

f. Why does Mr. McDermott believe that Commonwealth Edison failed to adopt "a recommendation for increased tree trimming from a 1992 audit" conducted for the ICC? (see ICC news release 7/19/2000)

APPLICANTS' RESPONSE TO REQUEST CUB/OEUC 120:

a. Please see the Rebuttal Testimony of Karl A. McDermott on Behalf of Applicants (Oregon Electric/400, McDermott/18), the Rebuttal Testimony of Jerry Jackson on Behalf of Applicants (Oregon Electric/300, Jackson/6-7), and the Rebuttal Testimony of Kelvin L. Davis on Behalf of Applicants (Oregon Electric/100, Davis/6-14, 18-23).

b. Applicants object to this request as overly broad, unduly burdensome, argumentative, and calling for speculation. Subject to and without waiving the foregoing objections, Applicants submit the following response:

Dr. McDermott cannot speculate about hypothetical scenarios where it might conceivably be "more profitable to skimp on an investment or investments even if it causes concern for the regulators." That said, as described in more detail in Dr. McDermott's testimony cited above, one measure of a utility's value is the value of the utility to a third party if and when it is sold. If there is under-investment, it is likely that a third party will become aware of this in due diligence, which could adversely affect the future sale price. In addition, if the regulators are concerned about under-investment, then that implies an unfavorable regulatory environment, which is another factor that could adversely affect the future sale price.

c. No.

d. Dr. McDermott is generally familiar with the Illinois Commerce Commission's ("ICC") investigation of the 1999 Illinois power outages. However, the ICC did not make the finding quoted in the request. As stated in the news release cited in the request (ICC News Release dated 6/8/2000), the ICC hired Liberty Consulting Group to investigate Commonwealth Edison's transmission and distribution systems. The consultants, not the ICC, made the statement quoted in the request. The consultants' report was an independent report and was not adopted by the ICC.

e. Dr. McDermott has not undertaken a specific analysis of Commonwealth Edison's investments in its distribution system, or what measures the ICC took over a ten-year period to monitor such investments. Thus, he is without sufficient information to support or deny the statement in the question. However, Dr. McDermott did participate in a ratemaking docket involving Commonwealth Edison in which the ICC examined an audit report by Liberty that concluded that certain capital additions made by Commonwealth Edison in 1999-2000 should have been made in 1993-1998. In that docket, the ICC concluded that the evidence presented in Liberty's report was "not sufficient to overcome Commonwealth Edison's showing that the distribution capital investment decisions made by Commonwealth Edison in 1993-1998 were reasonable taking into account the facts that were available at the time." *See* Final Order, ICC Docket No. 01-0423, at 66 (copy attached as Exhibit A to Applicants' Response to Request CUB/OEUC 120).

f. To clarify, as stated in the news release cited in the request (ICC News Release dated 7/19/2000), the Liberty Consulting Group found that Commonwealth Edison failed to adopt a recommendation for increased tree trimming. However, Dr. McDermott does not know if this finding was accurate. That said, assuming the accuracy of the consultants' report, Dr. McDermott cannot speculate regarding Commonwealth Edison's reasons for failing to adopt the tree trimming recommendations.

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STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

COMMONWEALTH EDISON COMPANY	:	
	:	
Petition for approval of delivery services tariffs and tariff revisions and of residential delivery services implementation plan, and for approval of certain other amendments and additions to its rates, terms, and conditions.	: : : :	No. 01-0423

Phase II Direct Testimony of

KARL A. MCDERMOTT, PH.D.

Vice President
National Economic Research Associates

ComE Ex. 102.0

Q. Please state your name.

A. My name is Dr. Karl McDermott. I am a Vice President of National Economic Research Associates, Inc. ("NERA"). My business address is 875 North Michigan Avenue, Suite 3650, Chicago, Illinois 60611.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review the methodology employed by the Liberty Consulting Group ("Liberty") in its *Audit of Commonwealth Edison T&D Revenue Requirements: Final Report* ("Liberty Report"), dated October 4, 2002, which addresses certain portions of Commonwealth Edison Company's ("ComEd") distribution investment and operation and maintenance ("O&M") costs. My review will focus on the methodology Liberty uses to propose significant disallowances of capital and O&M expenses in the context of ComEd's 2001 delivery services rate case.

Q. How have you approached this case?

A. My approach to this case has been to review the Liberty Report and Liberty's responses to data requests to determine whether Liberty used proper and understandable analyses that are consistent with recognized Illinois standards concerning prudence reviews of utility conduct in the context of a rate case.

Q. Please summarize your conclusions.

A. I have concluded that the methodologies Liberty employs do not conform to Illinois Commerce Commission ("ICC" or "Commission") precedent on prudence reviews and are inconsistent with proper ratemaking. These conclusions are based on the fact that Liberty does not apply the Illinois prudence standard correctly and makes serious errors in applying established ratemaking standards. Liberty's most grievous errors can be summarized as follows:

- Rather than focus on ComEd decision making based upon facts available to ComEd management at the time, as is required in a proper prudence evaluation, Liberty relies heavily upon after-the-fact statements made after the 1999 outages that have the benefit of hindsight.
- The methodologies Liberty employs are subjective, arbitrary, and incomplete and therefore call into question Liberty's conclusions. For example, Liberty uses a theoretical "trend-line" to suggest its largest O&M disallowance and confuses the proper review of capital expenditures by applying a "normalization" procedure, which fundamentally fails to consider the prudence of specific decisions. This approach is inconsistent with prior Commission precedent.
- As its largest capital disallowance, Liberty calculates only a portion of the costs of delayed investment and does not recognize the time value of money.
- Finally, Liberty fails to make the required causal connection between the dollar amounts of its largest recommended disallowances and any improper conduct on the part of ComEd.

Given these serious errors, I conclude that the disallowances discussed in this testimony are based upon improper analysis and should not be adopted by the Commission.

Q. Please state your qualifications.

A. In my current position, I provide advice and analysis to firms, governments, and other organizations in the U.S. and abroad on business and regulatory issues in the natural gas, electric, and telecommunications industries. From April 1992 until May 1998, I served as a Commissioner of the ICC. Prior to that, I was founder, and served as the President, of the Center for Regulatory Studies ("CRS"), a not-for-profit research organization located on the campus of Illinois State University. I was also a member of the ICC Staff where I worked on alternatives to rate-of-return regulation for public utilities in the Policy Analysis and Research Section. In particular, much of my work related to review and analysis of capital additions of electric utilities, specifically nuclear power plants. I have also worked in other capacities related to regulated industries including positions on the staff of the National Regulatory Research Institute and Argonne National Laboratory. I have also taught graduate level regulatory economics, as well as various other economics courses.

I received a B.A. in economics from Indiana University of Pennsylvania, an M.A. in public utility economics from the University of Wyoming, and a Ph.D. in economics from the University of Illinois at Urbana-Champaign. A copy of my Curriculum Vitae is attached as ComEd Exhibit 102.1.

Q. How is your testimony organized?

A. In Section I, I discuss the foundations for public policy consideration in this case, which provide the background for reviewing the audit methodology. Section II provides my discussion of the major flaws contained in the Liberty Report.

I.

PUBLIC POLICY CONSIDERATIONS

Q. Please discuss the underlying concepts for public utility regulation in Illinois.

A. Public utility regulation in Illinois, as elsewhere, is a balancing act that attempts to place the needs of the utility owners and the rights of utility customers in their proper perspective. To meet the needs of utility customers, investor-owned natural monopoly industries invest in specialized, capital-intensive assets that cannot be redeployed to alternative uses except at a loss of value. Because of this inherent exposure, regulatory institutions for such utilities must be highly credible in the eyes of investors. Thus, much of utility regulation is focused on ensuring that both utility customers and utility investors are treated fairly by the regulator. This "doctrine" of fairness is fundamental to the regulatory process.

Q. How does this "fairness doctrine" apply to this case?

A. Fairness requires that any imprudence be demonstrated objectively so that there will not be uncertainty in the market. Evidence of failure to act prudently must be well grounded in law, economics, and public policy. As will be shown later in this testimony, major parts of the approach taken in the Liberty Report violate many of the basic tenets of an appropriate prudence standard under this "fairness" doctrine and under applicable regulatory precedent.

Q. Please state the standard of prudence that is appropriate for this case.

A. The standard of prudence that is appropriate for this case has been defined quite clearly by the Commission:

> "Prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made. In determining whether a judgment was prudently made, only those facts available at the time judgment was exercised can be considered. Hindsight review is impermissible."[1]

The Commission has further defined how imprudence should be reviewed:

> "Imprudence cannot be sustained by substituting one's judgment for that of another. The prudence standard recognizes that reasonable persons can have honest differences of opinion without one or the other necessarily being "imprudent."[2]

Therefore, the first step in a prudence analysis involves an analysis of the facts that are known or should be known by the utility at the time it makes decisions.

[1] *Commonwealth Edison Company*, ICC Docket No. 84-0395 (Order, October 7, 1987), at 35.

[2] *Id* at 34. The Court has noted that a utility cannot be found to be imprudent "where management has directed matters responsibly." *BPI v. Illinois Commerce Commission, 279 Ill. App. 3d 824, 832 (1st Dist.* 1996).

Q. What is the next step?

A. Once a finding of imprudent conduct is made, one must determine whether any increased cost is attributable to the utility's imprudent conduct. This is, in Illinois ratemaking terms, the quantification of an adjustment to a utility revenue requirement. In other words, in order for an adjustment to be proper, there must be some resulting harm. If a utility was imprudent, but that imprudence caused no harm, *i.e.*, no increased cost, no adjustment to the revenue requirement would be warranted. In sum, the utility should not be allowed to recover through rates the increased costs that it incurred due to its own imprudent conduct.

Q. What are the basic tenets that should be followed in a rate case when evaluating the conduct of utility management?

A. The basic tenets are as follows:

- *20/20 hindsight is inappropriate.*[3] The inquiry should be whether the decisions at the time they were made were reasonable under the circumstances, not based on hindsight. This is, of course, a difficult trap to avoid because rate cases using historical test years are inherently retrospective in that the investments have usually already been made (or will be made during the test year) and the utility is seeking inclusion of those costs in the revenue requirement. This makes it very difficult for a review to avoid being influenced by hindsight as the after-the-fact results are well known. "Results-oriented" analyses are simply impermissible.

- *Eschew hypothetical ideals.* Utilities should be held to an appropriate standard of reasonableness and not to a hypothetical ideal. Since hypothetical ideals can never be attained, such concepts can lead to inappropriate "second-guessing" of utility judgment by substituting the analyst's hypothetical for the manager's judgment. For example, the use of theoretical trend lines as a hypothetically correct benchmark for capital and O&M expenditures would be an unreasonable standard.

[3] *Commonwealth Edison Company*, ICC Docket No. 84-0395 (Order, October 7, 1987).

- *Careful economic analysis is needed.* Audit methodology must recognize both costs and benefits of particular actions and those actions not taken, to obtain a "net" cost (or benefit) of actions actually taken. A proper analysis compares the outcomes under the scenario that *was* chosen, with the results that *might otherwise* have been produced if another scenario had been chosen.[4] For example, Liberty's analysis suggests that investment should have been transferred to earlier periods but fails to recognize the impacts of those transfers on costs and rates.

- *Excessive disallowance for the purpose of "punishing" a utility is inappropriate and can create perverse incentives.* In *CILCO*, a gas rate case involving an Illinois utility, one of the key issues that the Commission decided was the quantification of an adjustment to CILCO's rate base concerning its capital investment in a large gas distribution system. The Commission found that CILCO imprudently delayed installation of the system.[5] The City of Springfield argued that virtually the entire investment in the system should be disallowed in order to send a "signal" to other utilities not to act as negligently as CILCO. The Commission rejected this argument stating,

> "… refusing to place at least a portion of CILCO's investment into rate base would likely cause companies who discover a dangerous situation to put off renewal even longer and to attempt to continue repairing the system even when that approach is, perhaps, not the most economical."[6]

The Commission then said that there must be a causal connection between the imprudence and increased costs.

> "Here, the Commission concludes that the disallowances should be imposed only to the extent that the expenses and investment exceed the levels that would have been incurred absent imprudence on the part of CILCO."[7]

In this case, one of the fundamental problems in Liberty's analysis is that it fails to explain a causal connection between the dollar amounts of its most significant proposed adjustments and any ComEd imprudence. To accept Liberty's adjustments

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[4] *See e.g., Central Illinois Light Company*, Docket No. 94-0040 (Order, December 12, 1994) ("*CILCO*"). The Commission noted that "disallowances should be imposed only to the extent that the expenses and investment exceed the levels that would have been incurred absent imprudence on the part of CILCO." (*CILCO* at p.17).

[5] *Id.* at 24.

[6] *Id.* at 17.

[7] *Id.*

would ignore the “but for” analysis that is central to a legitimate prudence disallowance in an Illinois rate case.

Q. You mentioned that imprudence should be demonstrated objectively. Based upon your experience, are there types of analyses that suggest that one is beginning to stray from objectivity?

A. Yes, in my view, as an analysis becomes more subjective, it becomes more arbitrary and therefore lacks the credibility of an appropriate prudence analysis. Examples that suggest a more subjective approach include: (1) lack of attention to detail; (2) a proliferation of quantitative approaches, under the dubious premise that the use of *more methods* – no matter how shaky the foundation for each – provides better evidence; (3) insufficient candor on the part of analysts regarding their failure to apply objective, reproducible standards; and (4) subjective adjustments to the results of empirical analyses. My concern is that subjectivity can open the door to “results-oriented” decision-making that is not based on a proper prudence analysis.

Q. How does use of a more subjective approach negatively affect customers?

A. Subjectivity creates a regulatory atmosphere in which it is very difficult, if not impossible, for a utility to invest in its system with the confidence that such investment will not be excluded from future rates based on an arbitrary application of the prudence standard.

Q. Is subjectivity apparent in Liberty’s analysis?

A. Yes, Liberty’s analysis is subjective in that:

- Liberty applies a “normalization” procedure for collective O&M costs using an arbitrarily selected trend-line that is assumed to be appropriate. This is based partially on the assumption that the 1991 O&M expenditures were reasonable and projected 2004 expenditures will be reasonable. As will be shown below, such assumptions can lead to nearly any result the analyst would like to see for any given utility.[8]

- Liberty's approach to capital additions suffers from a similar flaw to that of its O&M analysis, as will be discussed later in my testimony.

Liberty also improperly assumes that past O&M costs and capital additions are a good proxy for future O&M costs and capital additions, ignoring more recent factors, such as customers' higher service quality expectations that justify increased O&M costs and capital additions.

II.

REVIEW OF THE AUDIT METHODOLOGY

A. Review of Audit Method

Q. What standards for proposing adjustments to ComEd's revenue requirement does Liberty utilize?

A. In its audit report Liberty suggests that adjustments are appropriate if the costs were imprudent or outside the realm of "normalcy." That is, Liberty will propose an adjustment to DST rates if costs do not meet either of these standards. Liberty states, "[t]he 'normalcy' of costs, regardless of the prudence or reasonableness of their expenditure was also an issue in determining the appropriateness of considering them in making DST rates."[9]

[8] Liberty also excludes cost data for 1998-1999 in the 1991-1997 average on the grounds that "as is apparent from the graph … expenditures in those years were not consistent with the relatively consistent level seen in the 1991-1997 period." Apparently Liberty used a visual method to exclude those costs with no additional analysis to verify that this simplistic procedure was appropriate. *See* Liberty Response to ComEd Data Request No. 3.66.

[9] Liberty Report at I-35.

Q. Does Liberty propose to utilize these standards to adjust rates?

A. It is unclear exactly how Liberty applied the standards. For example, Liberty notes in a data request response that it "'removed' all … costs as part of its general audit mission to segregate all costs that fail either standard [prudence or normalcy]."[10] However, Liberty goes on to state, "… that analytical simplicity should not … be construed as an argument by Liberty about the ratemaking treatment of costs that meet the first standard [prudence] but fail the second one [normalcy]."[11] In fact, in its response to the same data request, Liberty seems to imply that it may have utilized standards other than prudence or normalcy. Liberty states, "[i]n brief, Liberty believes that its role was to identify costs associated with those issues that framed the scope of its audit. That identification included both costs that failed to meet prudence (or similar) standards and that failed to meet the standard of being typical of a normal year of operations."[12]

B. <u>Summary of Conclusions Concerning Liberty's Methodology</u>

Q. Please summarize your conclusions concerning the methodology Liberty used to recommend adjustments to ComEd's revenue requirement.

A. I limited my analysis to the most significant O&M and rate-base adjustments proposed by Liberty. Proper prudence-related calculations involve a careful reconstruction of construction costs and investments to reflect an accurate comparison between actual outcome and "but-for-the-alleged-harm" outcome. Doing so would require a careful cost/benefit study. Liberty generally fails to do this.

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[10] Liberty's Response to ComEd Data Request No. 2.75(a).

[11] *Id*.

[12] *Id*.

Whether or not Liberty has uncovered evidence of imprudence is quite a different question from utilizing the calculations in the Liberty Report to adjust ComEd's revenue requirement. Because the audit methodologies are in large part arbitrary, the key findings and conclusions lack credibility and are not useful for adjusting rates.

Even if the Commission believes that ComEd has been imprudent, using the quantifications suggested by Liberty to adjust ComEd's revenue requirement would violate a standard precept of regulation – that Commission decisions be based on specific facts and not arbitrary methodologies. Examples of fundamental problems with the Liberty Report include:

- *Liberty's trend-line analyses do not support a valid quantification of increased costs caused by any ComEd imprudence*. Specifically, Liberty stated that it "determined this adjustment on the basis of an overall analysis of distribution O&M costs and not by the addition of discrete adjustments."[13] It is very common for utilities to have considerable variation in O&M costs and capital additions. The mere fact that any random period of time used to review these costs shows variation from a trend line is not sufficient evidence to show imprudence. As will be shown below, if this standard is applied to a group of other large utilities, multiple disallowances could be proposed simply due to the fact that utility O&M costs vary from year to year. Further, because utility capital investment tends to be cyclical, it appears lumpy when presented on a timeline as Liberty suggests. Thus, such an analysis is also arbitrary because it fails to take into account the economic realities of the capital investment cycle in this industry.

- *Liberty admits (Liberty Report at II-49) that it was unable to conclude that any specific operating costs were imprudently incurred.* ComEd's expenditure program was necessary to provide service to customers in the test year as the Liberty Report concludes. While Liberty argues that ComEd "could have avoided much of these expenses by actions properly taken in earlier years,"[14] Liberty fails to specifically articulate which expenses were imprudent and why, which suggests that the allegation may be results-oriented and/or based on inappropriate 20/20 hindsight.

[13] Liberty Report at II-1.

[14] *Id*. at II-49.

- *While it is necessary to review capital costs and operating expenses on a coordinated basis, the Liberty Report fails to accurately do so.* For example, Liberty suggests that ComEd should have invested substantial sums in the early 1990s, but does not analyze the corresponding effects on O&M of such investments. Investments in capital additions may result in lower O&M costs over time as a result of substituting for labor; alternatively O&M costs may grow in the short term as capital is expanded to serve new load. In addition, with capital additions there is the "lumpy investment" phenomenon, meaning that a utility's capital additions can vary markedly over time. This is why industry experts focus on capital investment life cycles, looking at the reasonableness of a revenue requirement request as a whole.

- *The "evidence" that the Liberty Report provides is far too subjective and is subject to manipulation.* For example, while Liberty admits that ComEd did not undertake distribution O&M activities in 2000 that were unnecessary, it makes highly subjective statements that ComEd could have avoided many of these expenses by actions taken in previous years. Beyond the bare assertion that ComEd's expenditures were "not normal and should not have been required,"[15] Liberty has failed to factually support its proposed disallowance.

Q. Is it reasonable to expect that utilities' distribution O&M costs and capital additions will be higher in some years, without being higher because of imprudence?

A. Yes. Distribution O&M costs and capital additions increase over time because of a number of factors, including growth and customer quality of service expectations.

Q. Have customers' and public officials' expectations changed as a result of Illinois' electric restructuring?

A. Yes, it is reasonable to assume that customers' and public officials' expectations have changed since 1997, when the General Assembly passed the electric utility restructuring legislation. The new law imposes specific requirements on utilities concerning reliability. Again, this does not mean that past expenditures were imprudent, but as a result of changing expectations, future levels of O&M may be quite different from the levels of the recent past.

[15] *Id*. at II-49.

Q. Please comment on Liberty's normalization of O&M costs.

A. As to its largest proposed O&M adjustment, Liberty did not identify or justify a "normal" level of expense for any expense items, or consider how that expense item related to the overall level of expense in the revenue requirement. Rather, Liberty simply aggregated a number of expenses and utilized a trend line. I am not aware of an electric utility rate case in Illinois where rates were adjusted based upon a trend line that aggregates all O&M expenses in the manner that Liberty has done. Further, an additional problem with utilizing this type of "normalizing" process is that the ComEd's past experience may not be representative of current or future conditions. Extrapolating historical data can be very misleading, especially when current or future circumstances will differ from historical circumstances. In this context, an *ad hoc* approach that relies on casual visual observation of an historical trend in distribution O&M costs may yield grossly misleading results.

Q. Please comment on Liberty's use of "normalizing" to suggest a capital disallowance.

A. In my experience, the Commission's practice is to allow the utility's actual original-cost test-year rate base to be used in setting the revenue requirement, absent a specific finding of imprudence or that an asset is not used and useful.[16] Illinois has a long history of making rate base disallowances, if necessary, to address prudence"[17] or "used and

[16] The Liberty Report does not propose any disallowance based on an "unused and unuseful" argument.

[17] In terms of the prudence of utility rate base additions, the Commission has imposed prudence disallowances in a number of cases, based on well-grounded evidence of imprudence. These cases include: (1) disallowance of $24.7 million of Union Electric's jurisdictional investment in the Callaway plant; (2) disallowance of $291.1 million regarding the prudence review of Byron Unit 1; (3) disallowance of $665 million of Illinois Power's share of the Clinton nuclear unit; (4) disallowance of $733 million of costs related to ComEd's Byron Unit 2 and Braidwood Units 1 and 2. In all of these cases, the Commission made specific findings of imprudence, rather than attempting to rely on evidence of "atypicality." *See* Regulatory Research Associates, *Illinois Annual Review*, October 1995, p. 9.

useful"[18] concerns.[19] To my knowledge, the Commission has never made a disallowance of rate base assets based on a "normalcy" standard. The Commission has not recognized the type of "normalization" Liberty suggests for capital disallowances, and it is not appropriate to adjust rate base in this manner. In ratemaking cases, expenses are treated differently from capital expenditures. When using a historical test year (as in this case), a utility's reasonable expenses are included in the revenue requirement dollar for dollar. Expenses tend to fluctuate from year to year for numerous business and external reasons. As such, it may make sense to view expenses in an historical context. In contrast, Illinois has long recognized that a utility is allowed recovery "of" and "on" its rate base, or capital investments. A utility obtains recovery "of" a particular investment through depreciation expense and recovery "on" that investment through a Commission approved rate of return. In order to recover depreciation and a rate of return on a particular asset, the utility must show: 1) that the investment was reasonable in light of information available to the utility at the time the investment was made; and 2) the investment is "used" and "useful," or necessary to the function of serving customers and actually performing that function. Liberty's approach to disallow recovery of and on existing capital investments that are undeniably "used and useful," simply because they were not placed in service in accordance with a theoretical "normalized" trend-line, represents a dramatic departure from past regulatory practice in Illinois.

[18] In a January 1993 decision, the Commission, on remand, found that "used and useful/excess capacity" disallowances were justified with respect to Byron 2, Braidwood 1, and Braidwood 2. The Commission disallowed an equity return on the non-used and non-useful portions of Byron 2 (93 percent useful), Braidwood 1 (21 percent used and useful), and Braidwood 2 (0 percent used and useful). These units were found 100 percent used and useful in a January 1995 decision by the Commission. *Id*. at 9-10.

[19] In addition, Illinois has sometimes "phased in" capital additions to moderate the short-term rate impact, while allowing the utility to defer the "phase in plant" that is not in rate base with an AFUDC-like return. Thus, while the timing of rate increases is moderated, the utility eventually includes its full rate base in its revenue requirement, with compensation for the time-value-of-money effect caused by the phase in. *Id*. at 9-10.

Q. Can the Liberty Report be considered a true prudence review in its main findings?

A. For the most significant findings in the Liberty Report, I would not categorize its approach as a traditional prudence review, based upon my knowledge of past Commission practice. Liberty's approach, at least relating to the proposed adjustments that I analyzed, appears to be more similar to a "management" audit rather than a prudence audit.

Generally, a management audit is aimed at reviewing management actions for the purposes of improving management decision-making and identifying a set of best practices for future use by management. Such a review depends heavily on hindsight, as it is the *result* of the actions that is the focus of such a review. In stark contrast, a prudence audit is not focused on the results of management actions *per se*, but rather focuses on the reasonableness of those actions (taken or not taken) given the information known or available to management *at the time* decisions were made. A prudence review seeks to specifically ignore the results of the actions (*i.e.*, hindsight) and focuses on reviewing the reasonableness of management decision-making.

The distinction between these two types of analyses is critical in the context of a rate case. To hold a utility to a management audit standard for purposes of establishing rates would be fundamentally unfair. In other words, a utility would only be able to recover costs associated with perfect decision making – virtually every bad result (based upon hindsight review) would be grounds for a disallowance. This creates an unreasonably high standard that has never been recognized for ratemaking purposes in Illinois. To impose such a standard would most certainly have a dramatic adverse effect on the Illinois utility industry.

One of the problems with the Liberty Report is that its most significant findings appear to be "results-oriented." For example, the "normalization" procedures that Liberty uses explicitly take advantage of the uncertain and lumpy nature of utility investment to create an artificial "benchmark" by which ComEd's expenditures are compared. Notwithstanding the principle that ComEd is entitled to recovery of all of its *actual* prudent investment and not a "normal" level of investment, this procedure seems explicitly aimed at the result of reducing ComEd's capital accounts for no other reason than the level of expenditure is higher than this artificially created benchmark. Such an approach looks more like a punitive assessment than a careful review of the actual decisions of utility management at the time of investment, as is required under the prudence standard. The Commission has rejected punitive disallowances in *CILCO*, and should do so again in this case.[20]

1. <u>Capital Investments</u>

Q. Please describe the largest adjustment to ComEd's rate base suggested by Liberty.

A. Liberty recommends that ComEd's rate base be reduced by $66.7 million because ComEd invested in capital addition projects in 1999 through 2001 which, according to Liberty, represented a "peak" in capital spending as compared to earlier years. According to Liberty, this peak spending would not have been necessary had the Company invested "consistently" over the years. (Liberty Report at III-74).

Q. How does Liberty quantify the amount of the adjustment?

[20] *See also Commonwealth Edison Company,* Docket No. 84-0395 (Order, October 7, 1987).

A. Liberty prepared a chart depicting ComEd's historical T&D capital spending levels from 1991 through 2001 and its "projected" spending through 2005. (Liberty Report at III-73). Liberty concludes that the chart depicts a "valley" of spending for the period 1993-98 and a "peak" of spending in 1999-2001. Liberty states that it "… believes that ComEd's rates should be based on a scenario under which ComEd is assumed to have invested in the same projects actually built, but on a consistent basis over a long period." (*Id.*).

Liberty then seeks to determine a "normalized" level of capital spending. It determines that the "average" amount of capital spending over an 11-year period (1991-2001) is $529.2 million. This, Liberty contends, is the "normalized" level of capital spending appropriate for ComEd. ComEd's actual capital expenditures exceeded the normalized amount by $36.1 million in 1999 and $234.3 million in 2000. Because the "valley" of apparent under-spending occurred in the 1993-98 years, Liberty divided the 1999 and 2000 peak amounts ($270.4 million) into "six equal portions" and "deflated" the amounts by the Handy-Whitman index over the period. (*Id.* at III-74). Liberty asserts that the rate base would have been $66.7 million less had ComEd made these investments in equal installments over the 1993 through 1998 period.

Q. Does Liberty determine that ComEd's decision-making with respect to capital investments in the 1993-1998 period was imprudent?

A. No. In fact, Liberty states that it "… did not definitely conclude that any given deferral or design change was either prudent or imprudent." (Liberty Report at III-62) Liberty states, "Liberty's over-arching conclusion in this audit, supported by both quantitative and qualitative evidence, is that ComEd under-invested in its T&D system prior to 1999." (*Id.* at III-72). Liberty also says that it did not identify when any particular capital projects should have been commenced, nor did it even quantify the specific "under-investment" by ComEd in any particular years. (Liberty Responses to ComEd Data Request Nos. 2.06, 2.17) Thus, Liberty seems to acknowledge that it simply did not evaluate ComEd decision-making as it related to the particular projects that it says ComEd should have installed earlier. As stated earlier, this is simply an approach that has not been recognized in Illinois as a valid ratemaking analysis.

Q. Do you have any comments about the methodology Liberty uses to establish its "normalized" investment theory?

A. Yes. Its approach is quite subjective. The time period for analysis is internally inconsistent with other time periods analyzed by Liberty for other adjustments and is based upon questionable assumptions. In recommending its largest O&M adjustment as described further below, Liberty considers the period 1991 through 2004 rather than 2005. Its capital adjustment analysis considers a 15 year period (1991 through 2005), yet its determination of a "normal" level of spending considers only an 11 year period (1991 through 2001). In addition, the selection of the start and end dates for establishing "normal" expenditures assumes, with no analysis, that expenditures in those years are reasonable.

The process of "normalizing" asset expenditures[21] and creating a "smoothing" of investment streams contravenes the essence of a prudence review and cannot be supported by any analysis beyond Liberty's bare assertion that smoothing is an appropriate benchmark. Apparently, Liberty would require utilities to make capital investment decisions based on a trend line rather than real-world engineering principles

[21] Liberty Report at III-73.

concerning load, capacity, and other customer needs. This is hardly a sound approach to be embraced by the Commission, particularly in light of the developing competitive market, where a reliable distribution system is a critical component to market development. However, I understand that other ComEd witnesses are addressing issues related to the specific capital additions and the timing of these additions.

Q. Is a disallowance of capital costs reasonable simply because it is alleged that ComEd should have made investments in previous years?

A. Absolutely not. Liberty's analysis is insufficient to show that "ComEd could have avoided much of these expenses by actions properly taken in earlier years."[22] The investment levels themselves tell us nothing about the decisions made concerning that investment.

As I show graphically in ComEd Exhibit 102.2, other utilities' capital additions vary from year to year.[23] This makes sense given the inherent lumpiness of utility plant additions, even in the distribution sector. Liberty's attempt to "normalize" capital additions, by arbitrarily selecting the timeline from 1991 to 2004, contains no information regarding ComEd's management decisions and any alleged increased costs due to those decisions – it is just an arbitrarily drawn line that fails to show anything about the reasonableness of ComEd's capital additions.

Q. Please explain what you mean by the "inherent lumpiness" of plant additions including those in the distribution sector.

[22] Liberty Report at II-59.

[23] Annual Transmission and Distribution Capital Additions as reported in FERC Form 1. Values were deflated using Handy Whitman Index of Electric Utility Construction Costs, with year 2000 as the base year.

A. Utility capital is not adjusted in a smooth and continuous fashion. Capital additions are often put in place to serve both current and future load and may require large single year investments that last many years. This lumpiness phenomenon will often result in large discrete increases in capital additions in one year, while in subsequent years there may be little or no investment until new investment is needed once again.

Q. Liberty argues that ComEd deferred capital projects that it should have been installing. How does ComEd's capital addition experience compare with other large utilities?

A. ComEd's capital addition trend is comparable to the capital addition trend of other large utilities – in other words, there is no basis for arguing that ComEd's actions were inconsistent with the utility industry during the 1990s. ComEd Exhibit 102.2 shows that capital additions for these utilities will vary from year to year. Of course, such a result is not surprising due to the lumpy nature of electric distribution investment. Utilizing this factor to adjust a distribution utility's rate base downward represents an arbitrary adjustment and should be rejected by the Commission.

2. <u>Operations and Maintenance Expenses</u>

Q. Please describe the most significant proposed adjustment to ComEd O&M expenses.

A. Liberty recommends that the Commission reduce ComEd's O&M expenses by $90.3 million. I will describe in more detail below the nature of the adjustment, but in sum, Liberty estimates "a reasonable O&M cost through an overall analysis of costs rather than an itemization of costs and issues." (Liberty Report at II-49) Liberty aggregates the expenses reflected in 19 ComEd FERC accounts (FERC accounts 980 – 998), ($385.2 million (adjusted)). Liberty determines the aggregate expense in those accounts in 1991 ($219.1 million) and the projected expenses in 2004 ($323.6 million) and then draws an imaginary line to connect the 1991 and 2004 amounts – this is the Liberty "trend-line". (*Id.* at II-53). Liberty then determines that in order to get from point "a" (1991) to point "b" (2004) in precise annual increments, expenses would have to increase by 3.045 percent per year. (Liberty response to ComEd Data Request No. 3.089). Using the trend-line, one finds that the imaginary point on the line in 2000 is $287 million. Liberty asserts that this $287 million is the "normalized" year 2000 O&M expense and proposes that ComEd's revenue requirement be reduced by $90.3 million to match the normalized amount.[24] (Liberty Report at II-49)

Q. How does this approach compare with the prudence methodology that you describe earlier in your testimony?

A. As I said before, a proper prudence analysis involves two steps, the first of which its an evaluation of whether ComEd's conduct was reasonable when decisions were made based upon facts that ComEd knew or should have known at the time of the decision. If one determines that ComEd acted unreasonably or imprudently, the next step is to quantify the resulting harm to ratepayers, or the amount by which costs increased as a result of the imprudent conduct. The trend-line is Liberty's quantification.

Q. Please describe the conduct of ComEd that Liberty says justifies this adjustment?

A. Unlike under a traditional prudence analysis, Liberty does not discuss the reasons for discrete expenditures, and therefore fails to describe management decision-making with respect to these expenses. To the contrary, Liberty even acknowledges that "ComEd did

[24] Liberty calculated the total actual charges to FERC accounts 580-598, minus an adjustment for incentive compensation, as $385.2 million for the year 2000. (Liberty Report at II-53). The "normalized" figure is calculated as $287.1 million for that same year. (*Id*.) Liberty notes the difference between its normalized figure and the Interim Order's level of distribution O&M is $70.2 million. Adding this to the adjustment for tree trimming, storm management, and salaries and wages provides a proposed adjustment of $90.3 million. (*Id*. at II-10).

not undertake in 2000 distribution O&M activities that were unnecessary." (Liberty Report at II-49). However, Liberty states that "ComEd could have avoided much of these expenses by actions properly taken in earlier years." Liberty does not specifically explain what "actions" ComEd should have undertaken in earlier years. Instead, Liberty simply cites to self-critical statements that ComEd made in a report drafted after the 1999 outages, "The Blueprint for Change".[25] That document is predominantly a hindsight analysis that ComEd prepared in the wake of the 1999 outages to be used as a tool to make improvements. It is inappropriate for Liberty to cite to it as a substitute for Liberty's own factual analysis of prudence. Therefore, I concluded that Liberty failed to adequately show that, without the benefit of hindsight, ComEd acted imprudently.

Q. Do you have other comments about this adjustment?

A. Yes. Even if one assumes that ComEd was imprudent, Liberty fails to establish any causal connection between the improper conduct and the amount of Liberty's recommended adjustment. Despite saying that all of ComEd's O&M actions in 2000 were necessary, Liberty states that, "ComEd had to spend significant sums in 2000 and that those amounts were not normal and should not have been required." (Liberty Report at II-49). Liberty did not explain which amounts should not have been required. Liberty also does not say that the amount is $90 million.

In addition, the methodology that Liberty employed to quantify this adjustment is highly subjective. Liberty assumes the "reasonableness" of certain expenditures when that assumption fits within its analysis. For example, the costs that form each endpoint on Liberty's trend-line (1991 and 2004) are simply assumed to represent "reasonable"

[25] Liberty Report at II-49.

O&M expenditures.[26] Also, Liberty made no determination that the O&M expenses in each of the years in the trend-line were reasonable.[27] It is simply not reasonable in the real world to assume that O&M expenditures will rise by a certain percentage each year. As one can see on the chart attached as ComEd Exhibit 102.3 to my testimony, the O&M expenditures of a group of large utilities over the last several years vary substantially from year to year.

There are other problems with Liberty's O&M trending approach. Liberty, for example, asserts that "[t]he amount of distribution O&M expenses included in ComEd's test year 2000 was not representative of a normal year of operation." (Liberty Report at II-48). That, however, does not mean that its costs in that year were unreasonable and should not be recovered.

Liberty does not attempt to evaluate whether any specific expenses were necessary. Instead, it simply measures a large portion of expenses against an arbitrary benchmark or trend line that it deems "normal".

Q. How does this adjustment compare with Illinois ratemaking practice?

A. To my knowledge, previous regulatory disallowances have not been made using this approach. Compared with the Liberty, the Commission has traditionally used a far more rigorous quantification of the harm to utility customers resulting from a utility's imprudent actions.

The Liberty Report would arbitrarily "chop off" ComEd's 2000 O&M costs based on its trend-line. But, as shown graphically in ComEd Exhibit 102.3, for a group of large

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[26] (Liberty Response to ComEd Data Requests Nos. 2.24 and 3.021).

[27] (Liberty Response to ComEd Data Request No. 2.04).

utilities, O&M annual distribution expenses vary from year to year, with a number of utilities facing cost increases.[28] Choosing the time frame from 1991 to 2004 and simply drawing a line does not show the causality between alleged imprudent utility management decisions and the "extra" cost proposed to be included in rates. It is simply an arbitrarily drawn line that fails to show anything about the reasonableness of ComEd's O&M costs.

Q. Why is this a critical aspect of the analysis in this case?

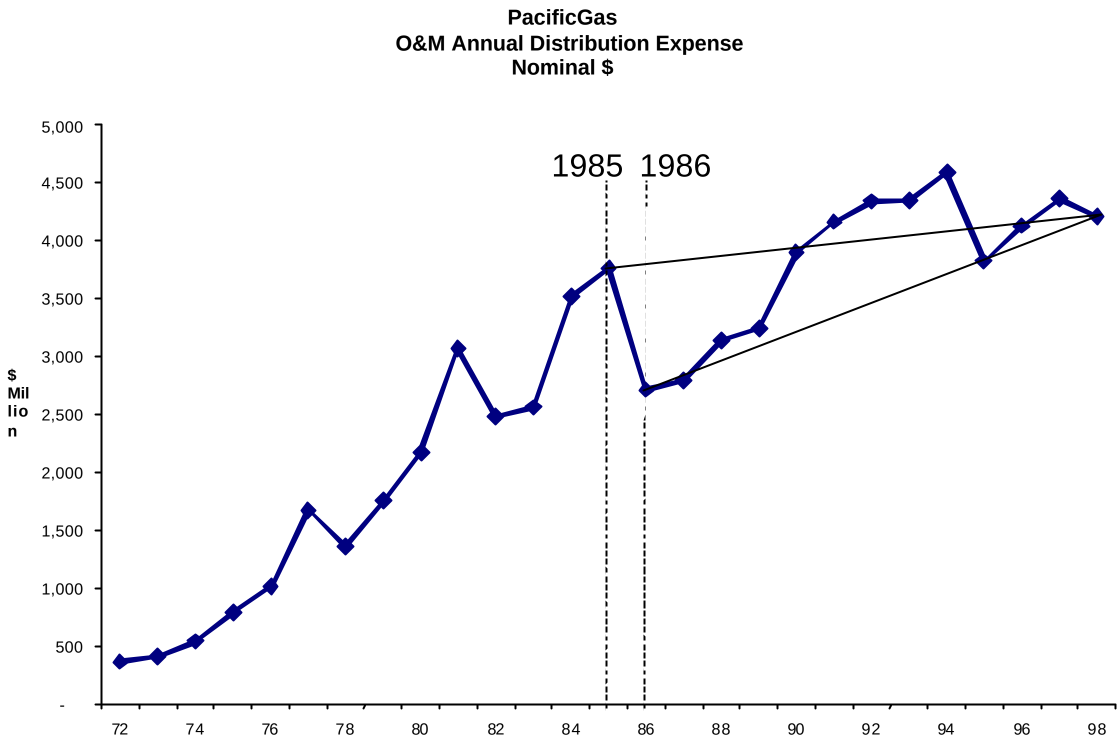
A. The mere variation of costs above an arbitrarily created trend line is simply not evidence that those incremental costs are unreasonable. For the Commission to accept Liberty's trend-line approach, without the necessary connection between imprudent behavior and the cost associated with that imprudent behavior, would set this Commission down a new road of utility rate review that differs radically from the path Illinois has been on. I would suggest that the Commission reject such a radical departure from precedent.

As shown graphically below, Pacific Gas & Electric (PacificGas) provides an indication of the arbitrariness of the choice of a beginning date for a "trend line" analysis. In this illustration, using NERA's FERC Form 1 data base, it is clear that varying the starting point by one year can have a huge impact on the slope of the line, and, therefore, the amount of the disallowance that would result from using an arbitrary trend-line approach.[29] The Liberty Report's starting point for its O&M trend line is inherently

[28] Annual Distribution Operation and Maintenance Expense as reported in FERC Form 1 for each peer group company.

[29] Annual Distribution Operation and Maintenance Expense for peer group companies, as reported in FERC Form 1.

subjective, meaning the analyst can, to a large extent, get the result that he or she wants by manipulating the starting and ending points.[30]



As is graphically illustrated below, using ComEd data for 1972-1998 and drawing lines for 1972 to 1998, 1974 to 1998, etc., picking the starting point can have a major effect on the result. There is no obvious reason why Liberty chose 1991 as the starting point for its O&M trend-line analysis and varying that date would have had a material effect on the amount of the disallowance. Liberty's analysis is inherently subjective and, as such, does not provide a basis for a prudence disallowance.

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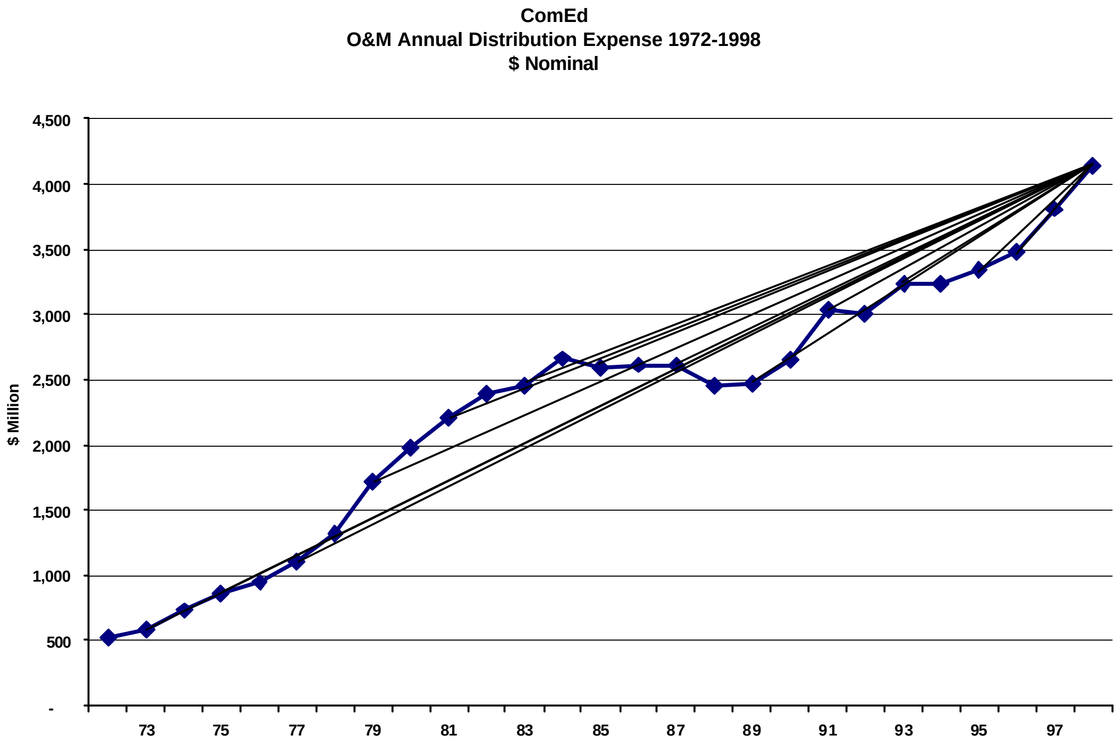
[30] In fact, Liberty does no analysis of the changes in load growth, or the reasons for variation in O&M for the "peer" group utilities. *See* Liberty Response to ComEd Data Requests Nos. 3.94, 3.97, 3.98 and 3.99.



Q. Please summarize your conclusions.

A. In sum, with respect to its largest proposed adjustments, Liberty: 1) fails to provide a legitimate factual basis for an imprudence finding against ComEd; 2) develops methodologies to quantify adjustments that are so subjective that they lack credibility; 3) utilizes techniques that purportedly "normalize" certain expenditures in a way previously unrecognized in Commission practice; and 4) recommends dollar adjustments that bear no causal connection to any conduct of ComEd. To accept the adjustments as proposed by Liberty would signal a fundamental change in ratemaking economics in Illinois.

Q. Does this complete your Phase II direct testimony?

A. Yes.

Commission Staff To U S WEST On New Switches: Put It In Writing

June 3, 1999 (1999-022)

Contacts: Ron Eachus, Chairman, 503 378-6611; Roger Hamilton, Commissioner 503 378-6611; Joan H. Smith, Commissioner, 503 378-6611; Phil Nyegaard, Telecommunications Administrator, 503 378-6436; Ron Karten, Public Information Officer, 503 378-8962

Salem, Ore. – U S WEST Communications, Inc. has declined to commit in writing to new digital switches for the Roseburg, Grants Pass and Albany areas. Staff of the Oregon Public Utility Commission (OPUC) had requested that the company commit to installing the switches by the end of the year 2000. As a result, Commission staff will propose that the Commission order the company to do so at an upcoming public meeting.

"These upgrades are too important for anything less than a solid company commitment," said Phil Nyegaard, Administrator of the Commission's Telecommunications Division. "And that's what we're asking for."

In a May 7 letter to the company, Commission staff said it would accept the company's plan for case-by-case reimbursement for Roseburg area customers who had experienced excessive blocking – instead of a community-wide reimbursement -- if the company would also put in writing its commitment to install the new switches during calendar year 2000.

Staff insisted on a written commitment because, in reports concerning the Commission's investigation of service quality issues in Roseburg, the company said, "U S WEST makes no representation or commitment – either expressed or implied – that the construction projects submitted to the commission will, in fact, be completed."

In declining to provide a written commitment, the company cited the possibility of changing priorities, unpredictable suppliers, and the difficulties of scheduling technicians.

"If the company has done the work of scheduling the upgrades and the supplier does not come through, that is something the Commission understands and can make allowances for," said Nyegaard. "But if the company simply changes its mind, that is something the Commission would take exception to."

The Commission has been disappointed in recent years that the company has failed to make commitments that would lead to improved service quality. In 1996, the Commission granted the company $14 million worth of accelerated depreciation based on the company's plans to replace the analog switches with digital switches. The company has yet to do the work.

Since November of last year, U S WEST customers in Roseburg have complained about poor service throughout the community. Formal complaints about the company's service were filed at the Commission from an area hospital, state and local police units and the U S Forest Service. The hospital and police complaints were potentially life-threatening.

At an April 8 public meeting in Roseburg sponsored by the Commission, service complaints came from companies as large as Roseburg Forest Products, an international wood products and information technology company, and from single residential customers noting that they were unable to reach 911 in an emergency. Companies reported on business losses due to generally clogged telephone lines and U S WEST's failure to provide specifically needed facilities.

As a temporary measure in the wake of that outcry, the company updated the analog switch in the Roseburg area and promised to replace it with a more functional digital switch by the end of 2000 rather than waiting until 2003, as it had said it would during the Roseburg public meeting.

The Commission believes that earlier upgrades would have prevented on-going and anticipated problems experienced throughout the Roseburg, Grants Pass and Albany areas. Still, the company declined to provide a written commitment to install the switches, citing the possibility of changing priorities, unpredictable suppliers, and the difficulties of scheduling technicians.

Meanwhile, the Commission intends to proceed with developing an expedited process for providing billing credits to U S WEST customers in Roseburg who have had blockage problems.

-30-

II
ADDRESSING THE 511 STANDARD AND ISSUES FOR THIS APPLICATION

PGE's customers will be better off with the merger of PGC and Enron because of:

- ✦ Our commitment to achieve at least $3 million per year in PGE cost of service reductions through administrative consolidation and application of Enron's expertise to PGE's operations and to adopt the current Master Services Agreement between PGC and PGE to govern services between Enron and PGE unless and until we propose and the Commission approves a new agreement

- ✦ Our entrepreneurial attitude, culture and successful experience

- ✦ Our commitment to isolate PGE's franchise customers from the risks of non-utility enterprises

- ✦ Our commitment to absorb at Enron and PGC all merger transaction costs

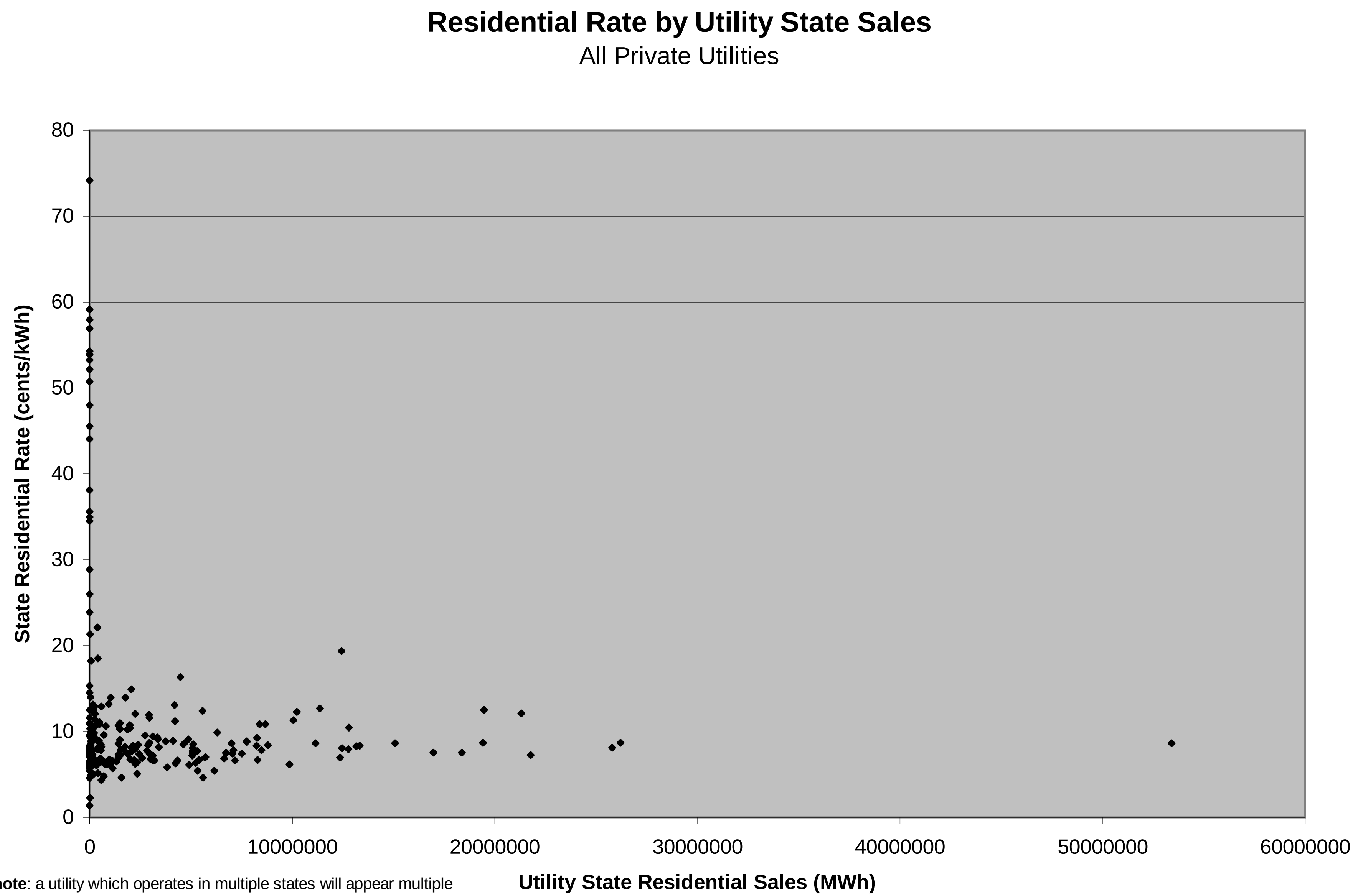
- ✦ Our willingness to abide by all state and federal rules relating to approval and reporting of intercompany charges and prevention of cross-subsidization and affiliate abuse

- ✦ Our willingness to accept conditions designed to ensure that the merger does not increase PGE's cost of capital

- ✦ The lack of any effect of the merger on property sales, the Residential Exchange, PGE contractual commitments, other PGE commitments, and intercorporate employee transfers

Cost of Service Savings. Once our merger with PGC is complete, we believe that we will be able to realize reductions in PGE's cost of service. Some of these reductions will come from applying Enron's expertise to PGE's operations. Other savings will come from administrative consolidation.

Despite the difficulty of quantifying prospective cost of service savings, we are



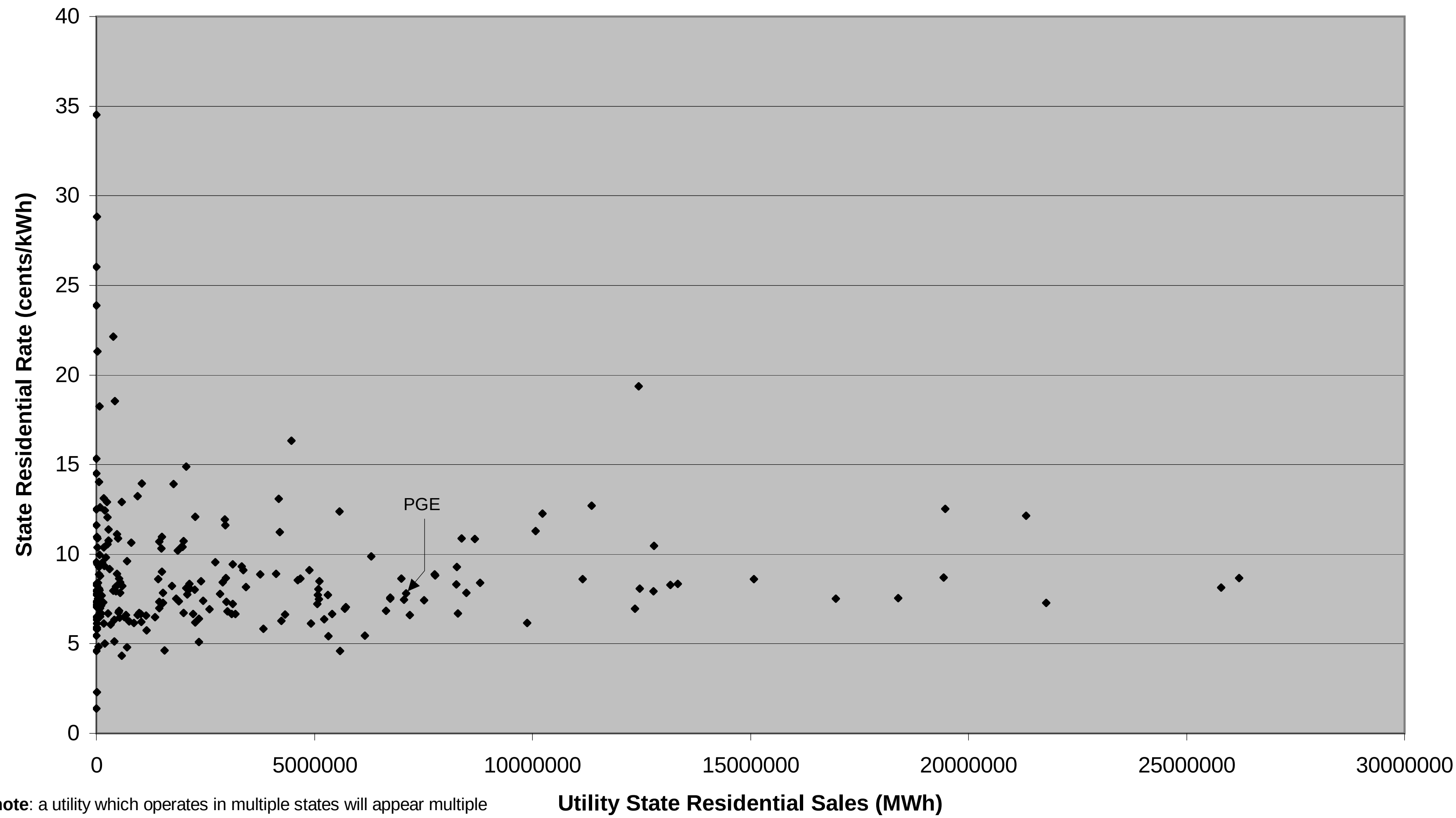
note: a utility which operates in multiple states will appear multiple times on the graph, and rate and sales are specific to each state

CUB/323
Jenks-Brown/1

Residential Rates by Utility State Sales

Private Utilities

Removed: FPL for size, all rates 35 and above



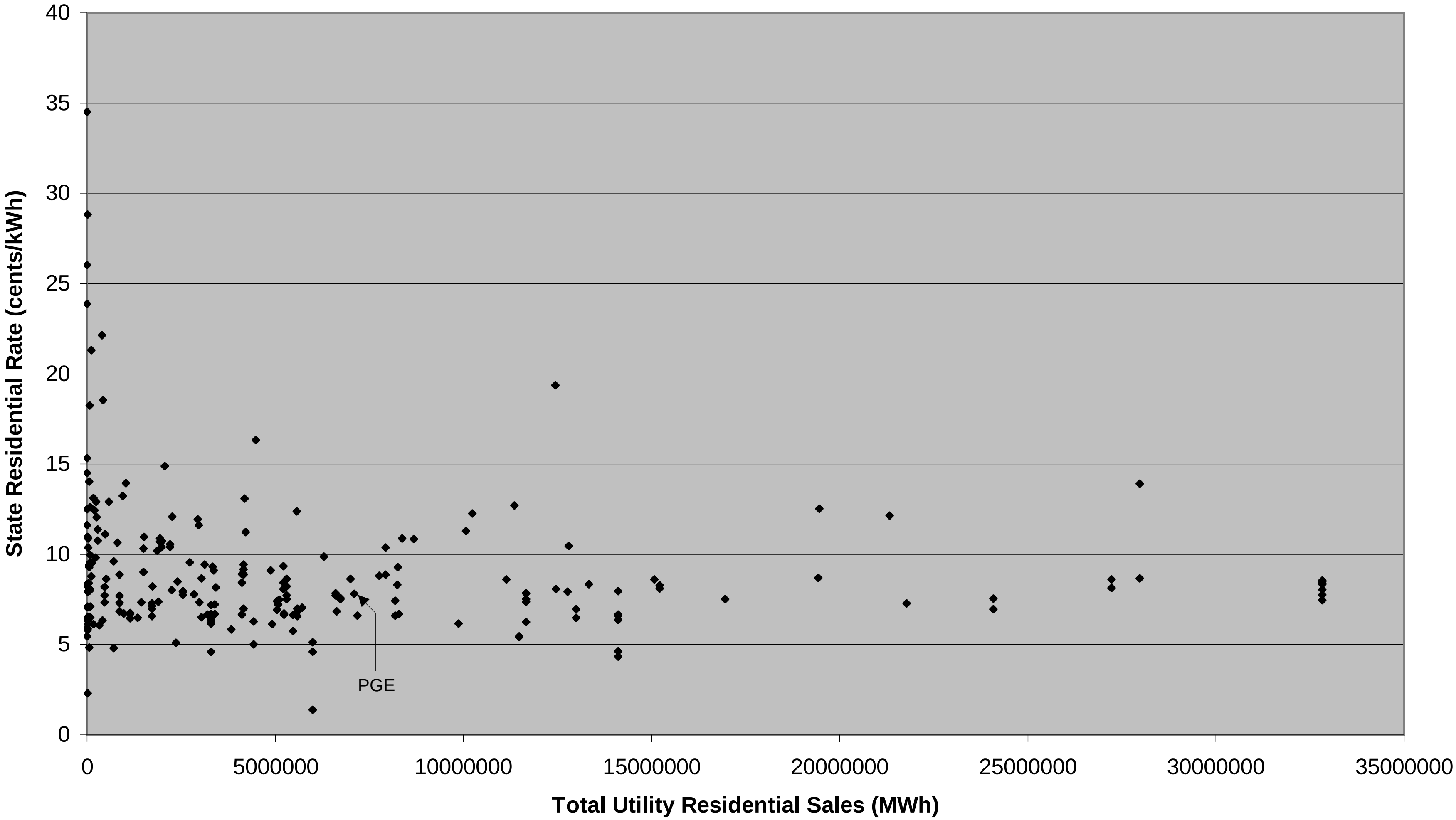
note: a utility which operates in multiple states will appear multiple times on the graph, and rate and sales are specific to each state

CUB/323
Jenks-Brown/2

Residential Rates by Utility Sales

Private Utilities

Removed: FPL for size, all rates 35 and above



CUB/323
Jenks-Brown/3

The Oregonian

Not Enron is not enough

The company bidding for Portland General Electric must demonstrate that there's more in the deal for ratepayers

Monday, July 26, 2004

The staff of the Oregon Public Utility Commission went looking for a net public benefit in Texas Pacific Group's $2.35 billion bid for Portland General Electric, and, predictably, didn't find it.

It's not there. Not yet. The serious back-and-forth negotiations between Texas Pacific and the Oregon commission are just now beginning. State regulators were sure to object to the company's first purchase plan. Texas Pacific is sure to sweeten its offer.

That's how the regulatory process works. But while the PUC staff is right to look for public benefit in the deal, they may be looking in the wrong place.

In prior megadeals involving Oregon utilities, including Enron's original purchase of PGE, the PUC demanded rate credits to provide a public benefit. But over the next few years PGE, saddled with the costs of mothballing the Trojan Nuclear Plant and other liabilities, is more likely to raise rates than lower them. Even though PGE has some of the highest residential rates in the Northwest, any potential buyer, including the city of Portland, would be hard-pressed to cut them.

Even if the public utility commission manages to squeeze a token amount of rate credits out of Texas Pacific, typical ratepayers wouldn't even notice a difference on their monthly bills.

Texas Pacific has outlined a list of potential public benefits in its purchase plan, but they boil down to removing PGE from Enron's sleazy grip. The company argues that restoring stability to the local utility, as well as providing local influence on a board of prominent Oregonians, is a major public benefit.

The only rate relief Texas Pacific has offered so far is a shallow promise to provide an unspecified level of rate credits if annual profits exceed the 10.5 percent return allowed by regulators. But if the company's profits top that level, the public utility commission almost certainly would require the company to return money to ratepayers.

Regulators and ratepayer advocacy groups are right to demand more. The Citizens' Utility Board and Industrial Customers of Northwest Utilities, which represent residential and business ratepayers, are less interested in token rate credits than securing the future of PGE.

Texas Pacific is a private equity firm that generally holds its investments for five to seven years. Bob Jenks, executive director of the Citizens' Utility Board, argues that state regulators should require the company to lay out how it would eventually sell PGE. Jenks has suggested that a public entity have a right of first refusal.

Texas Pacific will balk at any requirement that limits the eventual value of PGE. If the company walks away, or if the PUC rejects this deal, PGE's stock will be distributed to Enron's creditors and sold into the market.

That scenario would lead to several more years of drift and uncertainty, in a business badly needing strong leadership and long-term strategic planning. It's hard to see how PGE's rates go down in this scenario, either.

If possible, Oregon regulators should build into the Texas Pacific deal incentives for PGE's eventual return what it was -- a well-run, investor-owned, stand-alone utility headquartered in Portland. If that happens, no one will have to search for the public benefit.

CUB Proposed Conditions

CUB 1. If TPG/OEUC does not dispose of PGE through one or more public offerings of PGE's stock, then, nine months before it initiates any bilateral arrangement to sell PGE, including a public auction, it will provide notice to the City of Portland, which may then initiate action for the purchase of all PGE's assets located in Oregon and outside the state. Within ninety days from PGE's notification, the City Council will indicate the City's interest in purchasing PGE's assets by adoption of an ordinance.

In the event that the City Council adopts such an ordinance, the value of the assets will be determined through an arbitration panel consisting of three arbitrators. A decision of the arbitration panel will be final and binding as to the valuation of PGE assets. The City Council and TPG will each appoint an arbitrator, and those two arbitrators will then attempt to agree on a third member. If the two arbitrators can not agree upon a third member, then the arbitrator will be appointed by the Presiding Judge of the Circuit Court of the State of Oregon for the County of Multnomah. The arbitration panel will conduct a hearing and will render a decision within sixty days of conducting the hearing. The arbitration proceeding shall be conducted according to the procedures set forth in the Uniform Arbitration Act under ORS 36.300 through 36.740.

After issuance of the arbitration panel's determination, the City will promptly decide whether to take steps to further the purchase of PGE assets at that price, and if it does decide to proceed, it will promptly arrange financing in such a manner as the City deems best.

The City may transfer or assign this option to a consortium of units of local government, whether organized under ORS Chapter 190 or some other organizing principle, if the consortium of local units of government is representative of at least 50% of PGE customers. Or the City may exercise this Option to Purchase if the City Council previously adopts a governance plan that is generally representative of PGE's service territory.

CUB 2. OEUC and PGE will support the intent and direction of SB 1149, including the investments in energy efficiency and renewables through the Energy Trust of Oregon. OEUC and PGE commit to communicate, confer, and work in good faith with the SB 1149 stakeholders, including the Commission, CUB, ICNU, AOI, and the Fair and Clean Energy Coalition to further implement and refine the energy policies reflected in SB 1149, including the investments in energy efficiency and renewables through the Energy Trust of Oregon.

CUB 3. With its annual Results of Operations, PGE will provide a copy of its current organizational chart.

CUB 4. Until such time that Oregon Electric's bonds are investment grade and equally rated with PGE's bonds, any new long term debt or preferred stock issuances will be reflected for ratemaking purposes at a cost rate at the time of issuance that is one notch above the actual rating granted by the rating agencies.

CUB 5. PGE agrees to reflect the additional interest deduction at the Oregon Electric parent company level in order that income taxes being recovered, for ratemaking purposes, through PGE retail rates more closely approximates the taxes actually being paid by Oregon Electric to federal and state taxing authorities.

CUB 6. At the time of its next general rate filing, PGE will provide testimony demonstrating that it is not proposing higher costs in each of the functional areas formerly provided by Enron than what customers paid during the average of Enron's last three years of ownership.

CUB 7. Oregon Electric will prepare and make available to the Commission and the public, on a quarterly and annual basis, financial and operating disclosure reports that are equivalent in scope, content, and format to that of Form 10-Q and Form 10-K reports filed with the U.S. Securities and Exchange Commission.

CUB 8. OEUC and PGE will make annual informational presentations to the Commission regarding PGE's construction expenditures and O&M expenses. The presentation will provide construction expenditure and O&M expense annual budgets and compare past budgets with actual annual expenditures and expenses. The presentation will also provide a rolling three-year average of construction expenditure and O&M expenses.

CUB 9. As directed by the Commission, PGE will pay for a management and operations audit by an independent outside auditor. The independent auditor will be selected by Staff with input from ICNU, CUB and other interested parties. The Staff with input from other parties will prepare a scope of work. The scope of the audit could include a focus on strategic and operational planning, budgeting, capital expenditures, O&M expenditures, measures of work planned and performed, maintenance planning, performance and backlogs, performance measurements, and the organizational and management structure and the adequacy of personnel performance measures. During the ownership of PGE by OEUC, there is no limit to the number of directed management audits, however no more than one audit will be initiated with in a two year period. If an audit is limited in scope and addresses a particular utility function, this provision does not preclude an additional audit on a different utility function within the two-year window.

CUB 10. If the Commission, in response to the independent auditor report, orders PGE to adjust its budget in a particular area of operations or for a particular investment, or orders PGE to make a direct investment, PGE agrees to comply with that order.

CUB 11. TPG will maintain and the Commission shall have unrestricted access to all books and records of TPG that are reasonably calculated to lead to information relating to PGE.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

UM 1121

In the Matter of the Application of OREGON	)
ELECTRIC UTILITY COMPANY, LLC, TPG	)
PARTNERS, III, L.P., TPG PARTNERS IV, L.P.,	)
MANAGING MEMBER LLC, NEIL	)
GOLDSCHMIDT, GERALD GRINSTEIN, and	)
TOM WALSH for an Order Authorizing Oregon	)
Electric Utility Company, LLC to Acquire	)
Portland General Electric Company	)
	)
	)

SURREBUTTAL TESTIMONY OF JAMES R. DITTMER

On Behalf of the
Citizens' Utility Board of Oregon

September 2004

Q. Please state your name and address.

A. My name is James R. Dittmer. My business address is 740 Northwest Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. Have you previously filed testimony in case?

A. On July 21, 2004 I submitted opening testimony in this case on behalf of the Citizens' Utility Board ("CUB").

Q. On whose behalf are you presenting surrebuttal testimony?

A. Like my opening testimony, this surrebuttal testimony is also being submitted on behalf of CUB.

Q. What is the purpose of your testimony?

A. On August 16, 2004, Oregon Electric Utility Company (hereinafter "Oregon Electric") filed rebuttal testimony to the direct testimony filed by various CUB witnesses, the Oregon Public Utilities Commission ("OPUC" or "Commission"), as well as a number of other intervenors. The purpose of this surrebuttal is to respond to a limited number of comments or issues addressed in such Oregon Electric rebuttal testimony. Specifically, I will be addressing the dismissal by Dr. McDermott and Mr. Kevin Davis of Staff and intervening parties' concerns over the risks associated with the highly leveraged Oregon Electric consolidated capital structure. I will also address Dr. McDermott's and Messrs. Tinker, Murray and Hager's testimony regarding the appropriate rate treatment to be afforded consolidated tax savings. Additionally, I will address Mr. James Piro's testimony regarding the ability – or inability – to quantify capital cost implications resulting from the double leveraged capital structure. Finally, I will briefly address Messrs. Tinker, Murray and Hager's testimony which dismisses a recommendation which I made in my opening testimony to have the Company track incremental costs incurred by Portland General Electric (hereinafter "PGE" or "Company") to replace charges previously paid to Enron for corporate governance services rendered.

Q. Please continue by summarizing the first element of Oregon Electric's rebuttal testimony that you would like to address.

A. Several Oregon Electric rebuttal witnesses dismiss the "uncertainty" and "risk" factors claimed by many Staff, Cub and other intervenor witnesses to be a detriment from the proposed transaction that will result from the more highly/double leveraged capital structure. Mr. Kelvin Davis states that "PGE's customers are not responsible for Oregon Electric's debt – this debt is the risk of Oregon Electric's equity investors." (Davis Rebuttal, page 3). Dr. Karl McDermott claims Staff and Intervenors are one-sided in their analysis of benefits and risks. Dr. McDermott further claims "[t]he bogeyman of uncertainty and risk can be invoked in any transaction." (Dr. Karl McDermott, rebuttal page 24)

Q. Is the claimed risk and uncertainty associated with the double leveraged capital structure espoused by various intervenor and Staff witnesses something that has been dreamed up for this case?

A. No. Those associated with Oregon Electric may desire to paint Staff and Intervenors' position on this issue as a collective one-sided argument that has been dreamed up for purposes of this case. However, what cannot be denied is that the various rating agencies of PGE and Oregon Electric's debt share this exact same concern. I will not reiterate my opening testimony on this issue, but will incorporate by reference herein, that portion of my opening testimony wherein I discuss how PGE's debt ratings – even with ring-fencing measures – will be viewed cautiously by the various rating agencies. It should be remembered that while Oregon Electric may attempt to persuade this Commission that its Staff and Intervenors' are not objective in their assessment of risk stemming from the transaction, they have apparently not been able to convince independent rating agencies that such fears are totally misplaced. In summary on this point, notwithstanding the volumes of rebuttal testimony, this Commission should not dismiss the risks and uncertainty that would accompany the proposed transaction – just as independent rating agencies have not been fully persuaded by such arguments.

Q. Please continue by briefly describing the next element of Oregon Electric's rebuttal testimony with which you take exception.

A. Several intervenor parties argued in direct testimony that it would be appropriate to consider within the development of PGE's retail rates the income tax savings that will be resulting from the Oregon Electric/PGE double leveraged capital structure. Dr. Mc Dermott as well as Messrs. Tinker, Murray and Hager have argued against such rate making treatment. Specifically, Dr. McDermott discusses the fairness of only charging customers for costs incurred in the provision of utility service. He expands upon how, under the traditional regulatory paradigm, ratepayers should be protected from being charged for costs or losses incurred for any non-utility activities. Conversely, he argues that it would be unfair for utility ratepayers to be charged for less income tax expense than a utility would otherwise incur on a stand-alone basis by virtue of, or as a result of, an affiliate's losses or costs.

Additionally, Messrs. Tinker, Murray and Hager describe how this Commission has recently rejected a purportedly similar argument in Order No.03-214. Specifically, in the noted order the OPUC rejected a petition of the Utility Reform Project to initiate an investigation as to whether income taxes paid to PGE since 1997 – or the time that Enron acquired PGE – should be refunded to ratepayers. Messrs. Tinker, Murray and Hager further quote a Staff memo from that case wherein Staff elaborates upon how, if PGE's rates were to be set so as to capture some of Enron's tax losses, that such rates would also have to be adjusted so as to reflect the Enron expenses that created such losses.

Q. How do you respond to such Oregon Electric/PGE rebuttal points?

A. First, I would note that I am in conceptual agreement with the points made. Specifically, I have never advocated incorporating tax savings stemming from affiliate or parent company losses that have resulted from forays into unsuccessful non-utility business ventures. I agree with the Staff memo quoted by Messrs. Tinker, Murray and Hager wherein Staff counsel advised that "it would be difficult for the

OPUC to justify picking and choosing which of Enron's revenues and expenses – including tax savings – to include for purposes of setting Oregon customers' rates."

While *conceptually* agreeing with arguments made by Dr. McDermott as well as Messrs. Tinker, Murray and Hager, I disagree that the facts that present themselves in this case are identical to the scenarios being addressed by Dr. McDermott and Messrs. Tinker, Murray and Hager. Specifically, the question before this Commission is whether the tax deduction stemming from Oregon Electric interest expense should be considered in the development of PGE's cost of service income tax expense development. The majority of interest expense paid on the Oregon Electric debt will be incurred in support of PGE's utility assets. PGE ratepayers will be expected to pay such interest cost directly if PGE is regulated by employment of an Oregon Electric consolidated capital structure – or indirectly, if PGE is regulated with a stand-alone capital structure. Under the latter scenario, even if PGE rates were to be established by considering PGE's stand-alone and more equity-rich capital structure, such rates would nonetheless still undeniably be designed to pay the interest cost on Oregon Electric's debt. Either way, PGE's rates are expected to be established so as to cover the interest cost associated with Oregon Electric's debt that is ultimately supporting PGE utility assets. Thus, the scenario being addressed in this case is factually different than merely grabbing tax savings from parent or affiliates that are generated from activities that are unrelated to provision of utility service. Or in other words, the crediting of Oregon Electric's interest deduction – an interest payment envisioned to be paid directly or indirectly by PGE ratepayers – is far different than simply considering parent/affiliates' tax losses in cost of service income tax development *regardless of origin*.

Q. Please continue by discussing the next area of the Company's rebuttal testimony that you wish to address.

A. Mr. James Piro addresses in his rebuttal testimony how the rating of a given company's securities is both subjective and imprecise. He goes into some detail describing how rating agencies look at a number of factors or events in arriving at an ultimate rating. At page 17 of his rebuttal testimony Mr. Piro states:

> Since many factors are considered when assigning bond ratings, one cannot conclude that changing any one factor discussed in a rating release would automatically result in a change in ratings. Indeed, contained in the occasional multi-year gaps between changes in PGE's ratings are numerous events and circumstances that differ from those described in the original rating release. These changing events and circumstances could potentially have changed the rating if other events and circumstances had not also changed. In other words, the credit rating represents the overall aggregation of information on all aspects of the company and is not predicated on any single event.

On page 18 of his rebuttal Mr. Piro discusses a number of positive as well as negative events that affected PGE in the 2002-2003 time frame. He basically concludes that one single event may not trigger a rating change, and that it is virtually impossible to know how much any one single event affects a rating change inasmuch as it is the aggregation of *all events* that would cause a change in a rating.

Finally, he concludes that the relationship between a firm's credit rating and the cost it pays for a particular debt issuance is even more tenuous. (Piro rebuttal, page 21)

Q. How do you respond to the opinions of Mr. Piro that you discuss above?

A. It would appear that the Company is already posturing to claim that either 1) any increase in cost of capital – be it debt or equity – cannot be associated with the more highly double leveraged capital structure resulting from the transaction or 2) it is simply impossible to determine whether any increase in capital costs can be attributed to the double leveraged capital structure. These warning flags would appear to largely invalidate what would otherwise be considered a highly valued condition being considered by the parties and which certainly CUB is advocating – namely, the condition that "customers of PGE shall be held harmless if PGE's revenue requirement is higher due to Oregon Electric's ownership of PGE."

Q. Mr. Piro discusses how the Company has, at times, experienced a common equity ratio below the 48% envisioned as a ring fencing condition. He concludes that the 48% common equity ratio minimum is conservative. Do you have any response to this observation and conclusion drawn by Mr. Piro?

A. I understand the condition of the limitation on dividends that would be invoked if the common equity ratio falls below 48% was reached by settlement among the parties at the time Enron acquired PGE in 1997. It is a condition expected to be continued if this transaction is approved. I am not suggesting that it be lifted or eliminated. That stated, I believe Mr. Piro's rebuttal testimony highlights another potential detriment of the transactions. Specifically, the parties and this Commission believed in 1997 that a minimum common equity ratio was necessary to help ensure the financial viability of stand alone PGE *because it going to be affiliated with a larger – and for the most part – unregulated entity.* This condition was imposed even though the Company had, in prior periods, been able to maintain an investment grade rating with lower common equity ratios.

As this Commission is no doubt aware, the cost of common equity is typically higher than the other sources of permanent capital available to the utility– particularly and significantly because the equity return is not tax deductible like the interest requirement associated with debt financing. The point being that, if PGE rates continue to be developed by considering the stand alone relatively-equity-rich capital structure of PGE, certainly at times capital costs may not be minimized. In other words, the condition of maintaining a 48% PGE-stand-alone-common equity ratio, if reflected for ratemaking purposes as the Applicants argue, will likely at times result in a higher return and income tax requirement than would result if PGE were actually a stand alone company *without the 48% minimum common equity ratio.*

In summary, the Company's preemptive strike against any party in the future ever claiming that the double leveraged capital structure has raised capital costs, as well as the acknowledgment that the 48% common equity ratio may not be necessary – or necessarily the most cost effective capital structure, argue for reflection of the Oregon Electric consolidated capital structure for ratemaking purposes and/or some rate crediting for retail ratepayers to help ensure that the proposed transaction provides a “net benefit” to ratepayers.

Q. Is there any other rebuttal testimony that you would like to address?

A. In my opening testimony I suggested that, at least for a period of time, savings envisioned from economies of scale stemming from Enron’s acquisition of PGE should be credited to ratepayers. To ensure the ability to quantify lost economies resulting from PGE’s extraction from Enron, I first recommended that PGE be required to identify and track *incremental* costs incurred on an ongoing basis to replace the corporate governance and overhead functions now undertaken by Enron. Additionally, I recommended that PGE be required to produce and retain amounts paid by PGE to Enron for corporate services formerly provided by Enron which would now be provided on a stand alone PGE basis.

Messrs. Tinker, Murray and Hager have responded that the Company is now preliminarily estimating that PGE’s stand-alone costs to replace services formerly provided by Enron will be slightly *less* than the direct and indirect charges allocated to PGE by Enron. They later conclude that “[o]n an overall basis, it is clear that separating from Enron does not create significant net “diseconomies” because our preliminary estimates suggest that PGE’s stand-alone costs will be slightly less that [SIC] the direct and indirect charges allocated to PGE by Enron.” PGE/200/Tinker-Murray-Hager/21.

Q. Should PGE ratepayers continue to be credited $9.0 million expected when Enron acquired PGE if, in fact, no economies from affiliation with Enron are lost following the separation?

A. No. If the economies never existed, it would not be equitable to impute "lost" economies following PGE's removal from the Enron empire. Having reviewed numerous utility merger/acquisition applications, I find it interesting that the Enron/PGE acquisition may not have generated any "economies of scale" or "synergy" savings. Over the last several years I and other members of my firm have skeptically reviewed many claimed "merger savings" that were offered by merging utilities in an attempt to effectively recover a premium over book value being paid. That stated, I do not believe my original conditions requiring PGE to track incremental costs incurred to undertake services previously provided by Enron, as well as the Enron costs charged to PGE for such services in recent years, are unreasonable. If PGE's "preliminary estimates" are correct, such record keeping will only verify that there are no "lost economies" from the Enron extraction. If "lost economies" are identified through such accounting requirements, at least the parties will be in a position to argue their respective positions as to how such "lost economies" should be considered in future PGE rate proceedings.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

September 15, 2004

TO: Jason Eisdorfer
Citizens' Utility Board of Oregon

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM-1121
PGE Response to CUB Data Request 113
Dated August 30, 2004
Question 094

Request:

Reference page 17 of the rebuttal testimony presented by Messrs. Tinker, Murray and Hagar. Provide all analyses and studies supporting the statement that "[o]ur best estimates today indicate that, rather than a 'diseconomy,' PGE's stand-alone costs to replace services provided by Enron will be slightly less than the direct and indirect charges allocated to PGE by Enron."

<u>Response</u>:

Attachment 94-A provides the requested documentation.

Submitted and Prepared
By: Patrick Hager
Bates Range Nos: 205106 – 205107
Attachment 094-A Bates Range 205108

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Attachment 094-A

Supporting Documents for Tinker, Murray and Hagar

Bates Range No. 205108

2005 Estimated Costs without Enron		
Financial services	0.4	(1)
Information Technology including ERP, internet services, software services, and industry information	5.4	(2)
Human Resources including benefits administration	1.9	(1)
Legal services	0.1	(2)
Financial analysis	0.3	(1)
Accounting and tax services	0.1	(2)
Executive services	1.6	(2)
Group Health	16.0	(3)
Insurance	4.3	(3)
401K	9.2	(3)
Total Replacement costs	39.3	

2002 Test Year Costs with Enron	
Direct Charges	31.5
Allocated	10.6
Total	42.1

Notes:

(1) 2003 estimate of services received through Enron allocations. Current expectation is that replacement costs will be somewhat lower.

(2) 2003 estimate of services received through Enron allocations. Current expectation is that replacement costs will be approximately equal.

(3) 2004 estimate of replacement costs for direct charges from Enron.

CERTIFICATE OF SERVICE

I hereby certify that on the 22th day of September, 2004, I served the foregoing Surrebuttal Testimony in UM 1121 upon each party listed below, by emailing a nonconfidential copy, and mailing through the U.S. mail, postage prepaid, two confidential exhibits to the appropriate parties as identified on the service list, and by hand delivering a copy to the Commission in its Salem offices.

Respectfully submitted,

Jason Eisdorfer #92292
Attorney for Citizens' Utility Board of Oregon