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PIRO

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PGE Financial Health

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony of

James J. Piro

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I. Introduction

Q. What is the purpose of your testimony?

A. I present testimony on several topics, all from my perspective as Portland General Electric's (PGE) Chief Financial Officer (CFO). In summary, I:

- Rebut the claims that Oregon Electric's debt service needs will place unusual pressure on PGE to cut costs. I provide perspective on the obligations that management has with respect to PGE's financial results regardless of who owns our common equity stock (Section II).
- Address the claims that PGE will be unable to access capital efficiently and economically after Oregon Electric acquires PGE's common equity stock. In this Section, I review PGE's historical capital structure. I describe the Enron merger conditions and discuss their role in protecting PGE's access to capital during Enron's bankruptcy. I also explain the process by which the rating agencies assign ratings to PGE's debt and the relationship between such ratings and PGE's cost of debt. The complexity in both the ratings process and how debt is priced make it very difficult to quantify the impact of one factor – such as PGE's ownership – on the market interest rate for given debt issuance (Section III).
- Discuss my experience with Oregon Electric's review of Port Westward and provide some perspective on the claims that the period over which an investor plans to hold a utility' stock dictates the horizon over which the utility will plan and make investments (Section IV); and

- Respond to Staff's request that the rebuttal testimony explain PGE's liabilities to a greater extent, including which liabilities might be the responsibility of customers. I also address briefly here certain proposals by the City of Portland and the Eugene Electric and Water Board (Section V).

Q. Please describe your role as CFO.

A. The CFO is accountable for leading and directing the company's efforts to maintain financial health and for the accounting integrity of the business. Typically, for a utility, the CFO will manage functions including corporate finance, accounting, tax, budgeting, governance, business insurance, internal audit (which also reports to the CEO), and risk management for power contracts and trading. My current organization chart is attached as Exhibit 101. By combining these functions under my supervision, I can monitor the financial health and controls of PGE, detect potential business or operating risks, advise the CEO on potential mitigating actions to take, and work with all the other officers to respond to business issues that affect PGE's finances as appropriate.

PGE must constantly balance near-term operating and expenditure choices with the potential short- and long-term consequences of those choices. In PGE's case, our obligations and opportunities as a public utility set the parameters for those consequences. PGE has an obligation to provide safe and reliable electric service to any person or business requesting it within our service territory and to do so at reasonable prices set by the Oregon Public Utility Commission (OPUC) from time to time. This means that, in the short-term, there are many costs that PGE cannot avoid because, if we did so, we could fail in our obligation to provide service. Moreover, Oregon's statutes, regulations, and regulatory framework allocate certain requirements or risks to PGE that affect the near-term consequences of any decision to change O&M or capital expenditure levels. For example, PGE bears the risk that decreases in the availability of our generating plants may cause us to incur higher power costs in a given year as we replace the lost output with market purchases. Finally, customer satisfaction significantly affects our short-term and long-term business outcomes and, thus, we always weigh the effects of various proposed capital expenditure and cost changes on customer satisfaction.

In the long-term, PGE's opportunities lie in our earning and retaining regulatory, customer, and public support of the proposition that we make the operating and investment decisions deemed necessary to meet our customers' electric infrastructure and service needs. Key drivers for PGE's long-term success at this include not only customer satisfaction, but also the trust that comes from decisions made day-in and day-out in a way that demonstrates consideration of all important interests. We must also ensure that the regulatory framework for such operating costs and investments provides our investors the opportunity to receive fair compensation for the capital they invest and put at risk in the business.

II. PGE Will Not Face Unusual Pressure To Cut Costs Under Oregon Electric's Ownership

Q. What testimony are you rebutting in this Section?

A. A representative sample of the testimony I address below is this quote from ICNU witnesses Antonuk and Vickroy: (ICNU/200,Antonuk-Vickroy/7, lines 12-17)

> "The transaction would produce a strong need for PGE to make utility cash flow available to support parent debt payments. That need would create a corresponding concern about assuring that future utility cash flows remain dedicated to debt payment. Moreover, in the event that financial circumstances worsen in the future, there will exist pressure to increase those cash flows, to the potential detriment of the utility."

Other witnesses, including Staff witnesses Morgan (Staff/200, Morgan/35, line 9) and Durrenberger (Staff/300, Durrenberger/3, lines 18-20; Durrenberger/9 lines 20-22), and CUB witness Dittmer (CUB/200, Dittmer/38, lines 13-18) make the same or a similar point.

Q. Do you agree that Oregon Electric's debt service obligations present a unique risk to PGE's customers because PGE may cut costs to produce sufficient income to pay dividends to Oregon Electric for debt service coverage?

A. No, I do not agree with this. Using PGE's last approved test year – 2002, developed in Docket UE 115 – the Commission set prices to enable PGE the opportunity to generate $97 million net income per year. The worst sensitivity studies in Applicants' financial model suggest that, even if PGE were to earn a net income of between $50 million and $65 million a year (a return on common equity of between 5.0% and 6.5%), <u>every year for five years</u>, Oregon Electric could meet its debt service requirements. These are the scenarios Staff requested in which PGE's earnings before interest and taxes (EBIT) drop by 30%. As CFO, I believe that the circumstances that would produce the results modeled in this sensitivity are highly improbable. Oregon Electric witness Wheeler provides more detail on earnings sensitivities and debt service in section IV –A of her rebuttal testimony. Based on a review of PGE's earnings over the last fourteen years, PGE's utility earnings dipped below this level in only one year and approached it in only one other. These instances were twelve years apart.

If the conditions producing these results appeared to be long-term, PGE management would certainly recommend – irrespective of our ownership – to our Board that PGE seek approval from the Commission to raise prices for the change in costs. PGE is a cost-of-service business. We expect that the Commission will allow us to set prices that provide us an opportunity to recover from customers our costs of serving them and Applicants likely do too. This is a fundamental precept of the regulatory compact.

If the cost increases producing these results were caused by some of the risks the regulatory framework currently allocates to PGE, such as customer load and power cost variability, it is unlikely such variations would persist year after year for five years. If such variations began to persist, again management would certainly recommend – irrespective of our ownership – to our Board that we seek changes in the regulatory risk allocation because PGE would no longer have the opportunity to earn a compensatory return on equity. It is doubtful that a utility, under any form of ownership, could allow wide negative variations to persist long without asking the regulators to revisit what is "normal." That is precisely what

PGE has done and is doing around our most significant, year-to-year variance: hydro production.

Q. But wouldn't Oregon Electric expect PGE to cut costs if load or power cost variations adversely affected financial results even in one year?

A. If PGE experienced <u>one</u> year with poor financial results, I expect that management would recommend to the PGE Board and Oregon Electric the same thing that we have recommended to our Board and Enron over the last several challenging years: that we minimize spending. Again, this is not unusual. One of management's jobs is to do this. Minimizing spending in response to adverse weather or power conditions in a given year is not the same as "cutting costs," at least as I understand how the parties use that term. The key expenditures needed to meet our commitments to customer service, safety, and reliability are not eligible for such cost minimization efforts.

When PGE minimizes spending in one year, we generally expect to restore such spending in the following year. Areas in which PGE has made reductions in the last several years include advertising, memberships, donations, market research and customer surveys, business expenses, consulting, office relocations, and equipment replacement programs for such assets as computers and vehicles.

I want to note here that I disagree with ICNU witnesses Antonuk-Vickroy, who states that PGE's key drivers for financial results are loads, O&M levels and growth rates, annual capital spending, and Port Westward. (ICNU/200, Anotnuk-Vickroy/28, lines 23-24 and 29 line 1). The variation in, and growth rates of, PGE's O&M levels have much less impact on our financial results than power cost variations. Overall non-power O&M for PGE is just $279 million for 2004. This compares to $272 million in the 2002 test year. This number simply doesn't move much year to year.

Q. Even if Oregon Electric's debt service requirements will not put unusual pressure on PGE to cut costs, won't meeting Oregon Electric's investment goals require cost cutting?

A. As Applicant witnesses Davis and Jackson explain, cutting costs in such a way that a utility reduces customer service and reliability not only does not add value, it significantly detracts from value. Strong customer service, including excellent reliability, helps create a healthy relationship between the utility, its customers, its regulator, and the community. In my opinion, this is one of the most important drivers for PGE's value to an investor.

I expect that our Board, representing the interests of our owners, will ask management to do precisely what CUB's witness Dittmer says that regulation asks utilities to do (CUB/200, Dittmer/20, lines 16-19): "[The] regulatory compact requires utility ownership and management to strive to cut costs by reviewing modern technology options and modern business practices (such as best-in-class surveys/studies) without jeopardizing safety or reliability." Regulation employs several means to ensure that regulatory policy strengthens, rather than weakens, a utility's incentive to find savings and efficiencies. Among the tools is the requirement that all of our expenditures – O&M or capital – be prudent, the Commission's ability to disallow expenditures, and the retroactive ratemaking prohibition that results in utilities retaining cost savings achieved between rate cases.

Q. As a CFO, do you believe the scenario various parties assert that Oregon Electric will cause PGE to cut costs, sacrificing service quality, so that Oregon Electric can pay down its debt and sell the stock in short order?

A. No, little about this scenario makes sense to me. As CFO, I expect any direction received from Oregon Electric, as well as from PGE's Board, to be aimed solely at maintaining or enhancing PGE's value. Adding value requires continually improving the quality of a company's assets and its customer service while operating the business in a cost-efficient and profitable manner. For example, re-designing processes can add value. This is hard work, not accomplished overnight and it requires careful planning. Typically, a process re-design can take several years to produce good results.

It is also unrealistic to think that Oregon Electric could cause PGE to engage in extreme cost cutting without Commission intervention. We file our capital budget annually. If the budget were to take a precipitous decline, the Commission would surely notice and undoubtedly ask questions about it. We do not file our entire O&M budget annually, but the Commission has authority to request it at any time and review with us any variances. We also file annually our actual results from the previous year, both unadjusted and adjusted to present a regulatory view of our expenditures and earnings. These reports compare the most recent year to the prior year and to the last approved test year and discuss reasons for differences in expenditure levels. PGE witnesses Hager, Tinker, and Murray provide PGE's most recent such report in PGE Exhibit 202.

In addition to this financial reporting, most of our important distribution reliability and safety programs receive annual program reviews from the Commission and we review our tree-trimming program with the Commission quarterly. We also meet quarterly with the Commission on customer complaints, reviewing activity and trends and discussing steps we are taking to address any issues of service quality. This all happens under the current comprehensive service quality program that Oregon Electric has committed to extend for ten years.

While the Commission cannot, generally speaking, force us to spend money, no utility wants to take actions (or not take actions) that will diminish the strength of its relationship with its regulators and customers or put its assets at risk. A supportive and fair regulatory environment is incredibly important to prospective investors, whether they invest with equity or debt.

Overall, I believe that our internal budget review process (including approval by the PGE Board of Directors), augmented by formal and informal filings and reviews with the Commission, creates a high level of transparency and ensures that our O&M and capital expenditures are at appropriate levels. The scenario Staff and other parties express concern over would be highly unlikely in this environment.

III. Oregon Electric's Ownership Will Not Impair PGE's Access To Capital

Q. What testimony are you rebutting in this section?

A. I am rebutting the claims of various Staff and intervenor witnesses that Oregon Electric's ownership, by itself, will impair PGE's access to capital on economical and efficient terms and result in weak capitalization (Staff/200, Morgan/29, lines 11-13; ICNU/200, Antonuk-Vickroy/5, lines 13-19; COP/100, Anderson/5; CUB/100, Jenks-Brown/13, lines 14-16; CUB/200, Dittmer/26, lines 9-13).

I start with some historical background on PGE's capital structure and why I believe PGE's capital structure will remain strong after the transaction. Then I describe the Enron merger conditions and their role in protecting PGE's access to capital during Enron's bankruptcy. I next explain the process by which the credit rating agencies assign ratings to PGE's debt and the relationship between such ratings and PGE's cost of debt. The complexity in both the ratings process and how debt is priced make it very difficult to quantify the impact of one factor – such as PGE's ownership – on a market interest rate on a given debt issuance.

Q. What capital structure has PGE had historically?

A. PGE's capital structure has varied over the last 20 years, as Exhibit 102 shows. This 20-year period is a useful reference because of both the variety of corporate structures and the range of capital investment needs. In terms of corporate structure, from 1984 until 1986, PGE was a stand-alone utility company and our stock was publicly traded on the NYSE. In 1986, Portland General Corporation (PGC) was formed to hold all of PGE's stock and became the stock traded at the

NYSE. In 1997, PGC merged with Enron. In terms of investment needs, this 20-year period includes the completion of Colstrip 3 and 4, the 1994-5 construction of Coyote Springs, and the period of Trojan's steam tube-related difficulties and ultimate shut-down, as well as significant distribution system investment.

For the fourteen years beginning in 1990, Exhibit 102 shows the capital structure using the same methodology used by the Commission in applying the 48% limitation on equity below which Enron cannot make distributions. For the twenty years look beginning 1984, the chart uses data from our publicly filed financial statements.

Q. What do you conclude from this history of PGE's capital structure?

A. The most obvious conclusion is that the 48% common equity ratio below which Enron, and Oregon Electric, if approved, cannot take distributions is conservative by PGE's historical standards, as there were a number of years in which PGE operated with its equity below 48%. PGE spent the last half of the 1980s and early 1990s at or around 45% equity, and made many sizable capital investments during this period. Because of Enron's decision not to receive dividends from PGE while working through Enron's bankruptcy process, we are currently at historically high levels of equity. I cannot agree with Staff (Staff/200, Morgan/29, lines 11-13) that PGE has "weak capitalization," whether we remain at the 2003 reported level of 55.6% common equity or move to the anticipated post-closing level of around 48%.

A key point to note here is that, irrespective of Oregon Electric's transaction, the PGE Board is likely to declare a dividend, as Enron witness

Bingham explains. This dividend will reduce the PGE equity account from today's historically high levels down to a level at or slightly above the 48% threshold. In fact, the up-front dividend that Oregon Electric has modeled as a component of the proceeds to Enron is entirely consistent with the one we have modeled in PGE's financial forecast. The planned equity levels, no matter who owns PGE, are roughly the same.

Q. Is a capital structure with at least 48% common equity for PGE the "right" capital structure?

A. That depends on one's objective. Certainly the percentage of equity in the capital structure is one element that plays a role in PGE's debt ratings, as I discuss below. Debt ratings are also based on a full package of other criteria including power supply, operations, regulatory environment and management. Looking at PGE's bond ratings and capital structure, PGE achieved its highest ratings in the last 20 years from Moody's of "A2" during 1985–1989 and 1996–2000 with average common equity ratios of 44.9% and 53.5%, respectively. PGE received its highest S&P rating over the last 20 years of "A" during 1985-1990 and 1996-2000, with average common equity ratios of 44.4% and 53.5% respectively. This data suggests that bond ratings are based on many factors of which the common equity level is just one.

I do not view the 48% contained in the Enron merger conditions as a Commission decision that 48% (or higher) is the "right" amount of common equity for PGE. This number was a settlement figure, adopted by the Commission. Indeed, in Order 01-777, the Commission found that a common equity ratio of 45% was the average for a comparable group of electric companies and, consequently, the Commission reduced PGE's cost of equity by 0.25% to reflect the reduced risk of our higher common equity ratio. Following this decision, it might have been appropriate for Enron and PGE to seek a change in the 48% limitation set by Order 97-196. The wholesale market liquidity crisis and Enron's bankruptcy overtook us, however, and we did not pursue this.

Q. Will PGE's capital structure be sufficient under Oregon Electric's ownership to enable PGE to provide safe and adequate service?

A. Yes. Oregon Electric's ownership, by itself, will not weaken PGE's capital structure. PGE's capital structure after the transaction closes will be relatively the same regardless who owns PGE's common stock and will not be "weak," as Staff claims. Dividends taken by Oregon Electric will always be within the limitations of the 48% ring-fencing construct, which is consistent with the approach we have used in our own financial modeling.

Q. Has PGE retained access to capital through the Enron bankruptcy?

A. Yes. Notwithstanding the size and complexity of Enron's bankruptcy, PGE operated normally during this period, continued to maintain and invest in the system, and retained investment-grade credit ratings from Moody's and S&P. In late 2001 through most of 2002, we spent considerable time answering questions about Enron's bankruptcy posed by both the rating agencies and potential lenders. We worked to create additional comfort for the rating agencies by obtaining a non-consolidation opinion. The Commission helped us enhance the Enron merger conditions with the golden share, which requires an affirmative vote (with certain exceptions) from the holder of the share for a voluntary bankruptcy petition to be filed with respect to PGE.

It is important to recall that 2001 and 2002 were difficult not just for PGE but for the entire industry for many reasons including the western power market crisis. Yet, we accessed capital throughout this period, raising $150 million of funds through a sale of bonds to a commercial bank in December 2001, $72 million of a revolver in June 2002, and $250 million of 10-year bonds issued primarily to insurance companies in October 2002. It was hard work and not all lenders' doors were open. Nonetheless, we maintained liquidity adequate to fund capital and operating needs throughout this period.

Q. You referenced investment grade ratings above. What are investment grade ratings and why are they important?

A. Investment grade ratings are ratings that are BBB- or better from S&P or Baa3 or better from Moody's. In general, the difference between investment grade ratings and non-investment grade ratings is a difference in the interest rate the rated entity would expect to pay on new debt. In addition, investment grade unsecured bond ratings affect a utility's ability to purchase energy from power and fuel market participants and the credit provisions such participants require.

Although some potential investors have limitations precluding them from investing in companies that do not have investment grade ratings, this is not a significant driver of the effect of having such ratings. The driver of the effect of investment grade ratings on cost of debt is perceived risk and, as I explain below, credit ratings are just one input considered by lenders in pricing debt.

Q. How do the ratings agencies determine their ratings?

A. S&P publishes a description and list of the criteria it reviews. The categories of issues it examines are in two broad groupings: business risk and financial risk. Within business risk, important points include industry characteristics, marketing, technology, regulation, efficiency and management. As I noted above, the list of considerations includes the utility's cost structure and operating efficiency. Within financial risk are financial characteristics and policy, profitability, capital structure, cash flow protection, and financial flexibility. The analytical groups within the agency score various companies on each of these categories. Exhibit 103 is an excerpt from the publication that describes this. Although S&P's description implies a fair degree of precision, its explanation of the process is enlightening:

> "There are no formulae for combining scores to arrive at a rating conclusion. Bear in mind that ratings represent an art as much as a science. A rating is, in the end, an opinion. Indeed, it is critical to understand that the rating process is not limited to the examination of various financial measures. Proper assessment of debt protection levels requires a broader framework, involving a thorough review of business fundamentals, including judgements about the company's competitive position and evaluation of management and its strategies. <u>Clearly, such judgments are highly subjective; indeed, subjectivity is at the heart of every rating.</u>" Emphasis added.

Moody's also analyzes companies from both a quantitative and qualitative approach and considers each issuer on its unique individual merits considering a host of quantitative and judgmental factors. Moody's believes that relative stability and predictability of future cash flows is driven principally by a host of qualitative factors broadly falling into the following categories: industry characteristics, quality of management and the strategic plan and fundamental competitive position.

Q. Staff witness Morgan testifies that private ownership of PGE may adversely affect PGE's credit ratings (Staff/200, Morgan/53, lines 5-7) because of the lack of regulatory oversight of the owners. Do you agree?

A. No, nothing in S&P's description of its process or my knowledge of the process suggests this is the case. A company typically provides the rating agencies all of the information, confidential or otherwise, they need to determine a rating. I cannot think of any information about Oregon Electric or PGE that any of the agencies might require that would not be provided. In addition, PGE will continue to file 10K's, 10Q's, and 8K's with the rating agencies. Concern over the lack of regulatory oversight of Oregon Electric will also be mitigated through conditions implemented as a result of the acquisition. This risk is not real.

Q. Is there a regular time at which Moody's and S&P update ratings?

A. No. Moody's and S&P implement rating changes only when a meaningful change in credit quality of a company has occurred. Rating changes are typically preceded by a change in the companies credit outlook; either "creditwatch negative/positive" or "on review for possible downgrade or positive", by S&P and Moody's, respectively. When either agency makes a change, and they do not necessarily occur simultaneously, the agency will issue a publication (release) explaining the primary drivers behind the re-evaluation of the change in rating. With respect to contact with the rating agencies, PGE's typically meets formally once during the year to provide a full annual review. However, we communicate regularly with the agencies, typically to provide company updates and answer questions.

Q. Based on your experience in dealing with the rating agencies on behalf of PGE, what can you conclude from a release announcing a ratings change?

A. The rating agency release sets forth the change in the ratings and the high level rationale behind the change. Since many factors are considered when assigning bond ratings, one cannot conclude that changing any one factor discussed in a ratings release would automatically result in a change in rating. 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.

Q. Please describe an example of what you mean.

A. I'll use as an example the S&P release on December 7, 2001. This release announced S&P's decision to lower PGE's corporate credit rating from A to BBB+. The release discussed the Enron bankruptcy and the pending sale of PGE's common stock to Northwest Natural Gas (NNG), with high debt balances in the holding company over PGE and NNG. Considerations included that the combined PGE and NNG utility would have "moderately low-risk," with supportive regulation, above-average service territory growth, a favorable competitive position, and solid operations. Tempering factors were single-state focus, energy-price volatility in the western U.S., and a slowdown in the regional economy.

Shortly thereafter in May 2002, one of the major assumptions cited in the S&P release, PGE's sale to NNG, was no longer in place due to the cancellation of the purchase agreement. In September 2002, PGE issued one share of Limited Voting Junior Preferred Stock (what I mentioned above as the "golden share"). The issuance of this "golden share" enhanced the ring-fencing conditions and helped further insulate the credit quality of PGE from its parent Enron. Also, it became abundantly clear as time went on that PGE was not going into bankruptcy. Other events also happened during this period of time. At the end of 2002, PGE's power cost adjustment clause expired, changing one of the key regulatory parameters S&P examines. At the end of 2002, the Commission disallowed over $25 million in power costs PGE had already incurred to serve customers in 2003. Further, in 2003, the Northwest had another poor water year and, in early 2004, the Commission denied PGE any recovery for the related additional power costs. In late 2003, PGE settled the major FERC investigation concerning it, along with several of the California claims.

I cannot say with certainty how any of these events or circumstances impacted the rating agencies' view of PGE's credit quality. All I know is that the aggregation of all of these events and circumstances did not cause S&P to change PGE's ratings during this time.

Q. How do a utility's credit ratings affect the cost of a particular issuance?

A. A bond's interest rate is based on the sum of the corresponding treasury yield and the credit spread investors require to have the incentive to purchase the bonds. If PGE is issuing a 10-year bond, then typically a 10-year treasury yield is used. PGE's credit spreads change over time and reflect both the accumulation of all public information in the market encompassing PGE's credit worthiness and an assessment of PGE's ability to generate cash sufficient to repay interest and principal on its debt obligations. Additionally, PGE credit spreads will reflect an assessment by investors in the overall risk in the energy/utility industry sector. If there is uncertainty in a specific industrial sector, a bond investor may either avoid that sector entirely or require additional compensation (coupon) for taking on the industry risk. Investors will refer to the S&P and Moody's bond ratings as one piece of information but, in making their investment decision, will also conduct their own due diligence on PGE's credit worthiness. Investors also look at the underlying collateral associated of the bond. Is the bond secured by PGE's first mortgage or is it unsecured debt of PGE? One other item that affects bond credit spreads is the overall environment in the capital markets: general market forces over time can and do, increase or decrease credit spreads.

Q. Do you believe PGE will remain investment grade under Oregon Electric's ownership?

A. Yes, I believe both S&P will maintain investment grade ratings for PGE under Oregon Electric's ownership, all other things being equal. We expect, based on the S&P release, an S&P senior secured rating of BBB+, corporate credit rating of BBB, and senior unsecured rating of BBB-. All of these ratings are investment grade. Key reasons S&P gives for maintaining investment grade ratings include PGE's strong financial profile, likely OPUC conditions on the transaction, elimination of management uncertainty and potential Enron liabilities, and Oregon Electric's commitment to use dividends to pay interest, reduce debt and cover the minimal Oregon Electric operating costs and other obligations.

Q. Does this mean that it is certain PGE will retain investment grade ratings into the future?

A. No, but the crisis would have to be with PGE for Oregon Electric to face financial difficulties. Because Oregon Electric's strategic plan is to focus PGE on its regulated business and not highly diversified unregulated businesses, a sustained financial crisis at PGE under Oregon Electric's ownership is very unlikely. The primary reason for such a crisis would be an uncorrected misalignment between our costs of service and regulatory coverage of those costs. The only cost area large enough for such misalignment to be a serious financial issue is power costs. It is precisely to prevent such misalignment, among other reasons, that commissions adopted least cost planning processes. PGE works hard to ensure that both our short- and long-term resource decisions are in line with customer and regulatory expectations and qualify for cost recovery. A misalignment should not occur over a sustained period if the regulatory compact is working. Another possible cause would be adverse litigation outcomes not recoverable from customers.

Q. Do you agree with the parties' assertion that Oregon Electric's capital structure will increase PGE's cost of debt?

A. I agree that this is theoretically possible and acknowledge the S&P release of March 10, 2004, which placed PGE on creditwatch with negative implications and highlighted the amount of debt in the consolidated capital structure. I also agree that one can discover from the marketplace, at a given moment in time, an average spread between a credit rating of, say, BBB+ and BBB. As I explained above, however, a credit rating is not based solely on one factor, such as capital structure, and reasons cited in a given release may or may not continue to be key factors as time passes and other events occur. I also explained that the relationship between a firm's credit rating and the cost it pays for a particular debt issuance is even more tentative.

Even if I assume away these practical difficulties on measuring and attributing the effect of a credit rating change for PGE, the effect of the change S&P has indicated as likely is small on the financing activity PGE expects over the next five years. Let me note again that the following assumes that no other events affect PGE's ratings over these five years. The majority of PGE's debt is long-term, fixed interest rate instruments[1], which means that these interest obligations will not change regardless of our credit ratings. Through 2009, we currently expect our long term financing needs to be met primarily with senior secured long term bond offerings. S&P's rating guidance, as previously discussed, has PGE's senior secured bond rating being maintained at the BBB+ level. Thus PGE's borrowing costs on the senior secured issuances should be minimally impacted, if at all.

[1] The exception is PGE's short-term debt. This debt, however, does not affect PGE's revenue requirement. Revenue requirement instead uses the working capital concept.

With the elimination of PGE's ownership uncertainty, the company's Outlook by S&P could improve from "creditwatch negative" to "stable" or "developing." If this outlook change occurs PGE could experience a modest improvement in interest rates on new bond offering. This is, of course, all else being equal.

In conclusion, as someone with experience raising capital in the marketplace, I disagree with such assertions as that by CUB witness Dittmer that PGE will be able to access capital only "at rates that would be considered expensive or unreasonable when compared to safer debt securities." (CUB/200, Dittmer/26, lines 9-11).

IV. Port Westward and Oregon Electric's Incentive to Invest

Q. What testimony are you rebutting in this section?

A. Several parties have questioned Oregon Electric's commitment to the Port Westward plant. I explain below why neither PGE nor Oregon Electric have stated definitively that PGE will proceed with Port Westward. I also address the concern that the period over which Oregon Electric plans to hold PGE's stock limits the duration of PGE investments they would support.

Q. What is the status of PGE's development of Port Westward?

A. PGE has not yet completed negotiations for engineering, procurement and construction (EPC) and the manufacturing and warranty of the critical power island components. The contracts are the last steps necessary before we can obtain final corporate approval to proceed. The other necessary steps were the Commission's July 20, 2004 acknowledgement of our Integrated Resource Plan Action Plan and agreement to waive the rule requiring that all new resources be reflected in rates at "market," rather than the traditional rule of cost. Completing contract negotiations will provide us necessary assurance that the cost of this project will, in fact, make it the least cost option for PGE to pursue fulfilling this piece of the Action Plan. This information is also necessary for Applicants to take a position on the development of the plant as specified under the Purchase and Sale Agreement.

Q. When do you expect that PGE will be ready to make a final commitment to proceed with Port Westward?

A. We presently expect to finish all necessary processes in August or September.

Q. Do you disagree with claims such as that of CUB witnesses Jenks and Brown that: "for short-term investors, when push comes to shove, short-term profits will take precedence over long-term development?" (CUB/100, Jenks-Brown/8, lines 12-13)

A. Yes, I do. Just as I disagree with Staff's assertion that: "the nature of the investment fund would not likely create a very long-range planning horizon for PGE." (Staff/200, Morgan/49, lines 9-11). Enron, at least since 1999 when PGE was first put up for sale, has not been a "long-term investor." Yet, PGE has continued to invest in our distribution system and generating plants, performed several major plant upgrades and run an acclaimed hydro re-licensing program.

As I indicated earlier, it is highly unlikely that an investor in a utility would take any action with respect to utility investment unless it is to maintain or increase the value of that investment, in connection with providing safe and adequate service at reasonable costs. For a utility, ongoing maintenance and capital asset replacement are among the most important things one must attend to in order to maintain or increase the utility's value. Indeed, several witnesses note that long-term investments such as Port Westward might be expected to actually improve Oregon Electric's return on its investment.

Thus, I take issue with the parties' position that Applicants' plan to sell PGE's stock at some time in the future poses a risk to customers. (e.g, CUB/100, Jenks-Brown/8, line 18-20; CUB/100, Jenks-Brown/9, lines 1-6; CUB/100, Jenks-Brown/7, lines 7-11; CUB/100, Jenks-Brown/13, lines 1-3; ICNU/200, Antonuk-Vickroy/36, lines 19-20).

Q. What is your impression of Oregon Electric's commitment to Port Westward and to investing in the business?

A. I spent a considerable time with various representatives from and advisors to Oregon Electric over the last several months discussing Port Westward and earlier during their due diligence process.

Oregon Electric spent significant resources reviewing the pluses and minuses of the Port Westward project and ultimately concluded that they would support PGE management's recommendations to proceed with this investment, subject to a final cost evaluation based on the contracts I mentioned above. In their review of Port Westward, Oregon Electric analyzed and questioned our conclusions in a constructive and thoughtful manner, which helped both them and us to gain conviction that this project is a sound long-term investment for PGE and our customers. To the extent Oregon Electric did not have "in house" professionals who were knowledgeable in a specific area, they retained skilled advisors to help them in the evaluation. By supporting this substantial new capital project, it is clear to me that Oregon Electric is committed to investing in PGE's resource base.

During due diligence, Applicants did a thorough review of PGE's resources and expected future capital expenditures. Some combination of TPG professionals and appropriate advisors visited several of PGE's generation facilities. Further, my team and I took TPG through our forecasted capital budgets in detail to help them understand the expectations for the capital requirements to run this utility and maintain its capital base. I think that through this due diligence and work since the SPA was signed, Oregon Electric developed a solid understanding of the capital requirements necessary to support PGE's assets and its customers for the future.

V. PGE Liabilities and Other Topics

Q. What testimony are you addressing in this section?

A. I respond in part to Staff's concern that: "At this time, it is not perfectly clear which liabilities will ultimately remain with PGE and which may potentially affect PGE customers." (Staff/200, Morgan/8, lines 12-13). Oregon Electric witness Davis explains the indemnification provisions of the Purchase and Sale Agreement with respect to certain liabilities. I discuss below the general principle by which PGE decides whether to seek customer contribution to a liability and the liabilities that we are currently aware of to which this principle applies.

I also briefly address the City of Portland's position regarding a condition around PGE's franchise agreement with the City and the position of the Eugene Water and Electric Board (EWEB) that financial assurance be provided regarding PGE's obligations to decommission Trojan.

Q. What is the general principle PGE applies in determining whether it is appropriate to seek customer contribution to a liability or claim?

A. In general, if the liability or claim arises out of providing service to customers, relates to an asset that PGE has always devoted to regulated retail service or to a benefit that customers have already or will in the future receive, then we will seek coverage on the principle of matching costs and benefits.

Q. To which of the liabilities currently disclosed in PGE's SEC filings would this principle apply?

A. The principle of matching costs and benefits would apply to:

- The Colville Tribe claim against Douglas PUD relating to the Wells hydro-electric project on the Columbia River. PGE receives a share, devoted solely to retail service, of the output of this project under a long-term contract. It is our understanding that Douglas PUD proposes to resolve this claim through future payments and the dedication of a portion of the project's output to the Tribe. Since these forms of compensation would affect the future cost and output of the project, PGE would likely simply include the payment (as part of our share of project costs) and output effects in a future RVM. This is appropriate because customers receive all of the benefits of this contract.
- FERC docket EL00-95, the "California Refund." PGE has not yet received from California a significant amount of revenue from sales made there during 2000 and 2001. For a portion of those years, FERC may require a refund of the amount of any price found not just and reasonable. This refund would reduce the amount owed PGE. PGE's customers received the benefit of wholesale sales PGE made in the markets covered by the owed revenues and refund obligation during the period January 2001 through June 2001 (the end of the refund period). This period coincide with the power cost adjustment the Commission adopted in Order No. 01-231. When we determined the amount of the variance to amortize in 2002, we included $4.2[2] million as a reserve for uncollectible revenues (the combination of amounts owed and refunds due). Under the refund methodology recently propounded by FERC, this

[2] The $4.2 million was subject to the sharing provision of 90% to customers. Thus, the balance collected from customers resulting from this variance is $3.8 million (90% of $4.2 million)

reserve could almost double. PGE disagrees with FERC's methodology, because we believe that any methodology must recognize PGE's cost in making such sales and that our highest cost retail resources are the relevant cost support. It is possible that, if PGE's approach prevails, some of the reserve we previously took would not be necessary. When this case finally resolves itself, we plan to adjust the balance of the 2001 amortization to charge customers no more and no less than the mechanism requires for that period.

Q. Are these the only liabilities for which PGE would seek contribution from customers?

A. There may be others for which we presently lack enough information to determine whether the liabilities or claims meet the matching of cost and benefits principle I described above. In particular, two claims related to Colstrip and one related to PGE's Harborton plant, which we disclosed in PGE's 2004 Annual Report Form 10K and 2001 Annual Report Form 10K respectively, may meet PGE's principle. In the early stages of a claim, it can be difficult to identify the circumstances underlying it. The Commission should rest assured, however, that PGE vigorously defends each and every claim that PGE believes is unfounded. PGE will not seek customer contribution unless the claim reaches fruition and meets our principles.

Q. The City of Portland has suggested that Applicants commit, as part of this OPUC approval process, to make all reasonable efforts to develop and obtain approval of a modern franchise with the City of Portland within two years following the completion of the transaction. Do you have any comments on this suggestion?

A. Yes. PGE and the City have already begun the process of discussing a new franchise, under the joint sponsorship of Council member Randy Leonard and Peggy Fowler, PGE's CEO. We and the City have already met twice and are meeting regularly on this project. We have set forth goals and potential subject areas. The City is providing us one of the standard version contracts and we have provided them one of our most recent franchise agreements. Both sides have acknowledged that the franchise agreement should not be too specific, but should leave room for the many operational issues that inevitably come up and that smaller groups should address in the future after the main agreement is signed.

PGE is applying its resources to this matter because it is good business to do so. The City is a major electric service customer and a large municipal government within our service territory. We do not believe, however, that the Commission should condition its approval of Oregon Electric's application on PGE continuing to do this work. The Commission need not and should not insert itself in the middle of these normal utility business affairs.

Q. EWEB does not oppose the transaction but expresses some concerns through the testimony of Mr. Beeson, EWEB/100. What is PGE's relationship to EWEB?

A. EWEB is the electricity supplier for about 83,300 customers in Eugene, Oregon. We purchase some power from EWEB and transmit some power for them over PGE transmission facilities. EWEB is also a co-owner and co-licensee of the Trojan Nuclear Plant owing a 30% share of the plant. PGE and EWEB are parties to the 1970 Ownership Agreement for the Trojan Nuclear Plant, which EWEB has presented as EWEB/102.

Q. What are EWEB's concerns?

A. Mr. Beeson expresses concern about PGE's financial health resulting from the transaction. To the extent EWEB has general concerns about PGE's financial health as a result of the transaction, the concerns seem identical to the general concerns raised by other parties. Those concerns are addressed in my testimony and the other rebuttal testimony filed by PGE and the Applicants.

Q. Does EWEB have additional concerns?

A. Yes, EWEB seems to have an additional concern about PGE's ability to perform in the event unplanned decommissioning costs arise under the Ownership Agreement. Mr. Beeson is apparently concerned that if PGE does not pay all costs of operation, some of those costs may become EWEB's obligation under the Ownership Agreement. But EWEB's remedy in the unlikely event of such unplanned decommissioning costs is as a co-owner and a party to the Ownership Agreement and under Oregon contract law. It does not make sense for the Commission in this proceeding to give EWEB greater rights then it now has under the Ownership Agreement in the guise of imposing special financial conditions on this transaction that are only for the benefit of EWEB.

VI. Qualifications

Q. Mr. Piro, please describe your educational background and experience.

A. I received a Bachelor of Science degree from Oregon State University in Civil Engineering in 1974 with an emphasis in Structural Engineering. In addition, I have taken graduate courses in engineering, accounting, economics, and rate making. I am a registered Professional Engineer in Civil Engineering in the State of California (Registration No. 28174). I joined Portland General Electric in 1980 and have held various positions in Generation Engineering, Economic Regulation, Financial Analysis and Forecasting, Power Contracts, Economic Analysis, and Planning Support, Analysis and Forecasting.

Q. Does this conclude your testimony?

A. Yes, it does.

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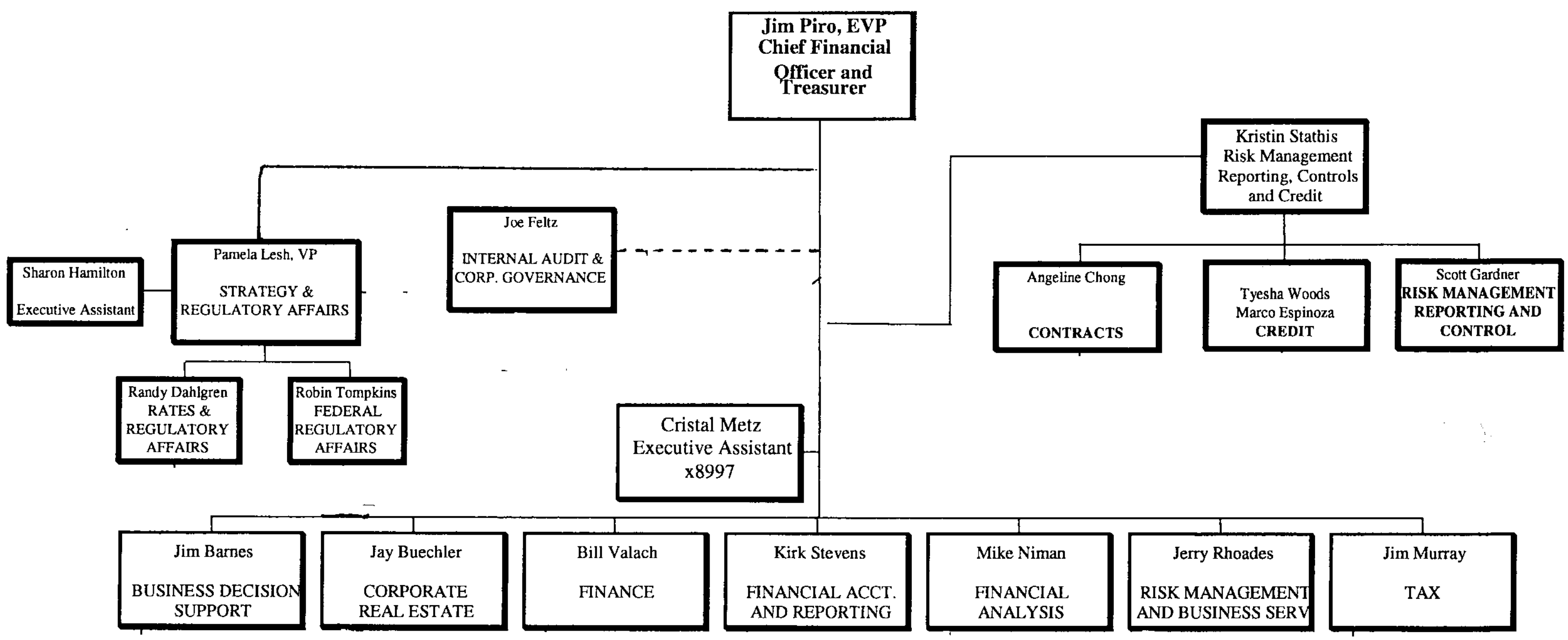
List of Exhibits

PGE Exhibit	Description
101	Piro's Organization Chart
102	PGE's Annual Historical Capital Structure
103	S&P Description of Ratings Criteria

FINANCE, ACCOUNTING & SUPPORT SERVICES CFO Organization



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PORTLAND GENERAL ELECTRIC'S ANNUAL HISTORICAL CAPITAL STRUCTURE

Actual 13-mo Average - Regulatory View (Semi-annual), %

	Portland General Electric		Portland General Corporation and Subsidiaries						Portland General Electric							
			1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Long-Term Debt			49.3%	48.2%	48.8%	46.0%	46.0%	48.2%	49.0%	48.6%	44.9%	40.6%	41.4%	38.9%	37.4%	43.3%
Preferred Stock			9.0%	8.7%	8.6%	8.8%	7.6%	6.1%	1.9%	1.6%	1.7%	1.7%	1.6%	1.5%	1.5%	1.1%
Common Equity			41.7%	43.1%	42.6%	45.2%	46.4%	45.7%	49.1%	49.9%	53.4%	57.8%	57.1%	59.6%	61.2%	55.6%
Total			100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: PGE, PUC Semi-annual Regulatory Reporting Results of Operations, years 1990-2003

End of Year Actuals from Consolidated Financial Statements (10ks), %

	Portland General Electric		Portland General Corporation and Subsidiaries										Portland General Electric							
	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Long-Term Debt	46.0%	42.7%	46.3%	47.7%	45.1%	47.1%	45.3%	52.4%	49.7%	48.4%	46.1%	48.8%	49.4%	51.7%	42.0%	39.6%	41.4%	40.7%	41.7%	43.9%
Preferred Stock	12.7%	12.2%	11.7%	5.8%	8.3%	8.9%	9.0%	8.6%	8.8%	8.0%	6.6%	2.2%	1.6%	1.5%	1.7%	1.7%	1.6%	1.5%	1.4%	0.0%
Common Equity	41.3%	45.1%	42.1%	46.5%	46.7%	44.0%	45.7%	39.0%	41.5%	43.6%	47.3%	49.0%	49.0%	46.7%	56.3%	58.7%	57.0%	57.7%	56.9%	56.1%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: PGE, SEC Form 10k

ELECTRIC UTILITY CREDIT WORTHINESS
SUMMARY CRITERIA

UM-1121/PGE EXHIBIT/ 103
PIRO / 1

Financial Resources:
- Stability and predictability of cash flow
- Financial ratios
    - Capital structure
    - Coverage ratios
- Access to capital markets for long term debt and equity issuance
- Short term liquidity availability
    - Access to commercial bank credit (revolvers)
    - Access to commercial paper market
    - Other alternative sources of capital

Power Supply:
- Diversified supply portfolio
- Cost recovery or hedging methods
- Financial and liquidity exposure to power supply costs
- Risk management
- Generating capacity versus demand
- Nature of supply contracts
- Environmental issues
- Transmission adequacy

Operations:
- Quality of service
- Cost structure and operating efficiency
- Labor relations

Customer Base:
- Customer mix and diversity
- Demand characteristics and service territory growth prospects/economy
- Access to competing energy sources
- Competitiveness of rate structure
- Customer relations

Regulatory Framework:
- Price setting and cost recovery mechanisms
- Predictability of the regulatory system
- Rate case success (ROE/disallowance's)
- Rules/stipulations (regulatory ring-fencing)

***Management*:**
- Experience and depth of management team
- Diversification and non-regulated activities
- Planning and strategic goals

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Industrials and Utilities

Standard & Poor's uses a format that divides the analytical task into several categories, providing a framework that ensures all salient issues are considered *(see box)*. For corporates, the first several categories are oriented to fundamental business analysis; the remainder relate to financial analysis. As further analytical discipline, each category is scored in the course of the ratings process, and there are also scores for the overall business risk profile and the overall financial risk profile. (Analytical groups choose various ways to express these scores: Some use letter symbols, while others prefer to use numerical scoring systems. For example, utilities scoring is from 1 to 10—with 1 representing the best. Companies with a strong business profile—typically, transmission/distribution utilities—are scored 1 through 4; those facing greater competitive threats—such as power generators—would wind up with an overall business profile score of 7 to 10.)

There are no formulae for combining scores to arrive at a rating conclusion. Bear in mind that ratings represent an art as much as a science. A rating is, in the end, an opinion. Indeed, it is critical to understand that the rating process is not limited to the examination of various financial measures. Proper assessment of debt protection levels requires a broader framework, involving a thorough review of business fundamentals, including judgments about the company's competitive position and evaluation of management and its strategies. Clearly, such judgments are highly subjective; indeed, subjectivity is at the heart of every rating.

At times, a rating decision may be influenced strongly by financial measures. At other times, business risk factors may dominate. If a firm is strong in one respect and weak in another, the rating will balance the different factors. Viewed differently, the degree of a firm's business risk sets the expectations for the financial risk it can afford at any rating level. The analysis of industry characteristics and how a firm is positioned to succeed in that environment establish the financial benchmarks used in the quantitative part of the analysis *(See Ratio Guidelines on pages 56-58)*.

CORPORATE CREDIT ANALYSIS FACTORS

Business Risk
- Industry Characteristics
- Competitive Position
  - (e.g.) Marketing
  - (e.g.) Technology
  - (e.g.) Efficiency
  - (e.g.) Regulation
- Management

Financial Risk
- Financial Characteristics
- Financial Policy
- Profitability
- Capital Structure
- Cash Flow Protection
- Financial Flexibility

Industry risk

Each rating analysis begins with an assessment of the company's environment. To determine the degree of operating risk facing a participant in a given business, Standard & Poor's analyzes the dynamics of that business. This analysis focuses on the strength of industry prospects, as well as the competitive factors affecting that industry.

The many factors assessed include industry prospects for growth, stability, or decline, and the pattern of business cycles *(see Cyclicality, page 41)*. It is critical to determine vulnerability to technological change, labor unrest, or regulatory interference. Industries that have long lead times or that require a fixed plant of a specialized nature face heightened risk. The

UM-1121 / PGE EXHIBIT / 200
TINKER-MURRAY-HAGER

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Capital Structure, Taxes And Enron Services

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony of

Jay Tinker
Jim Murray
Patrick Hager

August 16, 2004

I. Introduction

Q. Please state your names and positions at PGE.

A. My name is Jay Tinker. I am a project manager in the Rates & Regulatory Affairs Department.

My name is Jim Murray. I am Portland General Electric Company's Tax Director.

My name is Patrick G. Hager and my position is Manager, Regulatory Affairs.

Our qualifications are provided in Section VI of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony responds to several topics raised by Staff and other parties. Specifically, we address:

- Various aspects of Thomas Morgan's description of the cost of capital for regulated utilities, including the effect of capital structure on the cost of equity (Section II);
- The issues surrounding the Commission's policy of requiring utilities to calculate income taxes for revenue requirements purposes on a stand-alone basis (Section III);
- The assertion that PGE's removal from the remaining Enron corporate family will result in "diseconomies of scale" for which Applicants should compensate customers (Section IV); and
- Arguments raised against Applicants' proposal of an earnings sharing mechanism, by which customers would receive a portion of the upside associated with "between-rate-case" variability PGE faces (Section V).

II. Capital Structure

Q. What parts of Thomas Morgan's testimony regarding the cost of capital for regulated utilities do you address here?

A. Mr. Morgan provides the Commission some general principles and definitions related to the cost of capital as foundation for his discussion of the returns Oregon Electric may receive from its ownership of PGE's common equity stock and his explanation of the concept of "double leverage." While we agree with much of what Mr. Morgan has presented, his description of financial theory did not fully explain a concept critical to his discussion and, ultimately, to his conclusions. We describe that omission below and state its implication for Mr. Morgan's conclusions. He also did not fully apply his explanation of financial theory to the situation here. We offer a deeper application of his principles to Oregon Electric's situation. In short, the conclusion that Oregon Electric's cost of capital will be less than PGE's is not supported by financial theory.

Q. With what parts of Mr. Morgan's description of general financial theory do you agree?

A. We agree with the following:

- Capital structure refers to the relationship among the component sources of debt and equity financing used by a company. (Staff/200, Morgan/23, lines10-11)
- A firm's cost of equity is the rate of return on equity that investors require on their equity investment, given the risk of the investment. An investor's expected return is defined as the return on equity that an investor would expect to receive on other investments of similar risk. (Staff/200, Morgan/23, line 20 and Morgan 24, line 2)
- The appropriate cost of equity is a forward-looking concept. It is the expected return, not the actual return that may prevail in some future period. As a measure of

opportunity cost, it is the return required to attract investors' funds. (Staff/200, Morgan/24, lines 10-13)

- A principle of financial theory is that investors expect a higher return as compensation for taking on higher risk on financial assets. Conversely, the lower the risk, the lower the expected return. However, this principle should also be placed in the context of broader cost of capital concepts. Two such concepts are the relationship between operating position, capital structure, and bond ratings; and the relationship between capital structure and the cost of equity. (Staff/200, Morgan/18, lines 2-9)

Q. What cost of capital concept did Mr. Morgan not fully explain in the theory you summarize above?

A. Mr. Morgan notes that capital structure affects the cost of equity. We agree: *Brigham*[1] and others have shown that as the firm's capital structure changes, so does its cost of capital. But Mr. Morgan does not fully explain, that the higher the amount of debt in a company's capital structure, the higher its cost of equity.

Q. What are the implications of this principle for Oregon Electric?

A. All else being equal, because Oregon Electric's capital structure has a greater percentage of debt than PGE's, Oregon Electric's cost of equity would be higher than PGE's.

Q. How does this implication relate to Mr. Morgan's conclusions about double leverage?

A. Mr. Morgan appears to assume that Oregon Electric's cost of equity capital is the same as PGE's. He thus discusses double leverage as a benefit to Oregon Electric and argues that the tax deduction available for interest payments on Oregon Electric's debt is the economic equivalent of a "free lunch" to Oregon Electric.

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[1] Brigham, Eugene, <u>Fundamentals of Financial Management, Sixth Edition</u>, Dryden Press, Chapter 11.

Q. Does an increasing amount of debt in the capital structure increase the cost of equity?

A. Yes, the cost of equity would increase. As the company acquires more debt, unsecured investors (e.g., equity holders) will demand a higher return because there are fewer assets available for their claims if the firm should go bankrupt. Generally, stockholders receive the residual value of the firm, after all debt holders and other creditors have been paid. Thus, the more assets that the company has mortgaged (i.e., the more debt in the capital structure), the less residual value that is available to equityholders and the higher the return they will demand.

Q. Has the OPUC recognized the principle linking capital structure and the cost of equity?

A. Yes. In Docket UE-115, the Commission recognized the effect of the amount of debt in a capital structure on the cost of equity and applied this principle to lower PGE's cost of equity because of the relatively low percentage of debt in PGE's test year capital structure. Specifically, in OPUC Order No. 01-777, the Commission noted that PGE's regulated equity was 52.16% while the average for the comparable group of electric utilities was 45.14%. The Commission stated: "PGE's capital structure is therefore less risky, and its cost of common equity should be adjusted accordingly." The Commission lowered PGE's authorized ROE from 10.75% to 10.50% to reflect PGE's higher equity ratio.

Q. Do you agree with Mr. Morgan's assumption about Oregon Electric's cost of equity capital?

A. No, we do not. Mr. Morgan has made no attempt to determine the proper, forward-looking, cost of equity for Oregon Electric. Given the amount of debt that resides at Oregon Electric for which Oregon Electric's owners -- not PGE or PGE's customers – are liable, we do not agree that the required cost of equity for Oregon Electric is the same or lower than that for PGE.

Q. What return will Oregon Electric receive on its investment in PGE stock?

A. Oregon Electric has the opportunity to receive 10.5% on PGE's book equity of its ratebase through its investment in PGE stock (assuming that PGE actually earns its allowed ROE), and this investment would be funded by both debt and equity. This is PGE's authorized return on equity set in our last general rate case, UE-115, for the 2002 test year. Naturally, as actual economic and other conditions vary from those assumed for the test year, the actual return on PGE's equity will also vary.

Q. If Oregon Electric is allowed to earn 10.5% on its investment in PGE stock, what does this imply regarding Oregon Electric's required return on equity?

A. Oregon Electric's required return on equity will be higher than PGE's authorized 10.5%.

Q. Would you please demonstrate that Oregon electric's required return on equity must be higher than PGE's 10.5% authorized rate?

A. Certainly. The weighted cost of capital (or rate of return) can be written as:

$$CoC = (R_E * E) + (R_D * D)*(1\text{-}t)$$

Where

R_E = Cost of Equity

R_D = Cost of Debt

E = Proportion of equity in the capital structure

D = Proportion of debt in the capital structure

t = tax rate

We know that Oregon Electric's expected return would be 10.5% on its investment in PGE's stock, assuming that the price is close to the equity component of PGE's ratebase . We also know that Oregon Electric's capital structure at closing will be approximately $707 million in debt and $525 million in equity. For illustrative purposes, we assume that Oregon

Electric's cost of debt is approximately 7.5% and its tax rate is approximately 40%. Using these assumptions, we can use the above equation to calculate Oregon Electric's implied return on equity:

$$10.5\% = (R_E * 43\%) + (7.5\% * 57\%)*(1- 40\%)$$

$$R_E = 19\%$$

Clearly, while this calculation is illustrative, it shows that Oregon Electric's required return on equity is higher than PGE's. Naturally, changing any of the assumptions will change the resultant return on equity for Oregon Electric.

Q. How does your conclusion about Oregon Electric's cost of equity capital affect a discussion of the issue of double leverage?

A. One must consider the effect of capital structure on the cost of equity to begin any comparison of the weighted average cost of capital for one firm with that of another. This is true even if the two firms are parent and subsidiary. Mr. Morgan, and other party witnesses, offer their analyses and critiques of Oregon Electric's double leverage with the unstated assumption that Oregon Electric's cost of equity capital is the same as PGE's. It is not. Oregon Electric's cost of equity is higher.

Q. Please explain further.

A. All of these witnesses imply that double leverage is an economic "free lunch." This is true only if you believe that an investor requires no compensation for risk. But that is not consistent with financial theory or the marketplace. The cost of equity is different under different capital structures because the risk is different to the equity holder across different capital structures. The more an investor borrows to make an investment, the more risk he or she faces. That investor's cost of capital is higher because there is more debt which is entitled to be paid before the equity receives any proceeds. This is true whether the investment is a house or a share of stock and whether the investor is an individual, an institution, or a fund. Moreover, the witnesses appear to believe that all previous holders of Portland General Corporation stock, prior to Enron's ownership, paid for their shares without any use of borrowed funds. This is not realistic. Even individual stockholders may use borrowed funds to support their overall expenditure and investment levels. "Double leverage" may exist in part whether the corporation is owned by many shareholders who trade their shares on a public exchange, or by one or a few shareholders who own equity in a privately held company.

Q. How does the parties' misconception of double leverage relate to their portrayal of the tax deduction for interest on debt held at Oregon Electric as a "savings?"

A. By assuming that Oregon Electric's cost of equity is the same as PGE's, they then reach the conclusion that Oregon Electric's weighted after-tax cost of capital is lower than PGE's because of the tax effects of the debt. They portray this as unfair because PGE's customers pay prices based on a revenue requirement that includes PGE's higher – according to them – weighted after-tax cost of capital. It is also portrayed as unfair because PGE's customers do not receive the benefits of a tax deduction for interest on Oregon Electric debt, for which PGE is not responsible.

Again, most of this is implicit in the concerns and arguments raised. None of the witnesses actually talk about Oregon Electric's weighted after-tax cost of capital. By discussing only the interest deduction that Oregon Electric will obtain, the parties are addressing only one component of its cost of capital. But Oregon Electric's weighted after-tax cost of capital IS actually the question. It is clear that, once one adjusts Oregon

Electric's cost of equity for its capital structure, its weighted after-tax cost of capital would be higher than PGE's. Since it is not lower than PGE's, there are no "savings" here.

Q. If the Commission wanted to address the revenue requirement effects of double leverage and the tax deductibility of interest on debt at a parent company in a way consistent with financial theory, what would it have to do?

A. The question the Commission *could* consider is whether Oregon Electric's total after-tax cost of capital is less than PGE's and, thus, whether the Commission should use Oregon Electric's cost of capital rather than PGE's cost of capital for rate setting purposes. This, of course, is possible for the Commission to consider only because information about Oregon Electric's owners is available, as it would not be for the owners of a publicly-traded utility. However, just because the information is available does not mean the Commission should consider it. Oregon Electric and PGE are separate entities, with separate assets and liabilities, and substituting the capital structure and cost of one for the other mixes assumptions in a way inconsistent with most regulatory theory and practice.

Indeed, it would represent a fundamental change in the way the Commission has approached this issue since at least 1985. And, if applied only to PGE and then only if owned by Oregon Electric, would create the anomaly of having different regulatory treatment for ratemaking purposes for each of the two major electric utilities in Oregon. Finally, as we indicated previously, using Oregon Electric's cost of capital instead of PGE's would result in a higher, not lower, revenue requirement and, hence, high retail rates. For all of these reasons, we do not recommend that the Commission use Oregon Electric's cost of capital to establish PGE's revenue requirement.

III. Taxes and Tax Structure

A. Estimating Income Taxes

Q. What testimony are you addressing or rebutting in this section?

A. We are supplementing the explanation of the rate making treatment of taxes that Staff witness Judy Johnson provides. We rebut the parties, such as Bob Jenks and Lowrey Brown of CUB, who argue that the Commission should treat the tax effects of debt held at Oregon Electric as a "cost" of this transaction to customers or otherwise credit customers with these "savings."

Q. What income taxes does PGE forecast for revenue requirement purposes?

A. PGE forecasts two types of income tax expense: state and federal tax expense. State tax expense represents an estimate of tax expense attributable to taxable income from state taxing authorities that have jurisdiction over PGE. Those states include Oregon, Washington, and Montana. We reduce our estimates of state tax expense to reflect the estimated amortization of available state tax credits.

Federal tax expense represents an estimate of tax expense attributable to taxable income from the federal government. Estimates of federal tax expense are reduced to reflect the estimated amortization of certain investment tax credits.

Q. When does PGE forecast or model income taxes?

A. We forecast income taxes whenever we estimate revenue requirements for PGE. For example, when we file a general rate case, we project PGE's costs for a future test year. Part of our cost projection for the test year includes our estimates for income taxes, both current and deferred. PGE Exhibit 201 is a copy of the forecast for the 2002 test year in our last general rate case, UE-115.

We also model income taxes when we estimate our regulated results of operations, which we provide to the OPUC annually. In this case, we look back at the most recent calendar year and perform various adjustments to transform our actual financial results into a regulated perspective. A copy of our most recent Regulated Results of Operation report is PGE Exhibit 202.

In all cases, we model PGE income taxes on a "stand alone" basis for regulatory purposes. We remove all tax effects from PGE's unregulated operations as well as from subsidiaries and our parent company, as appropriate.

Q. Does PGE further differentiate tax expense in modeling income taxes?

A. Yes. Income taxes are further broken down between current income taxes and deferred income taxes. This differentiation applies to both estimated state and federal income tax expense.

Q. What is current income tax expense?

A. Current income tax expense represents the taxes that we would expect to pay currently to the various taxing authorities on a stand-alone basis as a result of taxable income.

Q. How does PGE forecast current taxes for revenue requirement purposes?

A. PGE forecasts current taxes for revenue requirement purposes on the basis of forecasted book taxable income, adjusted for certain items that can be deducted for income tax purposes on a more accelerated basis, most notably plant depreciation expense.

Q. What is deferred income tax expense?

A. Deferred income tax expense represents the taxes that we would expect to pay to the various taxing authorities on a stand-alone basis in future periods, but must be accrued for currently, as a result of taxable income.

Q. How does PGE forecast deferred taxes for revenue requirement purposes?

A. PGE forecasts deferred income taxes for revenue requirement purposes on the basis of the difference between the accelerated deductions taken for tax purposes and those taken for book tax expense. Again, these differences relate predominantly to accelerated depreciation on plant for tax purposes.

Q. Are there any other items that PGE forecasts in modeling income taxes?

A. Yes. PGE maintains separate records for plant that was placed in service prior to the full normalization of book-tax differences (i.e., establishing deferred taxes) that occurred in 1981. For the pre-1981 plant vintages, PGE forecasts current tax expense related to the reversals of prior-period "flow-through" benefits associated with accelerated depreciation for tax purposes.

B. Tax Issues

1. Regulatory Treatment of Income Taxes

Q. Ms. Johnson has testified that OPUC policy has been to treat a utility on a "stand alone" basis for regulatory purposes. Do you agree with her testimony?

A. Generally, we agree with Ms. Johnson's testimony. However, we have two minor disagreements regarding tax structure and normalization. The tax "flow-through" and "normalization" issues are very complex and elements of both can be found on most electric utility books. Our purpose here is to provide some qualifications to Staff's testimony on normalization.

Q. Ms. Johnson has testified that Oregon Electric will be structured differently than the other regulated energy utilities in Oregon. Do you agree?

A. No. First, while it is true that the Oregon Electric's structure will contain only one subsidiary (PGE), that subsidiary has several subsidiaries. Thus, the organizational structure is actually composed of several subsidiaries, as shown in PGE Exhibit 204. This is not markedly different from the corporate structure that existed when Portland General Corporation held PGE, or from the corporate structure of several other Oregon utilities, such as PacifiCorp or Idaho Power Company.

Second, from a utility income tax reporting and rate making perspective, Oregon Electric's structure is similar to the structure used by the other Oregon energy utilities. For income tax and rate making purposes, it should make no difference whether a parent company has only one subsidiary, or many. The income tax reporting and ratemaking treatment should be the same regardless of the number of consolidated subsidiaries.

<u>2. IRS Issues</u>

Q. Staff testified that IRS rules require "normalization." Do you agree?

A. Yes, the IRS requires normalization. If the Commission adopts ratemaking and true-up mechanisms to ensure that Oregon utility customers pay only what the utilities from whom they take service pay to the taxing authorities, such mechanisms would violate the IRS normalization requirements. This is because the mechanisms would serve to pass through immediately to customers the benefits of accelerated depreciation.

That being said, to clarify a technical point, regulatory mechanisms that serve *only* to reflect in a utility's revenue requirement the tax effects of the interest deduction at a parent company would not necessarily violate normalization requirements. There are other legal and regulatory policy issues with such regulatory mechanisms, some of which we discussed in Section II above, but the normalization rules are not among them.

Q. Would you please briefly explain the IRS "normalization" requirements?

A. Certainly. The IRS normalization requirements are rooted in Internal Revenue Code Section 168(f)(2): (This Code Section does not apply to) ... public utility property... if the taxpayer does not use a normalization method of accounting. The regulations under this Code Section require rate making and accounting methods that spread the tax benefits of tax depreciation over the ratemaking life of the asset. The regulations are detailed and complex. Regulators are permitted to treat the accumulated deferred tax as cost-free capital, which is accomplished in Oregon by using the accumulated balance of deferred taxes as an offset to rate base.

Q. How have "normalization" requirements affected ratemaking recognition of consolidated tax effects?

A. The IRS issued several letter rulings in the 1980s concluding that capturing parent company tax savings associated with consolidated tax returns for ratemaking purposes constituted a violation of the normalization requirements. The Pennsylvania Public Utilities Commission (PPUC) refused to follow one of these rulings in its decision regarding Continental Telephone Company (Contel). A Pennsylvania state court agreed, rejecting the IRS's letter ruling that Contel would be in violation of the normalization rules if it followed the OPUC's rate order.

In 1990, the IRS proposed regulations stating that the use by regulators of consolidated tax savings for ratemaking purposes would result in the utility losing the use of accelerated depreciation. After receiving 100 written comments and holding a public hearing, the IRS withdrew the proposed regulations on April 25, 1991. Mr. Michael J. Graetz, then Deputy Secretary for Tax Policy at the Treasury Department, provided testimony before the Select

Revenue Measures of the House Ways and Means Committee on September 11, 1991 on the proposed and withdrawn regulations. His testimony indicated that the IRS, if requested in an appropriate circumstance, would rule that consolidated tax adjustments do not violate the normalization requirements. Several members of the Committee suggested congressional action should be taken to prohibit utilization of consolidated tax benefits in the ratemaking process. No legislative action or rulings have since been issued on this subject.

Q. Would trying to regulate PGE on a different basis than "stand alone" be difficult?

A. Yes. Attempting to capture tax benefits outside the regulated utility is complex and presents potential costs and risks to customers. Foremost of these is that, to be equitable, ratemaking would need to also reflect tax liabilities that exist outside of the regulated utility. Moreover, income taxes are simply one component of taxable income. If the Commission decides that utilities and parent companies should consolidate for ratemaking purposes, then the Commission should also accept the parent company's revenue and expenses on which the taxes are based as appropriate for setting the utility's revenue requirement, regardless of whether those revenues and expenses relate to regulated operations or not. This would include, among other things, the consolidated capital structure at Oregon Electric, the associated costs of debt and equity, Oregon Electric's operating expenses, and any liabilities or other obligations at Oregon Electric.

In a March 24, 2003 recommendation (Exhibit 205) to the Commission recommending that the Commission deny URP's request to open a investigation regarding PGE's income taxes, Staff attached an excerpt from a text titled Accounting for Public Utilities. This text explained why a stand-alone approach to ratemaking is the best regulatory policy:

> "Income tax normalization is consistent with a fundamental principle of the cost of service approach to ratemaking. Under this principle, there is a well-reasoned, and

> widely recognized, postulate that taxes follow the events they give rise to. Thus, if ratepayers are held responsible for costs, they are entitled to the tax benefits associated with the costs. If ratepayers do not bear the costs, they are not entitled to the tax benefits associated with the costs." Accounting for Public Utilities, Publication 016, Release 19, November 2002.

Staff relied on this text in concluding that a stand-alone construct for ratemaking, including treatment of income taxes, was consistent with standard ratemaking practices. Staff also explained that:

> "If PGE's rates were set in a manner that captured some of Enron's tax losses, PGE's rates would also have needed to reflect the expenses that created those tax savings, and customers would be worse off. Staff's 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. Moreover, such an approach may lead to confiscatory rates." Staff Memo at 2-3.

We agree with the text and Staff's conclusions and believe they apply equally to Oregon Electric. As we explained above, to 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 expenses, and all of its other liabilities and obligations. Anything less would be inconsistent.

Q. Are there other issues that may arise if the Commission adopts consolidation as a ratemaking practice?

A. Yes. Another issue is consistency in the treatment of consolidated taxes within an entire utility corporate family and among Oregon utilities. The Commission should apply its consolidated rule not only to Oregon Electric and PGE, but also include PGE's subsidiaries and non-regulated activities. As we noted above, the proposed corporate structure for PGE is not unique among Oregon utilities and any Commission policy change should apply generally to all Oregon utilities.

Q. What is your response to CUB's claim that Commission failure to change its treatment of income taxes for Oregon utilities will result in customers paying taxes that the utility doesn't owe?

A. Looked at on the same basis as all other forecasted revenues and expenses of the utility, this is incorrect. On a stand-alone basis, if all other assumptions held the same (and ignoring for now any difference in the timing of taxes), the tax expense we presently forecast in revenue requirements is the amount of taxes PGE would owe. Furthermore, the amount of taxes that customers will pay in rates *will be exactly the same* whether Oregon Electric or some other entity is the new owner, or if PGE were a publicly traded company. To be very clear, regardless who owns PGE, customer prices should be set to provide PGE an opportunity to recover the same amount of taxes: those taxes PGE would owe on a stand-alone basis, considering the revenue, expense, and net income of PGE on a stand-alone basis. We already addressed how making some other tax assumption would mix revenue requirement elements across entities and should not be attempted at all without a full substitution of Oregon Electric's consolidated cost of capital and other costs for PGE's to be consistent with financial theory.

Moreover, the fact is that the revenues and expenses PGE experiences after a rate case often vary from the amounts assumed. Generally, it is PGE's job to manage these variations until the gap becomes so great to warrant a change – up or down – in rates.

Last, we disagree with characterizations that suggest that customers pay any given expense PGE incurs. Customers pay for the electric service they use. Those rates are based on PGE's expected or forecasted cost of service, which might be quite different than the actual cost of service.

IV. Enron Overheads

Q. What testimony are you rebutting in this section?

A. We are rebutting the claims of CUB witness Dittmer, repeated by CUB witnesses Jenks and Brown, that removing PGE from Enron ownership into Oregon Electric ownership will result in diseconomies of scale that are a "cost" of this transaction and require compensation. We disagree for two reasons:

- As CUB explains several times, Enron is in the process of dissolving and it is a foregone conclusion that an Enron entity will stop providing PGE certain corporate services. To the extent such diseconomies of scale existed, they are going away just as the sun will rise tomorrow.
- 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. This is preliminary estimate and is subject to refinement.

Q. Are there any Enron costs included in PGE's retail rates?

A. Yes. In PGE's last general rate case (OPUC Docket UE-115) that we filed in Fall of 2000, we included expected charges from Enron for the 2002 test year. These charges included direct charges and corporate allocations or overhead. We provided a detailed breakdown of these charges. PGE Exhibit 203 is our testimony from UE-115 regarding the charges from Enron as well as the associated exhibits and work papers.

Q. Please describe how Enron directly charged costs to PGE and other Enron subsidiaries.

A. Enron directly charged corporate costs based on the method most appropriate for the type of service being provided. The preference was for charging costs based on direct measures of use whenever possible, such as use of labor or use of resources. PGE Exhibit 603 in UE-115 summarizes Enron's direct charging methods by service type.

Q. What costs did Enron allocate to PGE and what allocation method did it use?

A. Enron allocated costs for which none of the direct charge methods work. It used the Modified Massachusetts Formula (MMF), a common allocation methodology. The MMF is a three-factor model. The three-factor average determines the MMF factor for the particular subsidiary. The product of the MMF factor and the sum of all costs that cannot be directly charged equals the cost allocated via the MMF method.

Q. How did PGE estimate 2002 test year Enron allocations and direct charges?

A. First, PGE adjusted the 2000 budget of Enron direct charges to reflect PGE's calculations of expected direct charges for certain benefits programs. Next, we escalated the adjusted 2000 budget for two years of expected inflation in direct charges and allocations. Third, we removed certain allocations from the 2002 budget total to reflect traditional regulatory disallowance of these services or to reflect the failure of the services to meet the criteria listed in the PGE/Affiliates Master Service Agreement.

Q. What is the level of Enron charges that are included in PGE's test year?

A. Table 1 below details the direct Enron charges that are included in PGE's 2002 test year. Table 2 provides similar detail for the corporate allocations.

Table 1
Enron Direct Charges for Services

Enron Service	2002 Test Year
HR Services	$25,519,911
IT Services	$3,575,116
Legal Services	$67,043
Risk Mgmt. Services	$364,407
Actg./Tax Services	$1,058,028
Misc. Services	$908,852
Total Direct Charges	$31,493,357

Table 2
Enron MMF Allocations for Services

Enron Service	2002 Test Year
HR Services	$3,056,757
Corporate Communications	$587,677
Investor Relations	$1,306,297
Finance & Actg.	$3,039,996
Executive Services	$1,402,672
Misc. Services	$540,537
Legal/Regulatory	$702,907
Total MMF Allocations	$10,636,843

Q. Since Enron's bankruptcy, has PGE lessened its reliance on Enron Corp for services?

A. Yes. First, beginning January of this year, Enron ceased to charge corporate allocations to PGE. Thus, although we are receiving some services in this category from Enron, PGE is not paying for these services. Second, PGE has reduced the direct services that it receives from Enron and expects to eliminate Human Resources services by the end of this year.

Q. Does PGE expect to use historical Enron corporate allocations as a basis for any costs included in future general rate proceedings?

A. No. When PGE puts together its test year for a general rate case, we begin with PGE's budget for the next calendar year and then escalate that budget to the test year, including known and measurable changes. We do not use historical corporate allocations as a basis for expected test year allocations and, indeed, have already agreed with the OPUC Staff on this point.

Q. What services that Enron previously provided has PGE begun providing for itself?

A. PGE no longer relies upon Enron for any regulated legal services. We provide all regulated legal services either in-house or hire outside lawyers with the necessary expertise. We no longer receive any IT services from Enron, although we are still able to access certain areas of Enron's intranet for benefit information and some industry on-line periodicals. We developed and maintain our own firewall and are in the process of determining whether to subscribe to the industry on-line periodicals. We also receive no risk management services from Enron.

Q. What services does PGE continue to receive from Enron?

A. PGE continues to receive some insurance coverage from Enron, for which we are directly charged. The insurance coverage is for Directors and Officers Liability, Excess General Liability, Fiduciary Liability and Special Crime Coverage. We expect to obtain our own separate coverage by the end of the year. We also receive benefits through Enron, for which we are directly charged. These benefits are for health coverage and for PGE's 401-K. Again, PGE is bringing these services in-house and expects to complete the transition by the end of the year.

Q. Has PGE estimated the cost to replace the services that were previously provided by Enron Corp?

A. Yes, we made a preliminary estimate that suggests that 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. This estimate is preliminary. To refine the estimate, we would have to essentially generate another test-year type budget, which we haven't done. Also, to make the estimates comparable to test-year numbers, we would have to adjust our projection for number of employees, escalation, and several other factors. Again, we haven't performed these calculations.

Q. Does this imply that there are "diseconomies" from separating from Enron?

A. No. Enron will not provide any services to PGE after the end of the year. PGE's stock will either be purchased by TPG or distributed to Enron's creditors. In either scenario, Enron will not provide services to PGE. Thus, the economies associated with being part of the Enron family will no longer be available to PGE. In some cases, the cost of services will rise, such as insurance and benefits administration. In other cases, the cost of services will decrease, such as shareholder services. Enron Corp. provided shareholder services to its subsidiaries but neither Oregon Electric nor PGE will need these services. On 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 cost will be slightly less that the direct and indirect charges allocated to PGE by Enron.

Q. What is your response to Mr. Dittmer's claim that customers should continue to receive at least $9 million a year, for some time, for the promised savings from Enron's ownership of PGE?

A. Mr. Dittmer is mistaken. Enron made this promise in 1997 for a period of four years and customers received credits totaling $36 million. Enron made no other guarantee of savings. We do not understand the basis for Mr. Dittmer's claim.

V. Earnings Sharing Mechanism

Q. What testimony are you responding to in this section?

A. We rebut the claims of Staff and various parties that the earnings sharing mechanism delivers no value for various reasons including that PGE is not earning its allowed rate of return now and that, if savings reduced its costs and produced extra income, customers are already entitled to receive those savings through a general rate case. We also address Staff's claim that the mechanism is "fraught with complications and uncertainty".

We understand Oregon Electric has decided to propose a rate credit in an amount certain rather than continuing to propose an earnings sharing mechanism in order to respond to the concerns of Staff and others that the sharing mechanism was too uncertain. However, we understand the principal behind the fixed amount rate credit, remains profit sharing and therefore appropriate to present this testimony on the efficacy of the earnings sharing proposal.

Q. Please describe the earnings sharing mechanism proposed by Applicants.

A. The earnings sharing mechanism credits customers with a percentage of any excess earnings, on a regulated basis, above PGE's authorized ROE of 10.5%.

Q. Does the earnings sharing mechanism provide benefits not necessarily captured in a general rate case test year?

A. Yes. The earnings sharing mechanism captures benefits for customers in two separate ways that are not achievable through general rate cases. The first is net income related to variables that we normalize for ratemaking purposes, which we would not normalize for purposes of applying this mechanism.[2] The second is net income generated through

[2] Applicants noted in proposing this mechanism that care would have to be taken with the treatment of variation in hydro-electric production because of the significant financial effects associated with this variation. If the

sustainable cost savings or productivity improvements that will not be reflected in a general rate case revenue requirement for some time. We discuss each below.

Income above that attributable to PGE's allowed rate of return can often relate to variances in assumptions that we typically normalize for ratemaking purposes. In a general rate case, we develop expected costs or revenue requirements for a future test year. For the future test year, we assume "normality" in operations and everything else, unless we have evidence to the contrary. For example, we assume normal weather and normal power plant operations (plant availability). We also assume a normal pattern of storms for outages. To the extent that any of these factors turn out to be different than normal, PGE's actual results will differ. The rule against retroactive rate making prevents capture of past earnings based on these variables. Even if PGE were to have a general rate case immediately after a year in which its income was higher because of, for example, weather, rates would not necessarily reflect any change in normal weather. Although a general rate case would update generating plant performance, Oregon has for many years used a rolling four-year average for purposes of calculating availability factors. Thus any effect of this variance would be much diluted.

PGE witness Piro explains the circumstances and events that can affect PGE's net income. The earnings sharing mechanism gives customers a share of the upside of these risks, with no corresponding downside, in a way totally complementary to the general rate case process. We find simply false the parties' argument that this is not a benefit because customers would get it all anyway.

Second, to the extent PGE's income reflects cost savings programs or productivity improvements, these variances generally occur slowly over a number of years. Several

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Commission adopted PGE's hydro adjustment tariff, no normalization would be necessary to apply this mechanism. If the Commission does not adopt that tariff, further work would need to occur to make this mechanism fair and years could go by before the cumulative effects would warrant a general rate case, whether initiated by the Commission or PGE.

The earnings sharing mechanism proposed by Applicants would capture these benefits to the extent that they result in any excess regulated earnings by PGE on an annual basis.

Q. Would the earnings sharing mechanism be difficult to administer?

A. No. PGE files a, Results of Operations report, on an annual basis with the OPUC. This report begins with PGE's actual financial results, consistent with our SEC filed financial statements, and makes adjustments to those results to develop PGE's financial performance on a regulated basis, consistent with the determinations made in our last general rate case (i.e., UE-115). This is precisely the base number we would need for the earnings sharing mechanism. Thus, the earnings sharing mechanism would use an OPUC filing that PGE already is required to make and with which Staff is very familiar.

PGE would also not make the typical normalizing adjustments to financial results, i.e., normal weather, normal plant operations. As we indicated above, however, some normalization of hydro conditions may be necessary if the Commission did not accept PGE's hydro adjustment tariff. Without normalization, the mechanism will capture the upside benefits of positive variances from normal, and be easier to apply. PGE Exhibit 204 summarizes the adjustments PGE would propose to make to our actual financial results for purposes of the earnings sharing mechanism, assuming acceptance of our hydro adjustment mechanism.

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workable given hydro variations.

VI. Qualifications

Q. Mr. Tinker, please describe your qualifications.

A. I received a Bachelor of Science degree in Finance and Economics from Portland State University in 1993 and a Master of Science degree in Economics from Portland State University in 1995. In 1999, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department since joining PGE in1996.

Q. Mr. Murray, please describe your qualifications.

A. I received both Bachelors of Science in Business Administration degree in 1968 and Masters of Taxation degree in 1987, both from Portland State University. I have been licensed as a Certified Public Accountant in Oregon since 1972.

I serve as Portland General Electric Company's Tax Director since 2000. Previously, I was the Managing Tax Director of PacifiCorp for nearly 20 years. In both positions, I am/was responsible for preparation, payment, and recording of income and property taxes.

I currently serve on the International Board of Directors of Tax Executives Institute (TEI), an association of 5,000 corporate tax executives. I am a past President of this association, and have designed and delivered courses of education for members of TEI. During 1999 and 2000, I served on the Internal Revenue Service Advisory Council, chairing the Large Business Subcommittee in 2000. I am also a member of the American Institute of Certified Public Accountants and the Oregon Society of Certified Public Accountants.

Q. Mr. Hager, please describe your qualifications.

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975 and a Master of Arts degree in Economics from the University of California at Davis in

1978. In 1995, I passed the examination for the Certified Rate of Return Analyst (CRRA). In 2000, I obtained the Chartered Financial Analyst (CFA) designation. I have taught several introductory and intermediate classes in economics at the University of California at Davis and at California State University Sacramento. In addition, I taught intermediate finance classes at Portland State University.

I have been employed at PGE since 1984, beginning as a business analyst. I have worked in a variety of positions at PGE since 1984, including power supply. My current position is Manager, Regulatory Affairs. I am responsible for determining PGE's revenue requirements as well as estimating PGE's Required Return on Equity.

Q. Does this conclude your testimony?

A. Yes.

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List of Exhibits

PGE Exhibit	Description
201	Revenue Requirement Forecast for UE-115 (2002 Test Year)
202	2002 Regulated Results of Operation Report
203	PGE UE-115 Testimony on Corporate Allocations
204	Summary of Adjustments for Earnings Sharing Mechanism
205	OPUC Order No. 03-214

2002 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	2002 Results At Current Base Rates	Change for Reasonable Return	2002 Results at Adjusted Base Rates
Operating Revenues			
Sales to Consumers (Rev. Req.)	1,128,504	323,982	1,452,486
Sales for Resale	-		-
Other Operating Revenues	15,236		15,236
Total Operating Revenues	1,143,740	323,982	1,467,721
Operation & Maintenance			
Net Variable Power Cost	627,942		627,942
Total Fixed O&M	133,074		133,074
Other O&M	161,713	1,620	163,333
Total Operation & Maintenance	922,730	1,620	924,349
Depreciation & Amortization	200,914		200,914
Other Taxes / Franchise Fee	66,318		66,318
Income Taxes	(35,763)	127,013	91,251
Total Oper. Expenses & Taxes	1,154,199	128,633	1,282,832
Utility Operating Income	(10,459)	195,348	184,889
Rate of Return	-0.55%		9.737%
Return on Equity	-8.23%		11.500%

2002 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	2002 Results At Current Base Rates	Change for Reasonable Return	2002 Results at Adjusted Base Rates
Average Rate Base			
Utility Plant in Service	3,636,902		3,636,902
Accumulated Depreciation	(1,757,582)		(1,757,582)
Accumulated Def. Income Taxes	(165,850)		(165,850)
Accumulated Def. Inv. Tax Credit	(25,599)		(25,599)
Net Utility Plant	1,687,870		1,687,870
Net Trojan Investment	137,738		137,738
Weatherization Investment	-		-
Deferred Programs & Investments	22,371		22,371
Operating Materials & Fuel	37,659		37,659
Misc. Deferred Credits	(44,074)		(44,074)
Working Cash	51,477	5,737	57,214
Total Average Rate Base	1,893,042	5,737	1,898,779
Income Tax Calculations			
Book Revenues	1,143,740	323,982	1,467,721
Book Expenses	1,189,961	1,620	1,191,581
Interest Rate Base @ Weighted Cost of Debt	68,353	207	68,560
Temporary Sch M Differences	(38,734)	-	(38,734)
Permanent M Differences	(28,648)	-	(28,648)
State Taxable Income	(47,193)	322,155	274,962
State Income Tax @ 6.81%	(3,214)	21,937	18,724
Federal Taxable Income	(43,979)	300,217	256,238
Fed Tax @ 35%	(15,393)	105,076	89,683
Deferred Taxes	(15,272)	-	(15,272)
ITC Amort	(1,885)	-	(1,885)
Total Income Tax	(35,763)	127,013	91,251

PGE
Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204

June 1, 2004

Ed Busch
Administrator, Electric and Natural Gas Division
Public Utility Commission of Oregon
550 Capitol St. NE Ste. 215
P.O. Box 2148
Salem, Oregon 97308-2148

Re: PGE's Regulated Results of Operations for 2003

Ed:

Enclosed are five copies of the Regulated Results of Operations Report for the period January 1, 2003 to December 31, 2003. Two copies of the summary work papers are also included. For this year's report, we re-categorized one adjustment from the Type II group into the Type I group. Additionally, earnings test adjusted results and pro forma results are based on normalized power costs.

In 2003, PGE and our customers continued to be challenged by a poor economy in Oregon. In addition, PGE faced low hydro conditions, low retail loads, and higher power costs. Some of the major challenges and highlights:

- PGE's annual operating revenue decreased $110 million due to several factors.
    - An average retail rate decrease of 12% became effective January 1, 2003 due to a change in the RVM for 2003 (revenue reduction of $164 million).
    - Loads were down from 2002. They remain lower than forecast for 2002 in UE-115.
        - Three of our largest customers purchased 23% less power than in 2002 ($42.5 million).
        - Some customer loads were curtailed and one large customer moved to cogeneration ($23.5 million).

- Operating expenses in 2002 are not directly comparable to those of 2003. For 2002, we did not normalize for PGE generation because a Power Cost Adjustment (PCA) mechanism was in effect during 2002. However, purchased power cost was higher than expected on a per MWh basis (driven by adverse hydro conditions, and increased wholesale power and gas prices) with aggregate cost tempered by lower loads.

- Depreciation and Amortization increased by about $52 million. These included:
    - $39.9 million was due to amortization credits to customers that expired in 2002 or early 2003
        - Amortization under Tariff Schedule 126 represented certain credits related to NEIL, EPRI and WTC ($23.3 million in 2002).
        - Amortization amounts under Tariff 105 represented deferred gains on Nonrecurring Property Sales, amounts on the Trojan Settlement, and Colstrip sale costs ($8.5 million in 2002).
        - Amortization of Merger Savings Obligation under Tariff 110 represented the remaining refund liability to retail customers related to merger cost savings ($8.1 million in 2002).
    - Other increases were due to increased activity in 2003 over 2002:
        - Amortization increased by $8.2 million, related to deferred SB1149 costs.
        - Amortization increased by $4.3 million, related to the sale of Pelton Round Butte to the Tribes of Warm Springs, reflecting that the sale price did not include recovery of prior year income tax benefits flowed to customers.

- Overall tax costs decreased by $14 million due to lower pretax income.

- In spite of significantly adverse conditions, PGE employees
    - met all of our service quality and safety program requirements;
    - completed equipment/system upgrades at Beaver and Pelton;
    - successfully finished loading Trojan's spent nuclear fuel into the dry cask storage facility; and
    - implemented several new systems including a supply chain management program, an outage management system, and a time collection system.

Table 1 compares 2003 to 2002 regulated financial results and to those anticipated in our last general rate case. From 2003, PGE's utility operating income increased slightly by $1.5 million (about 1%) in spite of the fact that retail revenues were down due to an RVM that set power costs lower than actual. PGE was able to control its operating expenses to minimize the reduction in ROE (to -0.4%).

PGE's 2003 earnings test ROE (i.e., with UE-115 regulatory adjustments) is 7.69%. This is ten basis points lower than last year, and over 280 basis points lower than our authorized ROE. This is also the third consecutive year that our regulated ROE has fallen and remains significantly below its authorized ROE.

Table 1
Earnings Test Adjusted Results
2003, 2002, and UE-115 (TY2002)

	2003 Results	2002 Results	UE-115 TY2002
Operating Revenues			
Sales to Consumers	1,338,620	1,468,343	1,503,222
Sales for Resale	0	0	0
Other Operating Revenues	17,153	(2,913)	15,969
Total Operating Revenues	1,355,772	1,465,430	1,519,191
Operation & Maintenance			
Net Variable Power Cost	607,491	760,119	757,921
Fixed Plant Cost	66,125	68,747	70,458
Transmission	5,396	5,963	6,273
Distribution	45,721	43,608	56,968
Total Fixed O&M	117,241	118,318	133,699
Customer Accounts / Bad Debt	47,594	42,261	37,088
Customer Service & Sales	9,945	16,032	7,377
Admin. & General / OPUC Fee	89,908	87,334	93,980
Other O&M	147,447	145,627	138,445
Total Operation & Maintenance	872,179	1,024,064	1,030,065
Depreciation & Amortization	212,805	160,777	178,593
Other Taxes / Franchise Fee	71,479	68,384	75,093
Income Taxes	60,556	74,937	74,981
Total Oper. Expenses & Taxes	1,217,018	1,328,163	1,358,732
Utility Operating Income	138,754	137,267	160,458
Rate Base	1,769,546	1,727,669	1,766,581
Rate of Return	7.84%	7.95%	9.08%
Return on Equity	7.69%	8.09%	10.50%
Pre interest margin (UOI over Operating Revenues)	10.23%	9.37%	10.56%

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Earlier this year, we filed for a power cost deferral related to expected lost hydro generation. Our forecast not only shows poor runoff thus far, but also poor precipitation in the winter and spring. Our concern is growing because our ROE has fallen for several years and is much lower than authorized.

Recently, we filed a new hydro deferral tariff mechanism that may address some of the concerns voiced by various parties in recent power cost deferral proceedings. The new mechanism targets the cost effects of hydropower, rather than overall changes in net variable power costs. The new proposal relies upon market prices for replacement energy and it will smooth the timing of rate changes for customers.

For 2004, we expect that the local and state economies will continue to improve. However, earnings will remain a concern because natural gas prices are much higher than expected, wholesale electric prices are higher, and hydro conditions continue to be extremely poor.

We continue to evaluate our need to file for a general rate increase. The critical factors are:

- **The success of our efforts to manage controllable O&M expenses.** We reduced Fixed Plant Costs, Customer Support/Marketing/Sales costs, and various costs of operation in 2003; and reduced or reallocated our employee force by 28 in 2002/03. However, in spite of these changes, other areas with increasing costs outweighed the savings. We experienced storm restoration costs from four storms during fourth quarter 2003 and continued growth in employee benefit costs. As always, PGE will continue to look for ways to reduce O&M costs.
- **Recovery in the Oregon economy.** We presently forecast that we will reach the electric load projected for the 2002 UE-115 test year in 2007.

Even assuming a favorable outcome from these two factors, the forces that drive the cost per MWh and other costs upward may become more problematic as we continue to manage the earnings drag created by continued reduced load coupled with poor hydro conditions.

While we await the Commission's decisions on the pending deferral applications, we continue to believe that our next general rate case will most likely be filed in accordance with the timing of any major resource additions. PGE may file earlier if our earnings continue to fall below our authorized ROE of 10.5%.

If you have any questions, please do not hesitate to call me at (503) 464-7580, or Alex Tooman at (503) 464-7623.

Sincerely,

Patrick G. Hager III

Patrick G. Hager
Manager, Regulatory Affairs

encl.
cc: UE-115 Service List
Sharon Noell

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PORTLAND GENERAL ELECTRIC

OPUC REGULATORY REPORTING

RESULTS OF OPERATIONS

January 2003 through December 2003

1. Description of Report

The Results of Operations Report adjusts the calendar year 2003 operating results that PGE reported to investors to provide a regulatory perspective reflecting decisions in the UE-115 proceeding. This provides an "Earnings Test Adjusted Results of Operation." In addition, consistent with the OPUC's reporting guidelines, we make certain "annualizing adjustments" to show operating results adjusted to period-end.

The Results of Operations report was originally intended to provide the Commission with operating results on a comparatively forward-looking basis. Because of the volatility in power and natural gas markets, however, the historic operating environment is less useful in predicting future operating performance.

We normalized 2003 net variable power costs to reflect average hydro conditions, average thermal plant availability, and normal weather. For 2003, we have also improved the groupings of the adjustments by moving one adjustment from the Type II category to the Type I category. We believe that this report format better reflects staff's guidelines, and improves quality/interpretability of the report. We discuss this in Section 1.3 below (Regulatory Adjustments: Type 1).

Had the 2003 Hydro Deferral been approved, PGE's regulated financial performance would have been somewhat improved. We discuss this in section 1.5 below (Sensitivity to Changing Market Conditions).

1.1 Recorded Actuals

Columns 1 through 3 on page 1 of the Results of Operations Report present the recorded actual amounts. Column 1 represents PGE's Financial Statement for External Reporting; column 3 is PGE's Financial Statement for Regulatory Reporting. Section 1.2 discusses the adjustments in column 2.

The General Ledger Detail section of the work papers provides detail for column 1. The first two reports, "Regulated Financial Detail" and "Results of Operations" restate column 1 into rate case format (versus an external reporting format). Pages 4 and 5 summarize and report all utility accounting adjustments (column 2).

The General Ledger Detail work papers also include the monthly detail for constructing the actual Capital Structure and the Average Rate Base. Please note that the Pro Forma ROE calculation is based upon the end-of-period capital structure. All of the data, with the exception of the effective cost of debt, come directly from PGE's General Ledger System. The effective cost of debt includes the cost associated with the debt issuance.

1.2 Utility Accounting Adjustments: Type 1

There are seven accounting adjustments. The adjustments are found on pages 4 and 5, and are described below. Supporting documentation is included in the work papers.

Column 1: Taxes on Carrying Charge Income

This adjustment removes tax effects that result from the interest of deferral amortization, and makes ROE neutral to such amortization. The interest income on regulatory assets is recorded below-the-line in accordance with FERC guidelines. However, PGE has elected to record the income taxes on this interest income above-the-line (since they relate to utility operations and are a "regulatory asset"). This adjustment reclassifies the income taxes to below the line to appropriately match taxes and the income source of the taxes for this regulatory analysis.

Column 2: Regional Power Act (RPA) Reversal

The effects of the RPA settlement are reversed for regulatory analysis. Since these benefits are a "flow-through" item to customers, their effects on tariffs and other revenues are removed.

Column 3: Steam Sales and Sales for Resale

Sales for Resale of $392 million are reclassified from revenues to net variable power costs for this regulatory analysis. Steam Sales of $1.0 million are also reclassified.

Column 4: Remove Wholesale Merchant Trading Margins per Order 97-196 and FAS 133 adjustments

We removed the gross wholesale merchant trading margin on term contracts by matching purchase and sale contracts considered speculative in nature. We removed the support costs for speculative trading so that the trading margin removed represents the margin on a fully allocated cost basis. Incremental costs for the wholesale power marketing function totaled $1.1 million. We also removed FAS 133 and unrealized gains of approximately $26.4 million, offset in part by a FAS 71 adjustment of approximately $16.2 million.

Column 5: Out-of-period and Other Adjustments.

For 2003, seven adjustments are made to reflect extraordinary items and costs from prior periods. In total, four adjustments are applied to NVPC that reduce costs by $32.8 million; and three adjustments are applied to A&G costs that increase costs $3.3 million.

Two of these seven adjustments are applied to reverse adjustments made in the 2002 report. First, $4.6 million is added to purchased power costs to reflect the removal of these costs from amounts posted in 2002 because they related to the 2003 RVM. Second, $4.1 million is added to A&G costs to reflect the removal of severance costs from the amounts posted in 2002 because the associated cost savings are effective in 2003.

Of the remaining five adjustments, three remove power costs: $21.7 million and $1.0 million for reserves taken against receivables, and $14.7 million in contract costs disallowed in UE-139.

The last two adjustments remove costs from A&G: $0.6 million for EE related activity and $0.1 million for activity related to implementation costs for the equal pay settlement.

Column 6: Utility Tax Adjustment (Interest Adjustment)
This adjustment accounts for the differences between PGE Consolidated interest expense and PGE (utility only) interest expense. To accomplish this, we reduce interest expense, and the associated interest deduction for tax purposes. This reduction is made by the proportion of the interest costs allocated to non-rate supported activities The effect of this adjustment is to increase income tax expense. The adjustment is calculated based on the methodology established in UE-79, and continued in UE-88 and UE-115.

Column 7: Pension Credit
PGE's pension performed favorably in 2003, and a pension credit was recorded. This pension fund "income" may be legally used, under ERISA, only for specific pension purposes. This adjustment reverses the $6.2 million in pre-tax income, because it is not available for use against costs of general operation.

1.3 Regulatory Adjustments: Type 1
Pages 6 through 11 contain the regulatory adjustments. Each adjustment is described below and the work papers contain supporting documentation.

Column 1: Normal Water and Plant Operation
This column reflects adjustments for normalizing variable power costs for normal water conditions and PGE plant operations.

The variable power cost adjustment is calculated by taking the difference between actual variable power costs and expected (Normalized water and plant operation) power costs using actual load. Normalized power costs are, however, based on actual fuel prices and market/sale prices.

Market purchase and sale amounts are based on MONET model logic that considers the loads and resources of PGE. Normal water conditions are assumed for the forecast.

Finally, the normalized Monet runs exclude the speculative contracts consistent with the removal of speculative trading margins described in

Section 1.2. This is done to prevent the margins, which are removed from PGE's actual results from being placed back into PGE's Earnings Test Adjusted results through the variable power cost adjustments.

Column 2: Normal Weather

This column reflects adjustments for normalizing weather on both revenues and variable power costs. For example, if the weather produces a load higher than normal (due to colder winter and/or warmer summer) then a negative adjustment to revenues and associated power costs would be made.

Column 3: Two-Cities Sales Revenue

Both the 1991 and prior deferral of "excess power costs" related to the power purchased from BPA have been adjusted to comply with OPUC Order No. 91-186. We make this adjustment per a schedule (of amount and timing) through 2112, in accordance with Appendix C of the Order.

Column 4: Gas Resale Revenues

This adjustment removes revenues from the resale of gas. PGE does not purchase gas for the purpose of reselling it. Under normal conditions (water, weather, etc.) PGE would use all of its supply of gas for the purpose of operating its plants. These sales are removed from PGE's regulated earnings since they are a significant, nonrecurring event, in accordance with the OPUC earning review guidelines of March 25, 1992.

In 2003, this adjustment was moved to this Type I adjustment category. In years when normalization is not appropriate, the adjustments for normal water/plant operations and weather, along with this adjustment are not included. Therefore, moving this adjustment to the Type I category is appropriate and improves the normalization approach.

Column 5: Wage and Salary Adjustment

Order 01-777 adjusted A&G costs based on the three-year wage and salary model. This model was updated, using 2000 as the base year. The model provides equal sharing of pay increases higher than the change in the CPI between customers and the stockholders. This sharing recognizes wage and salary progressions in the work force. Using the model, we removed $1.4 million from A&G expense and $376,000 from rate base.

Column 6: Incentive Pay

This column removes $1.9 million in expense and $460,000 from rate base. These reductions are comprised of 15% of Teamworks incentive pay, 15% of the non-officer ACI incentive pay, and 100% of the Officer ACI incentive pay, in accordance with Order 01-777. (See the three-year wage and salary model in the work papers.) Note: per Order 95-1216 there is no disallowance of incentive pay (ACI or Teamworks) for Coyote Springs personnel due to their unique incentive labor contract.

Column 7: Marketing and Sales

This column adds $1.3 million in expense to the regulated results of operations, which is the amount by which non-labor marketing and sales costs (as identified by PGE ledgers N42217, N42221, N42223, and N42238) are below the historical three-year average (adjusted for inflation). (see Order 01-777, stipulated adjustment S-29).

Column 8: Advertising Categories "A" and "C"

Order 01-777 allowed in base rates only one-eighth of one percent of the test year revenues of Category "A" advertising expenditure and disallowed 100% of Category "C" advertising expenditures. Order 01-777 also specified that amounts of Category "A" advertising expenditure in excess of the approved amount may be deferred for future recovery. Order 03-601 approved deferred accounting for up to $1.0 million of Category "A" advertising expenditure in excess of the approved amount for the period October 1, 2002 through September 30, 2003. A PGE Application for Reauthorization of Certain Advertising Costs for the period October 1, 2003 through September 30, 2004 was filed on September 30, 2003 and is pending Commission decision. This adjustment includes the effect of the deferral. Because the relevant advertising costs do not exceed the allowed amount net o the deferral, no adjustment is applied for 2003.

Column 9: Retail Unbundling

This column removes $176,000 from the regulated results of operations, which is 40% of PGE ledger N44172 as directed by the Commission in Order 01-777. The 40% disallowance represents the amount of costs associated with retail activity in this ledger.

Column 10: Customer Accounts

This column removes $1.4 million from the regulated results of operations. This is the amount by which PGE's non-labor customer accounting costs (excluding ledgers N41331, N41381, N41382, and N41501) exceed the historical three-year average (adjusted for inflation) as directed by the Commission in Order 01-777.

Column 11: Prior Year Tax Adjustment

Per the March 25, 1992 OPUC guidelines, this column increases taxes by $1.2 million to true-up tax entries booked in 2003 for prior years.

Column 12: Blank

Column 13: Supplemental Executive Retirement Plan (SERP)
Commission Orders 95-322 and 01-777 excluded this cost from PGE's revenue requirement. This adjustment removes $1.6 million in costs from regulated results of operations. We reduced rate base by $520,000 to account for the pre-Order 95-322 (April 1, 1995) SERP costs paid by customers.

Column 14: Management Deferred Compensation Plan (MDCP)
Commission Orders 95-322 and 01-777 excluded this cost from revenue requirement. This adjustment removes $4.5 million in costs from regulated results of operations.

Column 15: Blank

In UE-115, PGE agreed to a one-time adjustment (reduction) to the test year workforce. As a result, the forecast for 2002 equaled the actual levels at the end of 2000. This result, however, was not based on a specific formula, and did not result in the reduction of actual employees. Since this was an adjustment to only test year workforce, we do not include an adjustment in this report.

1.4 Annualized Adjustments: Type II
Pages 12 and 13 contain the adjustments for annualization. We describe each adjustment below and provide supporting documentation in the work papers.

Column 1: Period-End Rate Base and Escalation
We adjust rate base accounts to show year-end balances, rather than midyear. We also annualized the following expense items with a half-year of escalation. The escalation rate is based on "CPI, All Items, Urban Consumers" in Global Insight's U.S. Economic Outlook.

* Fixed Plant
* Transmission
* Distribution
* Customer Accounts
* Customer Service and Sales
* Administration and General
* Taxes Other Than Income

The escalation adjustment adds the effects of inflation to those expenses actually incurred by PGE to support its customer base. The escalation of expenses is not designed to account for the increased activities and expenses associated with the addition of new customers throughout the year. End-of-Period Customer costs are discussed in Column 3 below.

Column 2: Blank

Column 3: End-of-Period Annualizing Adjustment

This adjustment estimates the additional costs and revenues that would have occurred if PGE had the year-end number of customers for the entire year. Incremental O&M and retail revenues are estimated based on actual average O&M per customer and PGE's average retail rate for 2003. No annualizing cost adjustment is required for large industrial, large commercial or street-lighting customers. Revenues are added for residential and commercial customers because the decoupling mechanism ended at year-end 1997, per Advice 96-25. The numbers of customers in these categories change slightly due to consolidations or changes among customer classes, but load tends to remain steady.

1.5 Sensitivity to Changing Market Conditions.

In our 2001 report, we provided a sample of the potential impact of plausible changes in power market conditions on PGE's variable power costs and pro forma operating results. We demonstrated that various changes in market prices, gas prices, and hydro availability could result in large changes in variable power costs and ROE. We also demonstrated the effectiveness of a PCA in dampening market effects on PGE's performance.

In our 2002 report, a Commission-approved Power Cost Adjustment (PCA) Mechanism for poor hydro and other power costs was in effect. Therefore, for comparison purposes, after we normalized for water, plant availability and water; we reversed the PCA deferral transactions. Under that alternative view, power costs would have increased by about $36 million and earnings test adjusted ROE would have declined by 183 basis points.

We performed a similar analysis for 2003 to analyze the effect that a PCA would have had on PGE's power costs and regulated earnings. We found that PGE's power costs would have decreased by about $24 million and earnings test adjusted ROE would have risen by 133 basis points.

Had the Commission approved our requested 2003 hydro deferral, our earnings test adjusted ROE would have been 9.02%, which is still considerably lower than our authorized rate. We continue to believe that PGE's current earnings should be considered in light of the risks borne by PGE to obtain those earnings, and the likelihood that those risks and earnings will continue into the future.

1.6 Capital Structure

We used the actual average capital structure for the return on equity calculation. For the pro forma return on equity calculation, we estimated the actual end of period capital structure. The capital structure detail is shown on Page 14. The long-term debt and preferred stock detail are found in the General Ledger Detail section of the work papers.

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SEMI-ANNUAL REPORT OF OPERATIONS

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Work papers are included in a separate attachment.

PORTLAND GENERAL ELECTRIC
OPUC REGULATORY REPORTING
PRELIMINARY RESULTS OF OPERATIONS
January 1, 2003 - December 31, 2003
(Thousands of Dollars)

Regulatory adjustments based on **Docket UE-115, Order 01-777.**	Actual Financial Statements	Type 1 Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Earnings Test Adj. Results	Type II Adjustments	Pro Forma Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Operating Revenues							
Sales to Consumers	1,327,742	0	1,327,742	10,878	1,338,620	4,307	1,342,927
Sales for Resale	392,317	(392,317)	0	0	0	0	0
Other Operating Revenues	31,407	(1,001)	30,406	(13,254)	17,153	0	17,153
Total Operating Revenues	1,751,466	(393,318)	1,358,148	(2,376)	1,355,772	4,307	1,360,080
Operation & Maintenance							
Net Variable Power Cost	1,027,659	(414,888)	612,771	(5,279)	607,491	2,365	609,856
Total Fixed O&M	117,241	0	117,241	0	117,241	2,171	119,412
Other O&M	148,619	8,386	157,006	(9,559)	147,447	1,702	149,149
Total Operation & Maintenance	1,293,519	(406,502)	887,017	(14,838)	872,179	6,238	878,417
Depreciation & Amortization	212,805	0	212,805	0	212,805	1,147	213,952
Other Taxes / Franchise Fee	71,583	0	71,583	(104)	71,479	509	71,988
Income Taxes	49,381	5,712	55,093	5,463	60,556	(1,567)	58,989
Total Oper. Expenses & Taxes	1,627,287	(400,790)	1,226,497	(9,479)	1,217,018	6,327	1,223,345
Utility Operating Income	124,179	7,472	131,651	7,103	138,754	(2,020)	136,734
Rate of Return	7.02%		7.41%		7.84%		7.67%
Return on Equity	6.21%		6.92%		7.69%		7.90%
ROE based on actual capital structure.							
Average Rate Base							
Utility Plant in Service	3,686,819	0	3,686,819	(737)	3,686,081	57,660	3,743,741
Accumulated Depreciation	1,818,202	0	1,818,202	0	1,818,202	45,610	1,863,811
Accumulated Def. Income Taxes	174,157	(7,365)	166,792	4,365	171,157	222	171,378
Accumulated Def. Inv. Tax Credit	18,578	0	18,578	0	18,578	(2,115)	16,463
Net Utility Plant	1,675,882	7,365	1,683,247	(5,102)	1,678,145	13,944	1,692,089
Net Trojan Investment	0	0	0	0	0	0	0
Weatherization Investment	298	0	298	0	298	(192)	106
Deferred Programs & Investments	2,294	0	2,294	(138)	2,156	267	2,423
Operating Materials & Fuel	44,564	0	44,564	0	44,564	682	45,246
Misc. Deferred Credits	(11,575)	0	(11,575)	(520)	(12,096)	(2,549)	(14,645)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0
Working Cash	57,150	(333)	56,817	(338)	56,478	282	56,761
Total Average Rate Base	1,768,613	7,032	1,775,645	(6,099)	1,769,546	12,434	1,781,980

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PORTLAND GENERAL ELECTRIC
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		Actual Financial Statements	Type I Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Earnings Test Adj. Results	Type II Adjustments	Pro Forma Results
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Operating Revenues			(1+2)		(3+4)		(5+6)
1	Residential	557,051	52,655	609,706	11,766	621,473	3,273	624,746
2	Commercial	486,057	2,089	488,146	(712)	487,434	1,034	488,468
3	Industrial	228,998	1,977	230,975	(176)	230,799	0	230,799
4	Other	58,636	(56,721)	1,914	(0)	1,914	0	1,914
5	Unbilled Revenues	(3,000)	0	(3,000)	(1)	(3,001)	0	(3,001)
5	Sales to Consumers	1,327,742	0	1,327,742	10,878	1,338,620	4,307	1,342,927
5a	Sales for Resale	392,317	(392,317)	0	0	0	0	0
6	Other Operating Revenues	31,407	(1,001)	30,406	(13,254)	17,153	0	17,153
7	Total Operating Revenues	1,751,466	(393,318)	1,358,148	(2,376)	1,355,772	4,307	1,360,080
	Operation & Maintenance							
8	Steam VPC	51,869	0	51,869	754	52,623	0	52,623
9	Nuclear VPC	0	0	0	0	0	0	0
10	Gas / Other VPC	62,160	0	62,160	(14,657)	47,503	0	47,503
11	Production	114,029	0	114,029	(13,903)	100,126	0	100,126
12	Purchased Power	852,834	(32,824)	820,010	(7,498)	812,512	2,365	814,877
12a	RPA Exchange	0	0	0	0	0	0	0
13	Sales for Resale	0	(382,065)	(382,065)	14,823	(367,242)	0	(367,242)
14	Wheeling	60,796	0	60,796	1,298	62,094	0	62,094
15	Net Variable Power Cost	1,027,659	(414,888)	612,771	(5,279)	607,491	2,365	609,856
16	Fixed Plant Cost	66,125	0	66,125	0	66,125	754	66,878
17	Transmission	5,396	0	5,396	0	5,396	62	5,457
18	Distribution	45,721	0	45,721	0	45,721	1,355	47,076
19	Total Fixed O&M	117,241	0	117,241	0	117,241	2,171	119,412
20	Customer Accounts / Bad Debt	48,951	0	48,951	(1,357)	47,594	564	48,158
21	Customer Service & Sales	8,596	0	8,596	1,349	9,945	113	10,058
22	Admin. & General / OPUC Fee	91,072	8,386	99,458	(9,551)	89,908	1,025	90,933
23	Other O&M	148,619	8,386	157,006	(9,559)	147,447	1,702	149,149
24	Total Operation & Maintenance	1,293,519	(406,502)	887,017	(14,838)	872,179	6,238	878,417
25	Depreciation & Amortization	212,805	0	212,805	0	212,805	1,147	213,952
26	Other Taxes / Franchise Fee	71,583	0	71,583	(104)	71,479	509	71,988
27	Income Taxes (Non-Federal)	6,216	2,178	8,394	718	9,112	(265)	8,847
28	Federal Income Tax Net of ITC	57,029	10,693	67,721	3,524	71,246	(1,302)	69,944
29	Deferred Income Taxes	(12,404)	0	(12,404)	31	(12,372)	0	(12,372)
30	Current/Deferred Taxes True-up	0	(7,159)	(7,159)	1,189	(5,969)	0	(5,969)
31	I.T.C. Adjustment	(1,461)	0	(1,461)	0	(1,461)	0	(1,461)
32	Total Oper. Expenses & Taxes	1,627,287	(400,790)	1,226,497	(9,479)	1,217,018	6,327	1,223,345
33	Utility Operating Income	124,179	7,472	131,651	7,103	138,754	(2,020)	136,734

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		Actual Financial Statements	Type I Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Earnings Test Adj. Results	Type II Adjustments	Pro Forma Results
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Average Rate Base							
34	Utility Plant in Service	3,686,819	0	3,686,819	(737)	3,686,081	57,660	3,743,741
35	Accumulated Depreciation	1,818,202	0	1,818,202	0	1,818,202	45,610	1,863,811
36	Accumulated Def. Income Taxes	174,157	(7,365)	166,792	4,365	171,157	222	171,378
37	Accumulated Def. Inv. Tax Credit	18,578	0	18,578	0	18,578	(2,115)	16,463
38	Net Utility Plant	1,675,882	7,365	1,683,247	(5,102)	1,678,145	13,944	1,692,089
39	Net Trojan Investment	0	0	0	0	0	0	0
40	Weatherization Investment	298	0	298	0	298	(192)	106
41	Deferred Programs & Investments	2,294	0	2,294	(138)	2,156	267	2,423
42	Operating Materials & Fuel	44,564	0	44,564	0	44,564	682	45,246
43	Misc. Deferred Credits	(11,575)	0	(11,575)	(520)	(12,096)	(2,549)	(14,645)
44	Unamortized Ratepayer Gains	0	0	0	0	0	0	0
45	Working Cash	57,150	(333)	56,817	(338)	56,478	282	56,761
46	Total Average Rate Base	1,768,613	7,032	1,775,645	(6,099)	1,769,546	12,434	1,781,980

			Type I Accounting Adjustments (2)	Type I Adjustments (4)	Type II Adjustments (6)
	Income Tax Calculations				
47	Book Revenues		(393,318)	(2,376)	4,307
48	Book Expenses		(406,502)	(14,942)	7,894
49	Not used		0	0	0
50	Interest Rate Base @ Weighted Cost of Debt		(19,545)	(198)	398
51	Schedule M Differences		0	80	0
52	State Taxable Income		32,729	10,787	(3,985)
53	State Income Tax @	6.6547%	2,178	718	(265)
54	Additional Tax Depreciation		0	0	0
55	Federal Taxable Income		30,551	10,070	(3,720)
56	Fed Tax @ 35%	35.00%	10,693	3,524	(1,302)
57	ITC @ 0%	0	0	0	0
58	Current Federal Tax		10,693	3,524	(1,302)
	ITC Adjustment				
59	Deferral		0	0	0
60	Restoration		0	0	0
61	Deferred Taxes		0	31	0
62	Current/Deferred Taxes True-up		(7,159)	1,189	0
63	Total Income Tax		5,712	5,463	(1,567)

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UTILITY ACCOUNTING ADJUSTMENTS

	Type I Adjustments	Taxes on Carrying Chge Income	RPA	Steam Sales and Sales-for-Resale	FAS+Remove NonReg Trading Ord. 97-196	Out of Per and other Adjs	Utility Tax Adj.	Remove Pension Credit	Total
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Operating Revenues								
1	Residential		52,655						52,655
2	Commercial		2,089						2,089
3	Industrial		1,977						1,977
4	Other Revenue		(56,721)						(56,721)
5	Unbilled Revenues								0
5	Sales to Consumers	0	0	0	0	0	0	0	0
5a	Sales for Resale			(392,317)					(392,317)
6	Other Operating Revenues			(1,001)		0			(1,001)
7	Total Operating Revenues	0	0	(393,318)	0	0	0	0	(393,318)
	Operation & Maintenance								
8	Steam								0
9	Nuclear								0
10	Other								0
11	Production	0	0	0	0	0	0	0	0
12	Purchased Power					(32,824)			(32,824)
12a	RPA Exchange		0						0
13	Sales for Resale			(393,318)	11,253				(382,065)
14	Wheeling								0
15	Net Variable Power Cost	0	0	(393,318)	11,253	(32,824)	0	0	(414,888)
16	Fixed Plant Cost								0
17	Transmission								0
18	Distribution								0
19	Total Fixed O&M	0	0	0	0	0	0	0	0
20	Customer Accounts								0
21	Customer Service & Sales								0
22	Administration & General				(1,094)	3,312		6,168	8,386
23	Other O&M	0	0	0	(1,094)	3,312	0	6,168	8,386
24	Total Operation & Maintenance	0	0	(393,318)	10,159	(29,511)	0	6,168	(406,502)
25	Depreciation & Amortization								0
26	Taxes Other than Income								0
27	Inc. Taxes (Non-Federal)	(16)	0	0	(677)	1,966	1,316	(411)	2,178
28	Federal Inc. Tax Net of ITC	(80)	0	0	(3,322)	9,651	6,461	(2,017)	10,693
29	Deferred Income Taxes	0	0	0	0	0	0	0	0
30	Current/Deferred Taxes True-up	(7,159)							(7,159)
31	I.T.C. Adjustment	0	0	0	0	0	0	0	0
32	Total Oper. Exp. & Taxes	(7,255)	0	(393,318)	6,160	(17,895)	7,777	3,740	(400,790)
33	Utility Operating Income	7,255	0	0	(6,160)	17,895	(7,777)	(3,740)	7,472

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UTILITY ACCOUNTING ADJUSTMENTS

	Type I Adjustments	Taxes on Carrying Chge Income	RPA	Steam Sales and Sales-for-Resale	FAS+Remove - NonReg Trading Ord. 97-196	Out of Per and other Adjs	Utility Tax Adj.	Remove Pension Credit	Total
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Average Rate Base								
34	Utility Plant in Service								0
35	Accumulated Depreciation								0
36	Acc Def. Income Taxes	(7,365)							(7,365)
37	Acc Def. Inv. Tax Credit								0
38	Net Utility Plant	7,365	0	0	0		0		7,365
39	-----								0
40	Net Trojan Investment								0
41	Weatherization Investment								0
42	Deferred Programs & Investments								0
43	Operating Materials & Fuel								0
44	Misc. Deferred Credits								0
45	Unamortized Ratepayer Gains								0
46	Working Cash	(324)	n/a	n/a	275	(798)	347	167	(333)
47	Total Average Rate Base	7,041	0	0	275	(798)	347	167	7,032
	Income Tax Calculations								
48	Book Revenues	0	0	(393,318)	0	0	0	0	(393,318)
49	Book Expenses	0	0	(393,318)	10,159	(29,511)	0	6,168	(406,502)
50	Not used.								0
51	Int. R-Base @ Wtd Cost of Debt	245	0	0	10	(28)	(19,777)	6	(19,545)
52	Schedule M Differences	0	0	0	0	0	0	0	0
53	State Taxable Income	(245)	0	0	(10,169)	29,539	19,777	(6,174)	32,729
54	State Tax 6.6547%	(16)	0	0	(677)	1,966	1,316	(411)	2,178
55	Additional Tax Depreciation	0	0	0	0	0		0	0
56	Federal Taxable Income	(228)	0	0	(9,492)	27,573	18,461	(5,763)	30,551
57	Fed Tax 35%	(80)	0	0	(3,322)	9,651	6,461	(2,017)	10,693
58	ITC @ 0%	0	0	0	0	0	0	0	0
59	Current Federal Tax	(80)	0	0	(3,322)	9,651	6,461	(2,017)	10,693
	ITC Adjustment								
60	Deferral	0	0	0	0	0	0	0	0
61	Restoration	0	0	0	0	0	0	0	0
62	Deferred Taxes	0	0	0	0	0	0	0	0
63	Current/Deferred Taxes True-up	(7,159)	0	0	0	0	0	0	(7,159)
64	Total Income Tax	(7,255)	0	0	(3,999)	11,616	7,777	(2,428)	5,712

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Docket UE-115, Order 01-777.

	Type I Adjustments	Normal Water-Plant Oprtn.	Normal Weather	Two-Cities	Gas Resale Revenues	Wage & Salary Adjustment	Incentive Pay
		(1)	(2)	(3)	(4)	(5)	(6)
	Operating Revenues						
1	Residential		11,766				
2	Commercial		(712)				
3	Industrial		(176)				
4	Other Revenue		(0)				
5	Unbilled Revenues		(1)				
5	Sales to Consumers	0	10,878	0	0	0	0
5a	Sales for Resale						
6	Other Operating Revenues				(13,254)		
7	Total Operating Revenues	0	10,878	0	(13,254)	0	0
	Operation & Maintenance						
8	Steam	754	0				
9	Nuclear	0	0				
10	Other	(14,657)	0				
11	Production	(13,903)	0	0	0	0	0
12	Purchased Power	(12,263)	4,765	0			
12a	RPA Exchange						
13	Sales for Resale	14,394	429				
14	Wheeling	1,325	0	(27)			
15	Net Variable Power Cost	(10,446)	5,194	(27)	0	0	0
16	Fixed Plant Cost						
17	Transmission						
18	Distribution						
19	Total Fixed O&M	0	0	0	0	0	0
20	Customer Accounts	0	54	0	0	0	0
21	Customer Service & Sales						
22	Administration & General	0	0	0	0	(1,414)	(1,896)
23	Other O&M	0	54	0	0	(1,414)	(1,896)
24	Total Operation & Maintenance	(10,446)	5,248	(27)	0	(1,414)	(1,896)
25	Depreciation & Amortization						
26	Taxes Other than Income	0	246	0	0	(350)	0
27	Income Taxes (Non-Federal)	696	357	(3)	(881)	118	127
28	Federal Income Tax Net of ITC	3,416	1,755	(15)	(4,327)	580	625
29	Deferred Income Taxes	0	0	31	0	0	0
30	Current/Deferred Taxes True-up						
31	ITC Adjustment	0	0	0	0	0	0
32	Total Oper. Expenses & Taxes	(6,334)	7,607	(14)	(5,209)	(1,065)	(1,144)
33	Utility Operating Income	6,334	3,271	14	(8,045)	1,065	1,144

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	Type I Adjustments	Normal Water-Plant Oprtn. (1)	Normal Weather (2)	Two-Cities (3)	Gas Resale Revenues (4)	Wage & Salary Adjustment (5)	Incentive Pay (6)
	Average Rate Base						
34	Utility Plant In Service					(328)	(409)
35	Acc Depeciation						
36	Acc Def. Income Taxes			54			
37	Acc Def. Inv. Tax Credit	0	0	0	0	0	0
38	Net Utility Plant	0	0	(54)	0	(328)	(409)
39	-----						
40	Net Trojan Investment						
41	Weatherization Investment						
42	Deferred Programs & Investments			(138)			
43	Operating Materials & Fuel						
44	Misc. Deferred Credits						
45	Unamortized Ratepayer Gains						
46	Working Cash	(283)	339	(1)	(232)	(47)	(51)
47	Total Average Rate Base	(283)	339	(193)	(232)	(376)	(460)
	Income Tax Calculations						
48	Book Revenues	0	10,878	0	(13,254)	0	0
49	Book Expenses	(10,446)	5,494	(27)	0	(1,763)	(1,896)
50	Not used						
51	Int. R-Base @ Wtd Cost Debt	(10)	12	(7)	(8)	(13)	(16)
52	Schedule M Differences			80	0		
53	State Taxable Income	10,456	5,372	(46)	(13,246)	1,777	1,912
54	State Tax 6.6547%	696	357	(3)	(881)	118	127
55	Additional Tax Depreciation						
56	Federal Taxable Income	9,760	5,015	(43)	(12,364)	1,658	1,785
57	Fed Tax @ 35%	3,416	1,755	(15)	(4,327)	580	625
58	ITC @ 0%	0	0	0	0	0	0
59	Current Federal Tax	3,416	1,755	(15)	(4,327)	580	625
	ITC Adjustment						
60	Deferral	0	0	0	0	0	0
61	Restoration						
62	Deferred Taxes	0	0	31	0	0	0
63	Current/Deferred Taxes True-up	0	0	0	0	0	0
64	Total Income Tax	4,112	2,113	13	(5,209)	699	752

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Docket UE-115, Order 01-777.

	Type 1 Adjustments	Marketing & Sales (7)	Advertising Category "A" & "C" (8)	Retail Unbundling (9)	Customer Accounts (10)	Prior Year Tax Adj. (11)	Blank (12)
	Operating Revenues						
1	Residential						
2	Commercial						
3	Industrial						
4	Other Revenue						
5	Unbilled Revenues						
5	Sales to Consumers	0	0	0	0	0	0
5a	Sales for Resale						
6	Other Operating Revenues						
7	Total Operating Revenues	0	0	0	0	0	0
	Operation & Maintenance						
8	Steam						
9	Nuclear						
10	Other						
11	Production	0	0	0	0	0	0
12	Purchased Power						0
12a	RPA Exchange						
13	Sales for Resale						
14	Wheeling						
15	Net Variable Power Cost	0	0	0	0	0	0
16	Fixed Plant Cost						
17	Transmission						
18	Distribution						
19	Total Fixed O&M	0	0	0	0	0	0
20	Customer Accounts	0	0	0	(1,411)	0	0
21	Customer Service & Sales	1,349	0		0		
22	Administration & General	0	0	(176)	0	0	0
23	Other O&M	1,349	0	(176)	(1,411)	0	0
24	Total Operation & Maintenance	1,349	0	(176)	(1,411)	0	0
25	Depreciation & Amortization						
26	Taxes Other than Income	0	0	0	0	0	0
27	Income Taxes (Non-Federal)	(90)	0	12	94	10	0
28	Federal Income Tax Net of ITC	(441)	0	58	461	48	0
29	Deferred Income Taxes	0	0	0	0	0	0
30	Current/Deferred Taxes True-up					1,189	
31	ITC Adjustment	0	0	0	0	0	0
32	Total Oper. Expenses & Taxes	818	0	(107)	(856)	1,247	0
33	Utility Operating Income	(818)	0	107	856	(1,247)	0

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	Type 1 Adjustments	Marketing & Sales	Advertising Category "A" & "C"	Retail Unbundling	Customer Accounts	Prior Year Tax Adj.	Blank
		(7)	(8)	(9)	(10)	(11)	(12)
	Average Rate Base						
34	Utility Plant In Service	0					
35	Accumulated Depeciation	0					
36	Acc. Def. Income Taxes					4,311	
37	Acc. Def. Inv. Tax Credit	0	0	0	0	0	0
38	Net Utility Plant	0	0	0	0	(4,311)	0
39	-----						
40	Net Trojan Investment						
41	Weatherization Investment						
42	Deferred Programs & Investments						
43	Operating Materials & Fuel						
44	Misc. Deferred Credits						
45	Unamortized Ratepayer Gains						
46	Working Cash	36	0	(5)	(38)	56	0
47	Total Average Rate Base	36	0	(5)	(38)	(4,255)	0
	Income Tax Calculations						
48	Book Revenues	0	0	0	0	0	0
49	Book Expenses	1,349	0	(176)	(1,411)	0	0
50	Not used						
51	Int. R-Base @ Wtd Cost Debt	1	0	(0)	(1)	(148)	0
52	Schedule M Differences	0	0	0	0	0	0
53	State Taxable Income	(1,350)	0	176	1,412	148	0
54	State Tax 6.6547%	(90)	0	12	94	10	0
55	Additional Tax Depreciation						
56	Federal Taxable Income	(1,260)	0	165	1,319	138	0
57	Fed Tax @ 35%	(441)	0	58	461	48	0
58	ITC @ 0%	0	0	0	0	0	0
59	Current Federal Tax	(441)	0	58	461	48	0
	ITC Adjustment						
60	Deferral	0	0	0	0	0	0
61	Restoration						
62	Deferred Taxes	0	0	0	0	0	0
63	Current/Deferred Taxes True-up	0	0	0	0	1,189	0
64	Total Income Tax	(531)	0	69	555	1,247	0

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	Type I Adjustments	SERP	MDCP	Blank	Total Type 1 Adjustments
		(13)	(14)	(15)	(16)
	Operating Revenues				
1	Residential				11,766
2	Commercial				(712)
3	Industrial				(176)
4	Other Revenue				(0)
5	Unbilled Revenues				(1)
5	Sales to Consumers	0	0	0	10,878
5a	Sales for Resale				
6	Other Operating Revenues				(13,254)
7	Total Operating Revenues	0	0	0	(2,376)
	Operation & Maintenance				
8	Steam				754
9	Nuclear				0
10	Other				(14,657)
11	Production	0	0	0	(13,903)
12	Purchased Power				(7,498)
12a	RPA Exchange				0
13	Sales for Resale				14,823
14	Wheeling				1,298
15	Net Variable Power Cost	0	0	0	(5,279)
16	Fixed Plant Cost			0	0
17	Transmission				0
18	Distribution				0
19	Total Fixed O&M	0	0	0	0
20	Customer Accounts	0	0	0	(1,357)
21	Customer Service & Sales				1,349
22	Administration & General	(1,552)	(4,512)	0	(9,551)
23	Other O&M	(1,552)	(4,512)	0	(9,559)
24	Total Operation & Maintenance	(1,552)	(4,512)	0	(14,838)
25	Depreciation & Amortization				0
26	Taxes Other than Income	0	0	0	(104)
27	Income Taxes (Non-Federal)	105	301	0	718
28	Federal Income Tax Net of ITC	513	1,476	0	3,524
29	Deferred Income Taxes	0	0	0	31
30	Current/Deferred Taxes True-up				1,189
31	ITC Adjustment	0	0	0	0
32	Total Oper. Expenses & Taxes	(934)	(2,736)	0	(9,479)
33	Utility Operating Income	934	2,736	0	7,103

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	Type I Adjustments	SERP	MDCP	Blank	Total Type 1 Adjustments
		(13)	(14)	(15)	(16)
	Average Rate Base				
34	Utility Plant In Service				(737)
35	Accumulated Depeciation				0
36	Acc Def. Income Taxes				4,365
37	Acc Def. Inv. Tax Credit	0	0	0	0
38	Net Utility Plant	0	0	0	(5,102)
39	-----				0
40	Net Trojan Investment				0
41	Weatherization Investment				0
42	Deferred Programs & Investments				(138)
43	Operating Materials & Fuel				0
44	Misc. Deferred Credits	(520)			(520)
45	Unamortized Ratepayer Gains				0
46	Working Cash @ 4.55%	(42)	(122)	0	(338)
47	Total Average Rate Base	(562)	(122)	0	(6,099)
	Income Tax Calculations				
48	Book Revenues	0	0	0	(2,376)
49	Book Expenses	(1,552)	(4,512)	0	(14,942)
50	Not used				0
51	Int. R-Base @ Wtd Cost Debt	(20)	(4)	0	(198)
52	Schedule M Differences	0	0	0	80
53	State Taxable Income	1,572	4,517	0	10,787
54	State Tax 6.6547%	105	301	0	718
55	Additional Tax Depreciation	0	0	0	0
56	Federal Taxable Income	1,467	4,216	0	10,070
57	Fed Tax @ 35%	513	1,476	0	3,524
58	ITC @ 0%	0	0	0	0
59	Current Federal Tax	513	1,476	0	3,524
	ITC Adjustment				
60	Deferral	0	0	0	0
61	Restoration	0	0	0	0
					0
62	Deferred Taxes	0	0	0	31
63	Current/Deferred Taxes True-up	0	0	0	1,189
64	Total Income Tax	618	1,776	0	5,463

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	Type II Adjustments	Escalation and Period-End Rate Base	Blank	End-of-Period Anualizing Adjustment	Blank	Total
		(1)	(2)	(3)	(4)	(5)
1	Residential			3,273		3,273
2	Commercial			1,034		1,034
3	Industrial					0
4	Other Revenue					0
5	Unbilled Revenues					0
5	Sales to Consumers	0	0	4,307	0	4,307
5a	Sales for Resale					
6	Other Operating Revenues					0
7	Total Operating Revenues	0	0	4,307	0	4,307
	Operation & Maintenance					
8	Steam					0
9	Nuclear					0
10	Other					0
11	Production	0	0	0	0	0
12	Purchased Power			2,365		2,365
12a	RPA Exchange					0
13	Sales for Resale					0
14	Wheeling					0
15	Net Variable Power Cost	0	0	2,365	0	2,365
16	Fixed Plant Cost	754				754
17	Transmission	62				62
18	Distribution	521		834		1,355
19	Total Fixed O&M	1,337	0	834	0	2,171
20	Customer Accounts/Bad Debt	543	0	22	0	564
21	Customer Service & Sales	113				113
22	Admin. & General / OPUC Fee	1,025	0	0	0	1,025
23	Other O&M	1,681	0	22	0	1,702
24	Total Operation & Maintenance	3,017	0	3,220	0	6,238
25	Depreciation & Amortization			1,147		1,147
26	Other Taxes/Franchise Fee	0	0	509	0	509
27	Income Taxes (Non-Federal)	(227)	0	(38)	0	(265)
28	Federal Inc. Tax Net of ITC	(1,114)	0	(188)	0	(1,302)
29	Deferred Income Taxes	0	0	0	0	0
30	Current/Deferred Taxes True-up					0
31	ITC Adjustment	0	0	0	0	0
32	Total Oper. Exp & Taxes	1,677	0	4,650	0	6,327
33	Utility Operating Income	(1,677)	0	(343)	0	(2,020)

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		Escalation and Period-End Rate Base	Blank	End-of-Period Anualizing Adjustment	Blank	Total
		(1)	(2)	(3)	(4)	(5)
	Average Rate Base					
34	Utility Plant In Service	57,660				57,660
35	Accumulated Depeciation	45,610				45,610
36	Acc Def. Income Taxes	222				222
37	Acc Def. Inv. Tax Credit	(2,115)				(2,115)
38	Net Utility Plant	13,944	0	0	0	13,944
39	-----					
40	Net Trojan Investment	0				0
41	Weatherization Investment	(192)				(192)
42	Deferred Programs & Investments	267				267
43	Operating Materials & Fuel	682				682
44	Misc. Deferred Credits	(2,549)				(2,549)
45	Unamortized Ratepayer Gains	0				0
46	Working Cash 4.46%	75	0	207	0	282
47	Total Average Rate Base	12,227	0	207	0	12,434
	Income Tax Calculations					
48	Book Revenues	0	0	4,307	0	4,307
49	Book Expenses	3,017	0	4,877	0	7,894
50	Reverse Env. Tax for Calculation	0	0	0	0	0
51	Int. R-Base @ Wtd Cost of Debt	392	0	7	0	398
52	Schedule M Differences	0	0	0	0	0
53	State Taxable Income	(3,409)	0	(576)	0	(3,985)
54	State Tax 6.6547%	(227)	0	(38)	0	(265)
54a	Pollution Control Tax Credit					
55	Net State Taxes					
56	Federal Taxable Income	(3,182)	0	(538)	0	(3,720)
57	Fed Tax 35%	(1,114)	0	(188)	0	(1,302)
58	ITC @ 0%	0	0	0	0	0
59	Current Federal Tax	(1,114)	0	(188)	0	(1,302)
	ITC Adjustment					
60	Deferral	0	0	0	0	0
61	Restoration	0	0	0	0	0
62	Deferred Taxes	0	0	0	0	0
63	Current/Deferred Taxes True-up	0	0	0	0	0
64	Total Income Tax	(1,341)	0	(226)	0	(1,567)

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COMPOSITE COST OF CAPITAL

Order 01-777, UE 115	Average Outstanding	2003 Percent of Capital	2003 Percent Cost	2003 Weighted Percent Cost
Long Term Debt	887,900	46.32%	7.51%	3.48%
Preferred Stock	29,250	1.53%	8.43%	0.13%
Common Equity	999,781	52.16%	10.50%	5.48%
Total	1,916,931	100.00%		9.08%

	Actual Averages	Average Outstanding	Percent of Capital	Percent Cost	Weighted Percent Cost
(A)	Long Term Debt	978,110	43.31%	8.03%	3.48%
(A)	Preferred Stock	25,089	1.11%	8.43%	0.09%
(A)	Common Equity	1,255,244	55.58%	6.92%	3.84%
	Total	2,258,444	100.00%		7.41%

	Actual End of Period	End of Period Outstanding	Percent of Capital	Percent Cost	Weighted Percent Cost
(E)	Long Term Debt	931,250	43.50%	7.36%	3.20%
(E)	Preferred Stock	23,473	1.10%	8.43%	0.09%
(E)	Common Equity	1,185,972	55.40%	7.90%	4.38%
	Total	2,140,695	100.00%		7.67%

Note: End of period capital structure and costs used for Pro Forma ROR and ROE calcs.

Order 91-186 Methodology

Interest Adjustment (Utility Tax Adjustment)	
Rate Base	1,768,613
Wtd Cost of Debt	3.48%
Int. for tax deduction	61,479
Int. for tax calculation	81,269
Utility tax adjust.	(19,789)

*From F&O rpt. Long-term debt, short-term debt&other(no AFDC)

	Common Equity		Common Equity
Dec '02	1,129,429	Jul '03	1,163,466
Jan '03	1,142,010	Aug '03	1,166,646
Feb '03	1,150,237	Sep '03	1,157,901
Mar '03	1,149,444	Oct '03	1,164,014
Apr '03	1,155,862	Nov '03	1,170,766
May '03	1,165,027	Dec '03	1,185,972
Jun '03	1,162,159		

(A) Thirteen month average.
(E) End of Period
From F&O report. Common Equity + ESOP

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CORPORATE ALLOCATIONS

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CORPORATE ALLOCATIONS

I. INTRODUCTION and SUMMARY

Q. Please state your names and positions with Enron Corp. (Enron) and Portland General Electric (PGE).

A. My name is Mark Lindsey. I am Vice President and Assistant Controller of Enron Corp. My current responsibilities include Financial Planning and Reporting, as well as the Corporate Accounting functions of Enron.

My name is James J. Piro. I am Vice President of Business Development for PGE. My current responsibilities at PGE include providing planning support to the senior management team, reviewing and providing input on business opportunities for PGE, providing leadership and guidance on business transactions contemplated by PGE, and coordinating PGE's efforts on the valuation of PGE's supply portfolio and associated transition costs. I am also sponsoring PGE Exhibit 1700, Competitive Transition Mechanism.

Our qualifications appear at the end of the testimony.

Q. What is the purpose of your joint testimony?

A. The purpose of our testimony is to present and explain 2002 test year Enron allocations to PGE of $10.6 million and direct charges of $31.5 million, for a total of $42.1 million. As explained in PGE Exhibit 200, Revenue Requirement, we developed the 2002 test year assuming that PGE remains an Enron subsidiary.

Q. How do these costs compare to Enron's charges to PGE in prior years?

A. The tables below show the major categories of costs Enron allocates and charges directly to PGE, comparing 1999 actual costs and the 2002 test year forecast, with cross references to testimony further detailing costs described in this testimony.

Table 1 – Enron Direct Charges for Services

Enron Service	1999 Actual	2002 Test Year	Testimony Cross Reference
HR Services	$5,384,484	$25,519,911	Exhibit 900, Compensation
IT Services	$3,054,939	$3,575,116	Exhibit 800, IT
Legal Services	$204,865	$67,043	
Risk Mgmt. Services	$113,916	$364,407	
Actg./Tax Services	$945,863	$1,058,028	
Misc. Services	$1,248,227	$908,852	
Total Direct Charges	$10,952,294	$31,493,357	

Table 2 – Enron MMF Allocations for Services

Enron Service	1999 Actual	2002 Test Year	Testimony Cross Reference
HR Services	$3,606,338	$3,056,757	Exhibit 900, Compensation
Corporate Communications	$567,270	$587,677	
Investor Relations	$454,014	$1,306,297	
Finance & Actg.	$1,856,008	$3,039,996	
Executive Services	$3,208,304	$1,402,672	
Misc. Services	$0	$540,537	
Legal/Regulatory	$1,341,252	$702,907	
Total MMF Allocations	$11,033,226	$10,636,843	

As shown in Table 1, Enron's direct charges to PGE have increased from 1999 to 2002 by $20.5 million. As shown in Table 2, Enron's allocations to PGE through the MMF decreased from 1999 to the 2002 test year by $0.40 million. PGE Exhibit 602 shows these costs in greater detail.

Q. Why have Enron's direct charges to PGE increased from 1999 to the 2002 test year?

The primary reason for the increase in direct charges from 1999 to 2002 is the transfer of certain benefit programs from PGE to Enron. Enron charges for these benefit programs total $15.6 million in 2002 compared to $0 in 1999 because PGE administered the programs in 1999. As discussed below, the direct charges for benefit programs are $1.5 million less than PGE would have incurred to obtain the same level of service. The additional $4.9 million increase in direct charges between 1999 and 2002 is the result of Enron increasing services to PGE in the areas of information technology, human resources and risk management.

II. ENRON ALLOCATION and DIRECT CHARGE METHOLDOLOGY

Q. Please describe how Enron directly charges to PGE and other Enron subsidiaries.

A. Enron directly charges corporate costs based on the method most appropriate for the type of service being provided. The preference is for charging costs based on direct measures of use whenever possible, such as use of labor or use of resources. PGE Exhibit 603 summarizes Enron's direct charging methods by service type.

Q. What costs does Enron allocate to PGE and what allocation method does it use?

A. Enron allocates costs for which none of the direct charge methods work. It uses the Modified Massachusetts Formula (MMF), a common allocation methodology. The MMF is a three-factor model. The three-factor average determines the MMF factor for the particular subsidiary. The product of the MMF factor and the sum of all costs that cannot be directly charged equals the cost allocated via the MMF method.

Q. How is the MMF factor calculated?

A. The MMF factor is an equal weighting of three factors: payroll costs, gross plant, and gross margin. For example, if subsidiary X represents 10% of payroll costs, 12% of gross plant, and 14% of gross margins for the corporate entity, the MMF factor for subsidiary X is the average of those three factors, or 12%. As a result, the MMF method allocates to subsidiary X 12% of total corporate costs that Enron cannot otherwise assign or allocate. For the 2002 test period, PGE's MMF factor is 19.0%, based on the 12-month period ending 12/31/98 for PGE's share of Gross Margin and Payroll and 9/30/99 for Gross

Plant. We provide the calculation of PGE's MMF factor in the work papers, along with the MMF factors for Enron's other regulated subsidiaries.

Q. Why is it reasonable to use the MMF method for allocating corporate costs?

A. The MMF method is a simple and rational way to allocate costs on a non-discriminatory basis. By using three factors, the MMF greatly reduces the potential bias inherent in using a single factor. A company the size and diversity of Enron needs a method for allocating corporate costs across the subsidiaries that benefit from the services provided at the corporate level.

Q. Have any regulatory agencies approved the MMF method for use by Enron subsidiaries?

A. Yes. Enron subsidiaries use this method in their cost of service proceedings before the Federal Energy Regulatory Commission (FERC). The FERC has accepted the MMF method for allocating Enron's corporate costs to its regulated subsidiaries, which include: Transwestern Pipeline Company, Florida Gas Transmission Company, Northern Plains Gas Company, and Northern Natural Gas Company.

Q. What criteria does PGE use for including the Enron allocations and direct charges in your revenue requirement?

A. An Enron cost must meet the following criteria for inclusion in rates:

1. It must be a necessary, just, and reasonable regulated utility expense;
2. It must be for functions that PGE would perform as a stand-alone utility;
3. It must not arise from non-regulated activities; and

4. It must not duplicate functions that already exist at PGE.

These criteria appear in the October 31, 1996, PGE/Affiliates Master Service Agreement, approved by the Commission in Order 97-497. They are also in the Revised PGE/Affiliates Master Service Agreement filed on March 28, 2000 (OPUC Docket UI-181).

Q. **Please generally describe Enron's 2000 corporate budgeting process.**

A. First, Enron develops budgets for each corporate Cost Center (CC). Total 2000 budgeted corporate costs are $810.4 million. Next, Enron analyzes the CC budgets to identify the costs directly attributable to subsidiaries, including PGE, which total $579.1 million in 2000. Enron then uses the MMF method to allocate a pool of costs that support its subsidiaries but cannot be directly charged to subsidiaries. The pool of costs allocated through the MMF method total $59.5 million in 2002. Costs that are not directly charged or allocated to subsidiaries based on the MMF method are retained at the corporate level. For 2002, Enron did not directly charge or allocate to subsidiaries $171.9 million.

Q. **What process did PGE use to estimate 2002 test year Enron allocations and direct charges?**

A. First, PGE adjusted the 2000 budget of Enron direct charges to reflect PGE calculations of expected direct charges for certain benefits programs. PGE Exhibit 604 shows this adjustment. In total, PGE estimates that the 2000 Enron direct charges will be $161,460 lower than the 2000 Enron budget figures. Next, we escalated the adjusted 2000 budget for two years of expected inflation in direct charges and allocations. Third, we removed certain allocations from the 2002 budget total to reflect traditional regulatory disallowance of these services or to reflect the failure of the services to meet the criteria discussed above. PGE Exhibit 604, column 8, shows what we removed. Column 9 of PGE Exhibit 604 shows our 2002 test year forecast of $42.1 million.

III. COMPARISON of DIRECT CHARGES

Q. How do the total Enron direct charges for the test period compare to historical Enron direct charges?

A. Enron direct charges have changed substantially from 1998 to 2002. The change in direct charges is primarily the result of two factors. First, beginning in 2000, Enron charges PGE for the Medical/Dental Insurance program, Life Insurance/ Accidental Death & Dismemberment Insurance and Long-Term Disability Insurance programs, as well as the 401K-matching program (called the Retirement Savings Program). Previously, PGE incurred these costs directly.

Second, Enron began charging PGE for SAP-related costs in 1999. The SAP system is an integrated management information system that provides compatibility of data within corporate functions and across corporate entities.

Of the $23.6 million increase in Enron direct charges from 1998 to the 2002 test period, $15.6 million relate to direct charges for benefits programs and $3.0 million relate to SAP. The remaining increase of $5.0 million is the result of a large number of new services Enron is providing PGE at our request, including risk management, human resources, and information technology services.

Q. Is it reasonable for PGE to recover test year charges for the benefit programs described above?

A. Yes. The benefit programs that Enron now directly charges to PGE are long-standing benefit programs necessary to attract and retain skilled employees and maintain the physical health of PGE's employee base. Absent the merger with Enron, PGE would have continued to provide similar benefit programs to our employees.

Table 3 below summarizes the 2002 Enron charges for benefit programs and PGE's estimate of the cost to provide these programs internally:

Table 3

Benefit Program	Charge from Enron in 2002	Expected cost at PGE
Medical/Dental Insurance	8,758,288	9,111,672
Life and AD&D Insurance	805,356	1,001,000
Long-Term Disability	503,356	1,462,000
Retirement Savings Plan	5,516,000	5,516,000
Total Charges/Costs	15,582,900	17,096,672

Enron's total charge for benefit programs is lower than PGE's expected cost of these programs because Enron's flexible spending plan (flex plan) limits the cost of these programs (except Retirement Savings Program) to $5,200 per employee. The cost of coverage beyond $5,200 is the employee's responsibility. PGE did not have a similar plan and did not expect to develop a flex plan before the merger. As the cost of these programs, particularly Medical/Dental, increases over time, the benefit of Enron's flex program will grow. The cost of the Retirement Savings Program is the same whether charged by Enron or incurred internally at PGE. PGE Exhibit 900, Compensation, more fully describes benefits programs, including comparison with prior years' levels.

Q. Has Enron directly charged PGE for costs associated with the implementation of SAP?

A. Yes. Charges in the test year are approximately $3.0 million. PGE Exhibit 800, Information Technology, contains a detailed discussion of PGE's 2002 test year information technology costs.

IV. QUALIFICATIONS

Q. Mr. Piro, please describe your educational background and experience.

A. I received a Bachelor of Science degree from Oregon State University in Civil Engineering in 1974 with an emphasis in Structural Engineering. In addition, I have taken graduate courses in engineering, accounting, economics, and rate making. I am a registered Professional Engineer in Civil Engineering in the State of California (Registration No. 28174). I joined Portland General Electric in 1980 and have held various positions in Generation Engineering, Economic Regulation, Financial Analysis and Forecasting, Power Contracts, Economic Analysis, and Planning Support, Analysis and Forecasting. I entered my current position as Vice President of Business Development in 1998.

Q. Mr. Lindsey, please describe your educational background and experience.

A. I received a Bachelors Degree in Professional Accounting from Mississippi State University. I am a Certified Public Accountant (C.P.A.) in the State of Texas. Since joining Enron, I have held various positions including Controller of Enron Energy Services, Senior Director of Enron Capital and Trade, and Controller of Enron's Liquids businesses. Prior to joining Enron, I held positions as Controller for SLT Communications, Inc. and Senior Manager with Arthur Andersen & Co. in Houston. I have held my current position of Vice President and Assistant Controller for Enron Corp. since 1998.

LIST of EXHIBITS

PGE Exhibit 602	1998 – 2002 Enron Allocations and Direct Charges
PGE Exhibit 603	Allocation Method by Service Type
PGE Exhibit 604	Development of Test Year Allocations / Direct Charges

1998 - 2002 Enron Allocations & Direct Charges Summary

Description	SAP CC Number	1998 PGE Actuals	1999 PGE Actuals	2000 PGE Budget	2001 PGE Budget	2002 PGE Budget	2002 PGE Test Year
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
MMF Allocations:							
Direct Cost In - Shared Services		3,848,371	-	-	-	-	-
Direct Cost In - Other		257,221	-	-	-	-	-
HUMAN RESOURCES:							
Benefits & Compensation	100001	-	-	72,000	73,656	75,424	75,424
Long Term Incentive	100007	-	319,137	259,000	264,957	271,316	271,316
Drug/Alcohol Testing	100008	-	-	5,000	5,115	5,238	5,238
HR Support Services	100013	-	-	40,000	40,920	41,902	41,902
Workforce Diversity	100022	71,714	-	98,000	100,254	102,660	102,660
HRIS	100033	-	-	116,000	118,668	121,516	121,516
VP - HR Administration	100050	94,881	-	46,000	47,058	48,187	48,187
HR & Community Relations- Executive	100218	-	-	104,000	106,392	108,945	108,945
Fair Employment Practices	100110	-	-	27,000	27,621	28,284	28,284
All Employee Stock Option Plan	100118	-	282,942	-	-	-	-
NQ Stock Plan	100113	2,014	189,689	-	-	-	-
Restricted Stock	100112	-	78,210	-	-	-	-
Annual Incentive	100114	-	2,332,440	1,723,000	1,762,629	1,804,932	1,804,932
Exec Perqs	100115	10,878	41,580	40,000	40,920	41,902	-
VP- Compensation & Benefits		-	108,108	-	-	-	-
Supplier Diversity Program		58,822	-	-	-	-	-
Decision Technology		-	15,840	-	-	-	-
Employee Performance Awards	100116	31,224	-	41,000	41,943	42,950	42,950
Corporate Memberships	100134	-	108,900	-	-	-	-
Staffing	100058	122,882	-	251,000	256,773	262,936	262,936
Labor Relations Risk Management	100092	-	-	14,000	14,322	14,666	14,666
Vision & Values Task Force	100230	-	-	25,000	25,575	26,189	26,189
Corp Organization Effectiveness Executive		-	79,992	-	-	-	-
Organization Planning & Performance	100077	-	49,500	97,000	99,231	101,613	101,613
Corp. Recruiting		119,256	-	-	-	-	-
Total - HR		511,671	3,606,338	2,958,000	3,026,034	3,098,659	3,056,757
CORPORATE COMMUNICATIONS:							
Sr. Vice President - Corp Mkt & Res		128,925	-	-	-	-	-
Corporate Communications		105,759	143,550	-	-	-	-
Corporate Memberships	100134	-	-	95,000	97,185	99,517	99,517
Matching Gifts	100138	-	-	123,000	125,829	128,849	-
Community Relations	100019	-	-	409,000	418,407	428,449	428,449
Community Relations Programs	100056	-	-	57,000	58,311	59,710	59,710
Community Relations- Employee Events	100070	-	-	23,000	23,529	24,094	-
Media Relations		522,146	423,720	-	-	-	-
Total - Corp Comm		756,830	567,270	707,000	723,261	740,619	587,677
INVESTOR RELATIONS:							
Sr VP- Corp Marketing & Res.		-	100,980	-	-	-	-
Investor Relations	100024	289,477	353,034	439,000	449,097	459,875	459,875
Public Relations- Annual Report	100136	-	-	147,000	150,381	153,990	153,990
Public Relations- Corporate Communications	100137	-	-	336,000	343,728	351,977	351,977
Public Relations- Employee Communications	100135	-	-	8,000	8,184	8,380	8,380
Executive Board Meeting Expenses	100140	252,411	-	317,000	324,291	332,074	332,074
- Total - Investor Relations		541,888	454,014	1,247,000	1,275,681	1,306,297	1,306,297

1998 - 2002 Enron Allocations & Direct Charges Summary

Description	SAP CC Number (1)	1998 PGE Actuals (2)	1999 PGE Actuals (3)	2000 PGE Budget (4)	2001 PGE Budget (5)	2002 PGE Budget (6)	2002 PGE Test Year (7)
FINANCE & ACCOUNTING:							
Sr. Vice President - CAO	100016	155,314	178,596	156,000	159,588	163,418	163,418
Accounts Payable- Executive	100801	-	-	12,000	12,276	12,571	12,571
Vice President - Tax	100027	622,466	884,862	748,000	765,204	783,569	783,569
Ad Valorem Tax	100029	-	21,978	44,000	45,012	46,092	46,092
State Tax Group	100026	-	-	5,000	5,115	5,238	5,238
Tax- Analyst/Intern Recruiting	100045	-	-	97,000	99,231	101,613	101,613
Internet Content Manager		-	29,700	-	-	-	-
RAC- Global Credit Group	100052	-	-	36,000	36,828	37,712	37,712
IT - Technology Training	100103	-	-	21,000	21,483	21,999	21,999
SAP Costs Related to Project Apollo		-	-	494,000	505,362	517,491	517,491
SAP COE Control Group	100216	-	-	326,000	333,498	341,502	341,502
Accounts Payable- MSA/SAP	100220	-	-	78,000	79,794	81,709	81,709
Other G&A Costs		-	71,632	-	-	-	-
Sales & Use Tax	100280	-	-	4,000	4,092	4,190	4,190
Professional Accounting Fees	100127	-	-	305,000	312,015	319,503	319,503
Corporate Financial Planning		200,035	-	-	-	-	-
Corporate Accounting & Reporting	100012	393,422	669,240	576,000	589,248	603,390	603,390
Total - Finance & Accounting		1,371,237	1,856,008	2,902,000	2,968,746	3,039,996	3,039,996
LEGAL & REGULATORY:							
Corporate Secretary	100030	445,395	-	482,000	493,086	504,920	504,920
Corporate Legal	100040	265,303	207,702	162,000	165,726	169,703	169,703
Environmental Legal	100041	-	-	5,000	5,115	5,238	5,238
Legal Library	100139	-	-	22,000	22,506	23,046	23,046
Sr VP - Environmental & International		99,272	-	-	-	-	-
American Indian Affairs- Govt Affairs	100105	-	219,978	1,000	1,023	1,048	-
Env. & Intnl. Govt. Affairs		-	103,554	-	-	-	-
Federal Government Affairs	100042	325,213	810,018	498,000	509,454	521,681	-
State Government Affairs		209,100	-	-	-	-	-
Total - Legal & Regulatory		1,344,284	1,341,252	1,170,000	1,196,910	1,225,636	702,907
MISCELLANEOUS:							
Health Center	100034	-	-	32,000	32,736	33,522	-
Vacant Space	100064	-	-	68,000	69,564	71,234	71,234
Houston Children's Chorus	100065	-	-	9,000	9,207	9,428	-
United Way Campaign	100069	-	-	90,000	92,070	94,280	-
Best Buddies	100076	-	-	2,000	2,046	2,095	-
Wind Down- Omaha	100109	-	-	2,000	2,046	2,095	-
Teach for America	100132	-	-	10,000	10,230	10,476	-
Support Services (Co 423 Charges)	100211	-	-	25,000	25,575	26,189	26,189
Insurance Preimiums	100255	-	-	423,000	432,729	443,114	443,114
Work Life	100805	-	-	34,000	34,782	35,617	-
Total - Miscellaneous		-	-	695,000	710,985	728,049	540,537
EXECUTIVE SERVICES:							
Executive Consultants		48,145	-	-	-	-	-
President and COO		284,239	299,772	-	-	-	-
Corporate Secretary		-	514,998	-	-	-	-
Executive Reception	100020	88,434	138,204	95,000	97,185	99,517	99,517
Management Conference	100066	-	9,504	28,000	28,644	29,331	29,331
Corporate Memberships		70,506	-	-	-	-	-
Chairman and CEO	100044	448,216	538,956	563,000	575,949	589,772	589,772
Corporate Aircraft Usage (1)	100207	922,820	898,524	282,000	288,486	295,410	-
Chief of Staff		149,875	-	-	-	-	-
Vice Chairman (Sutton)	100281	-	-	434,000	443,982	454,638	454,638
Community Affairs		247,979	114,396	-	-	-	-
Executive Board Meeting Exp		-	299,970	-	-	-	-
New Building		-	94,446	-	-	-	-
Corporate Development		20,145	-	-	-	-	-
Corp Billing RC (EOC/MSA & ECM)	100081	-	299,574	219,000	224,037	229,414	229,414
Total - Executive Services		2,280,359	3,208,344	1,621,000	1,658,283	1,698,082	1,402,672
Sub-Total of MMF method		10,911,860	11,033,226	11,300,000	11,559,900	11,837,338	10,636,843

1998 - 2002 Enron Allocations & Direct Charges Summary

Description	SAP CC Number	1998 PGE Actuals	1999 PGE Actuals	2000 PGE Budget	2001 PGE Budget	2002 PGE Budget	2002 PGE Test Year
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Direct Charges:							
Benefits & Compensation- Q	100001	390,286	324,996	952,000	973,896	997,270	997,270
Long Term Incentive- PGE	100007	177,732	164,037	191,000	195,393	200,082	200,082
IT- Corporate Executive	100010	-	354,939	22,000	22,506	23,046	23,046
HR Support Services	100013	-	200,004	447,000	457,281	468,256	468,256
State Tax Group	100026	-	45,863	50,000	51,150	52,378	52,378
Corporate Secretary	100030	-	12,588	13,000	13,299	13,618	13,618
HRIS	100033	-	-	150,000	153,450	157,133	157,133
Intellectual Capital	100035	-	27,000	16,000	16,368	16,761	16,761
Risk Mgmt- Research Group	100038	-	-	20,000	20,460	20,951	20,951
Corporate Legal	100040	-	192,277	-	-	-	-
Enrvironmental Legal	100041	-	-	51,000	52,173	53,425	53,425
VP- HR Administration	100050	-	-	398,000	407,154	416,925	416,925
IT Information Services	100051	-	-	11,139	11,395	11,669	11,669
RAC- Global Credit Group	100052	-	-	27,000	27,621	28,284	28,284
RAC- Due Dilligence	100053	-	-	58,000	59,334	60,758	60,758
RAC- Risk Analytics	100054	-	-	184,000	188,232	192,750	192,750
Staffing	100058	-	15,300	-	-	-	-
Management Conference	100066	-	-	18,000	18,414	18,856	18,856
RAC- Risk Mgmt Control	100068	-	-	35,000	35,805	36,664	36,664
Savings Plan (billed on actuals)	100083	-	-	4,738,171	5,305,000	5,516,000	5,516,000
Labor Relations Risk Management	100092	-	94,920	-	-	-	-
Fair Employment and Practices	100110	-	-	94,000	96,162	98,470	98,470
Restricted Stock	100112	-	57,822	750,000	767,250	785,664	785,664
NQ Stock Plan	100113	-	95,707	461,200	471,808	483,131	483,131
All Employee Stock Option Program	100118	4,231,949	4,301,618	4,087,000	5,731,000	5,952,000	5,952,000
EE Life, AD&D	100120	-	-	634,000	781,595	805,356	805,356
Long Term Disability	100121	-	-	396,000	488,506	503,356	503,356
Active Medical/Dental	100124	-	-	6,890,000	8,499,899	8,758,288	8,758,288
Flex Admin/BTA	100125	-	-	181,482	185,656	190,112	190,112
Professional Accounting Fees	100127	675,602	900,000	960,000	982,080	1,005,650	1,005,650
ASO Charges	100128	-	-	179,340	183,465	187,868	187,868
Employee Communications	100135	-	83,208	78,000	79,794	81,709	81,709
SAP COE Control Group	100216	-	-	1,500,000	1,534,500	1,571,328	1,571,328
EARN Risk Management	100225	-	-	26,000	24,000	25,000	25,000
IT Communications & Market Data	100242	-	-	242,000	247,566	253,508	253,508
IT Infrastructure & Integration	100243	-	-	112,000	114,576	117,326	117,326
IT Corporate Applications Development	100244	-	-	129,000	131,967	135,134	135,134
ECM - Insurance Premiums	100255	-	568,862	679,518	754,265	791,526	791,526
Drug Control		-	-	-	-	-	-
Telecomm/Data Comm Ops		-	-	-	-	-	-
Computer Services		-	-	-	-	-	-
Aviation- Direct		-	326,852	-	-	-	-
Benefits & Compensation- W		390,286	225,000	-	-	-	-
SAP Costs- Project Apollo		-	2,700,000	1,396,690	1,428,814	1,463,105	1,463,105
EPSC		-	17,965	-	-	-	-
ECM (MMF)		-	224,340	-	-	-	-
Risk Management		-	18,996	-	-	-	-
Payroll Taxes		246,756		-	-	-	-
Rent		1,746,022		-	-	-	-
Sub-Total of Direct Charges		7,858,633	10,952,294	26,177,540	30,511,834	31,493,357	31,493,357
Grand Total		18,770,493	21,985,520	37,477,540	42,071,734	43,330,694	42,130,200
Remove Aviation Charges in 1999[1]		-	(326,852)	-	-	-	-
Adjusted Grand Total		18,770,493	21,658,668	37,477,540	42,071,734	43,330,694	42,130,200

1: Aviation Charge in 1999 reversed in January 2000

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Allocation / Direct Charge Methods by Service Type

Service Type	Allocation Method	SAP CC Number
Via MMF		
HUMAN RESOURCES:		
Benefits & Compensation	MMF	100001
Long Term Incentive	MMF	100007
Drug/Alcohol Testing	MMF	100008
HR Support Services	MMF	100013
Workforce Diversity	MMF	100022
HRIS	MMF	100033
Sr. VP - ODT, FEP & Labor Relations	MMF	100050
HR & Community Relations- Executive	MMF	100218
Fair Employment Practices	MMF	100110
All Employee Stock Option Plan	MMF	100118
NQ Stock Plan	MMF	100113
Restricted Stock	MMF	100112
Annual Incentive	MMF	100114
Exec Perqs	MMF	100115
Employee Performance Awards	MMF	100116
Staffing	MMF	100058
Labor Relations Risk Management	MMF	100092
Vision & Values Task Force	MMF	100230
Organization Planning & Performance	MMF	100077
CORPORATE COMMUNICATIONS:		
Corporate Memberships	MMF	100134
Matching Gifts	MMF	100138
Community Relations	MMF	100019
Community Relations Programs	MMF	100056
Community Relations- Employee Events	MMF	100070
INVESTOR RELATIONS:		
Investor Relations	MMF	100024
Public Relations- Annual Report	MMF	100136
Public Relations- Corporate Communications	MMF	100137
Public Relations- Employee Communications	MMF	100135
Executive Board Meeting Expenses	MMF	100140
FINANCE & ACCOUNTING:		
Sr. Vice President - CIAO	MMF	100016
Accounts Payable- Executive	MMF	100801
Vice President - Tax	MMF	100027
Ad Valorem Tax	MMF	100029
State Tax Group	MMF	100026
Tax- Analyst/Intern Recruiting	MMF	100045
RAC- Global Credit Group	MMF	100052
IT - Technology Training	MMF	100103
SAP Costs Related to Project Apollo	MMF	
SAP COE Control Group	MMF	100216
Accounts Payable- MSA/SAP	MMF	100220
Sales & Use Tax	MMF	100280
Professional Accounting Fees	MMF	100127
Corporate Accounting & Reporting	MMF	100012
LEGAL & REGULATORY:		
Corporate Secretary	MMF	100030
Corporate Legal	MMF	100040
Environmental Legal	MMF	100041
Legal Library	MMF	100139
American Indian Affairs- Govt Affairs	MMF	100105
Federal Government Affairs	MMF	100042

Allocation / Direct Charge Methods by Service Type

Service Type	Allocation Method	SAP CC Number
MISCELLANEOUS:		
Health Center	MMF	100034
Vacant Space	MMF	100064
Houston Children's Chorus	MMF	100065
United Way Campaign	MMF	100069
Best Buddies	MMF	100076
Wind Down- Omaha	MMF	100109
Teach for America	MMF	100132
Support Services (Co 423 Charges)	MMF	100211
Insurance Preimiums	MMF	100255
Work Life	MMF	100805
EXECUTIVE SERVICES:		
Executive Reception	MMF	100020
Management Conference	MMF	100066
Chairman and CEO	MMF	100044
Corporate Aircraft Usage (1)	MMF	100207
Vice Chairman (Sutton)	MMF	100281
Corp Billing RC (EOC/MSA & ECM)	MMF	100081
Via Direct Charges:		
Benefits & Compensation- Q	% of headcount	100001
Long Term Incentive- PGE	Grant elections	100007
IT- Corporate Executive	Billed on actuals	100010
HR Support Services	% of headcount	100013
State Tax Group	State tax returns, anticipated resources	100026
Corporate Secretary	Anticipated resources, company numbers	100030
HRIS	% of headcount	100033
Intellectual Capital	Histrocial data, transaction count	100035
Risk Mgmt- Research Group	History	100038
Legal - Litigations	Billed on actuals	100039
Corporate Legal	Billed on actuals	100040
Enrvironmental Legal	Anticipated resources	100041
VP- HR Administration	% of headcount	100050
IT Information Services	Billed on actuals	100051
RAC- Global Credit Group	Anticipated resources	100052
RAC- Due Dilligence	Anticipated resources	100053
RAC- Risk Analytics	Anticipated resources	100054
Staffing	Anticipated resources	100058
Management Conference	% of attendees	100066
RAC- Risk Mgmt Control	Historical data	100068
Savings Plan (billed on actuals)	Billed on actuals	100083
Labor Relations Risk Management	Anticipated resources	100092
Fair Employment and Practices	% of headcount	100110
Restricted Stock	Billed on actuals	100112
NQ Stock Plan	Awards grants	100113
All Employee Stock Option Program	5% of estimated payroll	100118
EE Life, AD&D	Billed on actuals	100120
Long Term Disability	Billed on actuals	100121
Active Medical/Dental	Billed on actuals	100124
Flex Admin/BTA	Included in benefits rate	100125
Professional Accounting Fees	Contract specific, MMF	100127
ASO Charges	Included in benefits rate	100128
Employee Communications	% of headcount	100135
Matching Gifts .	Billed on actuals	100138
SAP COE Control Group	Set by steering committee	100216
EARN Risk Management	Anticipated resources	100225
IT Communications & Market Data	Billed on actuals	100242
IT Infrastructure & Integration	Billed on actuals	100243
IT Corporate Applications Development	Billed on actuals	100244
ECM - Insurance Premiums	Billed on actuals	100255
SAP Costs- Project Apollo	Billed on actuals	

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Enron Allocations & Direct Charges - 2000 Budget to 2002 Test Period

Description	2000 Per Enron Budget (1)	Adjustments to 2000 (2)	2000 PGE Budget (3)	Inflation (4)	2001 PGE Budget (5)	Inflation (6)	2002 PGE Budget (7)	Regulatory Adjustments (8)	2002 PGE Test Year (9)
MMF Allocations:									
HUMAN RESOURCES:									
Benefits & Compensation	72,000		72,000	2.3%	73,656	2.4%	75,424		75,424
Long Term Incentive	259,000		259,000	2.3%	264,957	2.4%	271,316		271,316
Drug/Alcohol Testing	5,000		5,000	2.3%	5,115	2.4%	5,238		5,238
HR Support Services	40,000		40,000	2.3%	40,920	2.4%	41,902		41,902
Workforce Diversity	98,000		98,000	2.3%	100,254	2.4%	102,660		102,660
HRIS	116,000		116,000	2.3%	118,668	2.4%	121,516		121,516
VP - HR Administration	46,000		46,000	2.3%	47,058	2.4%	48,187		48,187
HR & Community Relations- Executive	104,000		104,000	2.3%	106,392	2.4%	108,945		108,945
Fair Employment Practices	27,000		27,000	2.3%	27,621	2.4%	28,284		28,284
Annual Incentive	1,723,000		1,723,000	2.3%	1,762,629	2.4%	1,804,932		1,804,932
Exec Perqs	40,000		40,000	2.3%	40,920	2.4%	41,902	(41,902)	-
Employee Performance Awards	41,000		41,000	2.3%	41,943	2.4%	42,950		42,950
Staffing	251,000		251,000	2.3%	256,773	2.4%	262,936		262,936
Labor Relations Risk Management	14,000		14,000	2.3%	14,322	2.4%	14,666		14,666
Vision & Values Task Force	25,000		25,000	2.3%	25,575	2.4%	26,189		26,189
Organization Planning & Performance	97,000		97,000	2.3%	99,231	2.4%	101,613		101,613
Total - HR	2,958,000	-	2,958,000		3,026,034		3,098,659	(41,902)	3,056,757
CORPORATE COMMUNICATIONS:									
Corporate Memberships	95,000		95,000	2.3%	97,185	2.4%	99,517		99,517
Matching Gifts	123,000		123,000	2.3%	125,829	2.4%	128,849	(128,849)	-
Community Relations	409,000		409,000	2.3%	418,407	2.4%	428,449		428,449
Community Relations Programs	57,000		57,000	2.3%	58,311	2.4%	59,710		59,710
Community Relations- Employee Events	23,000		23,000	2.3%	23,529	2.4%	24,094	(24,094)	-
Total - Corp Comm	707,000	-	707,000		723,261		740,619	(152,943)	587,677
INVESTOR RELATIONS:									
Investor Relations	439,000		439,000	2.3%	449,097	2.4%	459,875		459,875
Public Relations- Annual Report	147,000		147,000	2.3%	150,381	2.4%	153,990		153,990
Public Relations- Corporate Communications	336,000		336,000	2.3%	343,728	2.4%	351,977		351,977
Public Relations- Employee Communications	8,000		8,000	2.3%	8,184	2.4%	8,380		8,380
Executive Board Meeting Expenses	317,000		317,000	2.3%	324,291	2.4%	332,074		332,074
Total - Investor Relations	1,247,000	-	1,247,000		1,275,681		1,306,297	-	1,306,297

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Enron Allocations & Direct Charges - 2000 Budget to 2002 Test Period

Description	2000 Per Enron Budget (1)	Adjustments to 2000 (2)	2000 PGE Budget (3)	Inflation (4)	2001 PGE Budget (5)	Inflation (6)	2002 PGE Budget (7)	Regulatory Adjustments (8)	2002 PGE Test Year (9)
FINANCE & ACCOUNTING:									
Sr. Vice President - CAO	156,000		156,000	2.3%	159,588	2.4%	163,418		163,418
Accounts Payable- Executive	12,000		12,000	2.3%	12,276	2.4%	12,571		12,571
Vice President - Tax	748,000		748,000	2.3%	765,204	2.4%	783,569		783,569
Ad Valorem Tax	44,000		44,000	2.3%	45,012	2.4%	46,092		46,092
State Tax Group	5,000		5,000	2.3%	5,115	2.4%	5,238		5,238
Tax- Analyst/Intern Recruiting	97,000		97,000	2.3%	99,231	2.4%	101,613		101,613
RAC- Global Credit Group	36,000		36,000	2.3%	36,828	2.4%	37,712		37,712
IT - Technology Training	21,000		21,000	2.3%	21,483	2.4%	21,999		21,999
SAP Costs Related to Project Apollo	494,000		494,000	2.3%	505,362	2.4%	517,491		517,491
SAP COE Control Group	326,000		326,000	2.3%	333,498	2.4%	341,502		341,502
Accounts Payable- MSA/SAP	78,000		78,000	2.3%	79,794	2.4%	81,709		81,709
Sales & Use Tax	4,000		4,000	2.3%	4,092	2.4%	4,190		4,190
Professional Accounting Fees	305,000		305,000	2.3%	312,015	2.4%	319,503		319,503
Corporate Accounting & Reporting	576,000		576,000	2.3%	589,248	2.4%	603,390		603,390
Total - Finance & Accounting	2,902,000	-	2,902,000		2,968,746		3,039,996	-	3,039,996
LEGAL & REGULATORY:									
Corporate Secretary	482,000		482,000	2.3%	493,086	2.4%	504,920		504,920
Corporate Legal	162,000		162,000	2.3%	165,726	2.4%	169,703		169,703
Environmental Legal	5,000		5,000	2.3%	5,115	2.4%	5,238		5,238
Legal Library	22,000		22,000	2.3%	22,506	2.4%	23,046		23,046
American Indian Affairs- Govt Affairs	1,000		1,000	2.3%	1,023	2.4%	1,048	(1,048)	-
Federal Government Affairs	498,000		498,000	2.3%	509,454	2.4%	521,681	(521,681)	-
Total - Legal & Regulatory	1,170,000	-	1,170,000		1,196,910		1,225,636	(522,728)	702,907
MISCELLANEOUS:									
Health Center	32,000		32,000	2.3%	32,736	2.4%	33,522	(33,522)	-
Vacant Space	68,000		68,000	2.3%	69,564	2.4%	71,234		71,234
Houston Children's Chorus	9,000		9,000	2.3%	9,207	2.4%	9,428	(9,428)	-
United Way Campaign	90,000		90,000	2.3%	92,070	2.4%	94,280	(94,280)	-
Best Buddies	2,000		2,000	2.3%	2,046	2.4%	2,095	(2,095)	-
Wind Down- Omaha	2,000		2,000	2.3%	2,046	2.4%	2,095	(2,095)	-
Teach for America	10,000		10,000	2.3%	10,230	2.4%	10,476	(10,476)	-
Support Services (Co 423 Charges)	25,000		25,000	2.3%	25,575	2.4%	26,189		26,189
Insurance Preimiums	423,000		423,000	2.3%	432,729	2.4%	443,114		443,114
Work Life	34,000		34,000	2.3%	34,782	2.4%	35,617	(35,617)	-
Total - Miscellaneous	695,000	-	695,000		710,985		728,049	(187,512)	540,537
EXECUTIVE SERVICES:									
Executive Reception	95,000		95,000	2.3%	97,185	2.4%	99,517		99,517
Management Conference	28,000		28,000	2.3%	28,644	2.4%	29,331		29,331
Chairman and CEO	563,000		563,000	2.3%	575,949	2.4%	589,772		589,772
Corporate Aircraft Usage	282,000		282,000	2.3%	288,486	2.4%	295,410	(295,410)	-
Vice Chairman (Sutton)	434,000		434,000	2.3%	443,982	2.4%	454,638		454,638
Corp Billing RC (EOC/MSA & ECM)	219,000		219,000	2.3%	224,037	2.4%	229,414		229,414
Total - Executive Services	1,621,000	-	1,621,000		1,658,283		1,698,082	(295,410)	1,402,672
Sub-Total of MMF method	11,300,000	-	11,300,000		11,559,900		11,837,338	(1,200,495)	10,636,843

Enron Allocations & Direct Charges - 2000 Budget to 2002 Test Period

Description	2000 Per Enron Budget	Adjustments to 2000	2000 PGE Budget	Inflation	2001 PGE Budget	Inflation	2002 PGE Budget	Regulatory Adjustments	2002 PGE Test Year
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Direct Charges:									
Benefits & Compensation- Q	952,000		952,000	2.3%	973,896	2.4%	997,270		997,270
Long Term Incentive- PGE	294,000	(103,000)	191,000	2.3%	195,393	2.4%	200,082		200,082
IT- Corporate Executive	22,000		22,000	2.3%	22,506	2.4%	23,046		23,046
HR Support Services	447,000		447,000	2.3%	457,281	2.4%	468,256		468,256
State Tax Group	50,000		50,000	2.3%	51,150	2.4%	52,378		52,378
Corporate Secretary	13,000		13,000	2.3%	13,299	2.4%	13,618		13,618
HRIS	150,000		150,000	2.3%	153,450	2.4%	157,133		157,133
Intellectual Capital	16,000		16,000	2.3%	16,368	2.4%	16,761		16,761
Risk Mgmt- Research Group	20,000		20,000	2.3%	20,460	2.4%	20,951		20,951
Legal - Litigations	12,000	(12,000)	-	2.3%	-	2.4%	-		-
Enrvironmental Legal	51,000		51,000	2.3%	52,173	2.4%	53,425		53,425
VP- HR Administration	398,000		398,000	2.3%	407,154	2.4%	416,925		416,925
IT Information Services	11,000	139	11,139	2.3%	11,395	2.4%	11,669		11,669
RAC- Global Credit Group	27,000		27,000	2.3%	27,621	2.4%	28,284		28,284
RAC- Due Dilligence	58,000		58,000	2.3%	59,334	2.4%	60,758		60,758
RAC- Risk Analytics	184,000		184,000	2.3%	188,232	2.4%	192,750		192,750
Management Conference	18,000		18,000	2.3%	18,414	2.4%	18,856		18,856
RAC- Risk Mgmt Control	35,000		35,000	2.3%	35,805	2.4%	36,664		36,664
Savings Plan (billed on actuals)	3,995,000	743,171	4,738,171	N/A	5,305,000	N/A	5,516,000		5,516,000
Fair Employment and Practices	94,000		94,000	2.3%	96,162	2.4%	98,470		98,470
Restricted Stock	443,000	307,000	750,000	2.3%	767,250	2.4%	785,664		785,664
NQ Stock Plan	557,000	(95,800)	461,200	2.3%	471,808	2.4%	483,131		483,131
All Employee Stock Option Program	4,211,000	(124,000)	4,087,000	N/A	5,731,000	N/A	5,952,000		5,952,000
EE Life, AD&D	653,000	(19,000)	634,000	N/A	781,595	N/A	805,356		805,356
Long Term Disability	408,000	(12,000)	396,000	N/A	488,506	N/A	503,356		503,356
Active Medical/Dental	7,097,000	(207,000)	6,890,000	N/A	8,499,899	N/A	8,758,288		8,758,288
Flex Admin/BTA	181,000	482	181,482	2.3%	185,656	2.4%	190,112		190,112
Professional Accounting Fees	950,000	10,000	960,000	2.3%	982,080	2.4%	1,005,650		1,005,650
ASO Charges	184,000	(4,660)	179,340	2.3%	183,465	2.4%	187,868		187,868
Employee Communications	78,000		78,000	2.3%	79,794	2.4%	81,709		81,709
Matching Gifts	10,000	(10,000)	-	2.3%	-	2.4%	-		-
SAP COE Control Group	1,500,000		1,500,000	2.3%	1,534,500	2.4%	1,571,328		1,571,328
EARN Risk Management	27,000	(1,000)	26,000	N/A	24,000	N/A	25,000		25,000
IT Communications & Market Data	242,000		242,000	2.3%	247,566	2.4%	253,508		253,508
IT Infrastructure & Integration	112,000		112,000	2.3%	114,576	2.4%	117,326		117,326
IT Corporate Applications Development	129,000		129,000	2.3%	131,967	2.4%	135,134		135,134
ECM - Insurance Premiums	710,000	(30,482)	679,518	N/A	754,265	N/A	791,526		791,526
SAP Costs- Project Apollo	2,000,000	(603,310)	1,396,690	2.3%	1,428,814	2.4%	1,463,105		1,463,105
Sub-Total of Direct Charges	26,339,000	(161,460)	26,177,540		30,511,834		31,493,357	-	31,493,357
Grand Total	37,639,000	(161,460)	37,477,540		42,071,734		43,330,694	(1,200,495)	42,130,200

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CORPORATE CHARGES

CC #	CC Name	CC Function
100001	Benefits & Compensation	Administer benefits and compensation programs
100007	Long Term Incentive	Administer Exec. Long Term incentive programs
100008	Drug/Alcohol Testing	Administer Drug/Alcohol testing
100010	IT - Corp. Executive	Capture IT executive expenses
100012	Corp Acct., Planning, & Reporting	Oversee consolidated Corp. accting, planning and reporting
100013	HR Support Services	Administer payroll
100016	Sr. VP - Chief Accouting Officer	Capture Sr. VP - CAO executive expenses
100019	Community Relations	Administer/oversee community relations programs
100020	Executive Reception	Capture expenses for outside executive receptions
100022	Diversity	Administer/oversee diversity programs
100024	Investor Relations	Oversee Investor Relations activities
100026	State Tax Group	Administer preparation of State taxes
100027	Vice President - Tax	Capture VP - Tax executive expenses
100029	Ad Valorem Tax	Administer preparation of Ad Valorem taxes
100030	Corporate Secretary	Maintains corporate legal filings
100033	H.R.I.S.	Oversee HR Information Systems
100035	Intellectual Capital	Administer executive leadership and training programs
100034	Health Center	Administer Health Care Services
100038	Risk Mgmt - Research Group	Provides independent research related to Corp. risk management issues
100039	Legal - Litigations	Oversee litigation work for Corp. companies/business units
100040	Corporate Legal	Oversee corporate legal activities
100041	Environmental Legal	Oversee environmental related legal activities
100042	Federal Gov't Affairs	Oversee Federal government affairs activities
100044	Chairman & CEO	Capture Chairman & CEO executive expenses
100045	Tax - Analyst/Intern Recruiting	Administer recruiting for Tax analysts/associates
100050	VP - HR Administration	Capture VP HR executive expenses
100051	IT Information Services	Oversee all data communications (networks, server connections, etc.)
100052	RAC - Global Credit Group	Provides independent credit risk management for trading activities
100053	RAC - Due Diligence Group	Oversee financial & administrative risks in proposed transactions
100054	RAC - Risk Analytics	Provides independent analysis of capital transactions
100056	Community Relations Programs	Administer Volunteer & Community Outreach
100058	Staffing	Oversee recruiting and staffing for Corp./business units
100064	Vacant Space	Capture allotment for vacant office space
100065	Houston Children's Chorus	Oversee Houston Children's Chorus program
100066	Management Conference	Oversee Management Conference
100068	RAC - Risk Mgmt Control	Oversee and administer Enron Corp. risk policy
100069	United Way Campaign	Administer United Way Campaign
100070	Community Relations - Employee Events	Administer Employee Events
100076	Best Buddies	Oversee Best Buddies program
100077	Organization Planning & Performance	Oversee HR generalists - handle employee matters, PRC, etc.
100081	Corp. Billing RC(EOC/MSA & ECM)	Capture charges from Global Finance - banking fees
100083	Savings Plan	Administer Savings Plan - 401(k) match

CORPORATE CHARGES

CC #	CC Name	CC Function
100092	Labor Relations Risk Management	Oversee collective bargining employee issues
100103	IT - Technology Training	Oversee and provide IT training
100105	American Indian Affairs - Gov't Affairs	Oversee American Indian and Government affairs activities
100109	Wind Down - Omaha	Capture expenses related to closing of Corp. Omaha office
100110	Fair Employment Practices	Oversee compliance with Fair Employment Practice guidelines
100112	Restricted Stock	Oversee Restricted Stock Plan
100113	NQ Stock	Oversee Non-Qualified Stock Plan
100114	Annual Incentive	Oversee annual incentive bonuses
100115	Executive Perqs	Capture expenses related to Exec. Perqs
100116	Employee Performance Award	Administer award programs (ie: PBA awards)
100118	All Employee Stock Option Plan	Administer All Employee Stock Option plan
100120	EE Life, AD&D	Administer EE Life, AD&D Plan
100121	Long Term Disability	Administer Long Term Disability Plan
100124	Active Medical/Dental	Administer Active Medical/Dental Plan
100125	Flex Admin/BTA	Administer Flex Admin/BTA Plan
100127	Professional Accounting Fees	Administer Corp. auditing function
100128	ASO Charges	Oversee Charges from Admin. Organizational Services
100132	Teach for America	Administer Teach for America program
100134	Corporate Memberships	Oversee charges for memberships for prof/trade organizations
100135	Public Relations - Employee Communications	Administer Business Communications to Employees
100136	Public Relations - Annual Report	Oversee publication of the Annual Report
100137	Public Reations - Corp. Communications	Administer Corp. communications to third parties
100138	Matching Gifts	Administer Employee Matching Gift Program
100139	Legal Library	Maintain legal library
100140	Executive Board Meeting Exp	Oversee expenses for ENE board meetings
100207	Corporate Aircraft Usage	Oversee Corp. aircraft usage and expenses
100211	Support Services (Co. 423 charges)	Capture charges from GPG - MSA data related
100216	SAP COE Control Group	Oversee SAP System
100218	HR & Community Relations	Capture HR & Community Relations executive expenses
100220	Accounts Payable - MSA/SAP	Administer AP Processing
100225	EARN Risk Management	Manage Energy, Communications & Alternative Risks
100230	Vision & Values Task Force	Administer initiatives related to company Vision & Values
100242	IT Communications & Market Data	Oversee IT related communications & market data expenses
100243	IT Infrastructure & Integration	Oversee IT infrastructure development and integration
100244	IT Corporate Applications Development	Oversee corporate IT applications development
100255	Insurance Premiums	Oversee Insurance Premiums
100280	Sales & Use Tax	Administer preparation of Sales & Use taxes
100281	Vice Chairman - Sutton	Capture Vice Chairman (Sutton) executive expenses
100801	Accounts Payable - Executive	Oversee AP Process
100805	Work Life	Administer Work Life programs
	SAP Costs Related to Project Apollo	Implementation of SAP System

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Corporate Staff and Service Group Analysis
Summary
2000 Operating Budgets
In thousands of dollars, except headcount

CO.	COST CENTER NAME/DESCRIPTION	CC Owner	SAP CC #	Sal, PR, Ben, Tax	T&E	Supply	Gen Business	EIS	EPSC	Other	2000 Budget
0001	Benefits & Compensation	Joyce, Mary	100001	3,546	411	41	942		814	(663)	5,091
0001	EMI Billing R/C (ECM)	Lindsey, Mark	100003	-	-	-	-		-	284	284
0001	Deferral Plans	Joyce, Mary	100005	10,434	-	-	-		-	-	10,434
0011	Long Term Incentive	Joyce, Mary	100007	-	-	-	-		-	11,462	11,462
0011	Drug/Alcohol Testing	Gonzales, Paul	100008	142	19	27	174		31	(24)	369
0011	Executive Consultants	Urquhart, Jack	100009	-	-	-	1,568		-	-	1,568
0011	IT - Corporate Executive	Bibi, Philippe	100010	-	-	-	-		-	2,596	2,596
0011	EDS Corp Support Costs	Bibi, Philippe	100011	-	-	-	250		-	-	250
0011	Corp Accounting, Planning, & Reporting	Butts, Bob	100012	2,824	65	86	300		533	-	3,808
0011	HR Support Services	O'Dell, David	100013	1,607	58	27	81		313	(257)	1,829
0011	RAC - Engineering Group	Buy, Rick	100014	2,087	268	40	41		238	140	2,814
0011	Sr. VP - Chief Accounting Officer	Causey, Rick	100016	1,097	400	7	82		133	-	1,719
0011	President and COO	Skilling,Jeff	100017	1,281	110	36	990		132	-	2,549
0011	Vice Chairman	Urquhart, Jack	100018	115	8	4	-		67	-	194
0011	Community Relations	Kalmans, Elyse	100019	1,369	206	78	176		340	(14)	2,155
0011	Executive Reception	Lay, Ken	100020	141	259	48	475		76	-	999
0011	Political Action Committee	Wheeler, Terrie	100021	-	3	6	107		61	9	186
0011	Diversity	Eakins, Calvin	100022	301	76	9	90		39	-	515
0011	Investor Relations	Koeing, Mark	100024	1,125	243	75	408		509	-	2,360
0011	State Tax Group	Rice, Greek	100026	345	25	7	62		60	-	499
0011	Vice President - Tax	Herman, Bob	100027	3,940	464	25	1,721		600	155	6,905
0011	Corporate Development	Metts, Mark	100028	2,116	665	-	41		225	335	3,382
0011	Ad Valorem Tax	Russo, Gavin	100029	788	169	6	75		123	-	1,161
0011	Corporate Secretary	Carter, Rebecca	100030	1,506	35	6	2,428		234	-	4,209
0011	MLP Services	Davis, Hardie	100031	334	18	6	106		55	-	519
0011	Credit Union	Lindsey, Mark	100032	-	3	10	1		192	(206)	-
0011	H.R.I.S.	Lessner, Sherry	100033	1,389	85	40	1,925		789	(112)	4,116
0011	Health Center	James, Terrie	100034	56	16	314	309		101	(78)	718
0011	Intellectual Capital	Amabile, Dick	100035	407	300	72	515		192	-	1,486
0011	Risk Mgmt - Research Group	Kaminiski, Vince	100038	5,696	254	212	199		500	188	7,049
0011	Legal - Litigations	Cheek, Chuck	100039	2,016	100	15	1,612		388	-	4,131
0011	Corporate Legal	Derrick, Jim	100040	3,463	350	41	737		417	-	5,008
0011	Environmental Legal	Smith, Frank	100041	424	22	1	12		52	-	511
0011	Federal Government Affairs	Hillings, Joe	100042	1,334	540	84	2,883		31	-	4,872
0011	Chairman and CEO	Lay, Ken	100044	2,300	165	-	176		321	-	2,962
0011	Tax - Analyst/Intern Recruiting	Coats, Ed	100045	1,517	73	3	11		5	-	1,609
0011	Public Relations - Advertising	Palmer, Mark	100046	-	-	-	17,650		-	-	17,650
0011	VP - HR Administration	Lynch, Drew	100050	-	-	-	-		-	1,626	1,626
0011	IT Iinormation Services	Bibi, Philippe	100051	-	-	-	-		-	12,978	12,978
0011	RAC - Global Credit Group	Buy, Rick	100052	1,568	342	75	320		204	199	2,708
0011	RAC - Due Diligence/Asset Management	Buy, Rick	100053	1,215	217	25	45		138	288	1,928
0011	RAC - Risk Analytics	Buy, Rick	100054	2,023	124	25	40		251	605	3,068
0011	RAC Underwriting	Buy, Rick	100055	1,478	178	12	59		152	370	2,249

Corporate Staff and Service Group Analysis
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CO.	COST CENTER NAME/DESCRIPTION	CC Owner	SAP CC #	Sal, PR, Ben, Tax	T&E	Supply	Gen Business	EIS EPSC	Other	2000 Budget
0011	Community Relations Programs	Kalmans, Elyse	100056	-	-	-	1,270	-	-	1,270
0011	Staffing	Fenninger, Kathleen	100058	231	22	24	288	69	2,894	3,528
0011	Federal Regulatory Affairs	Hartsoe, Joe	100059	-	390	75	160	-	-	625
0011	Env. & Intl Govt Affairs	Thorn, Terry	100060	544	328	6	230	120	-	1,228
0011	Sr. VP - Governmental Affairs	Kean, Steve	100061	1,452	219	190	214	300	-	2,375
0011	Electricity Regulatory Affairs	Shapiro, Rick	100062	7,916	325	65	10,855	348	-	19,509
0901	Vacant Space	Lindsey, Mark	100064	-	-	-	-	360	-	360
0011	Houston Children's Chorus	Lindsey, Mark	100065	-	-	-	-	48	-	48
0011	Management Conference	Lay, Ken	100066	-	706	-	-	20	-	726
0011	RAC Risk Management Control	Buy, Rick	100068	1,548	600	36	1,000	146	201	3,531
0011	United Way Campaign	Kalmans, Elyse	100069	-	-	-	2,160	-	-	2,160
0011	Community Relations - Employee Events	Olson, Cindy	100070	-	-	-	403	100	-	503
0011	Asset Operations	Huneke, Kurt	100071	386	151	7	39	110	-	693
0011	State Govt Affairs - TX,OK,AR,LA	Shapiro, Rick	100072	-	300	100	20	-	-	420
0011	Public Relations - Astros	Palmer, Mark	100073	-	-	-	3,300	-	-	3,300
0011	International Benefits	Joyce, Mary	100075	2,876	-	-	-	-	-	2,876
0011	Best Buddies	Lindsey, Mark	100076	-	-	-	-	9	-	9
0011	Organization Planning & Performance	Petteway, Gwen	100077	406	41	3	-	73	290	813
0011	EMS Analysts Recruiting	Roberts, Celeste	100078	491	596	20	149	181	198	1,635
0011	SAP Implemenation (Project Apollo)	Kokas, Kathy	100079	1	102	-	1	1,174	(1,174)	104
0011	Corp Billing R/C (EOC/MSA & ECM)	Lindsey, Mark	100081	-	-	-	-	-	5,151	5,151
0011	Savings Plan	Joyce, Mary	100083	22,035	-	-	-	-	-	22,035
0011	State Govt Affairs - California/West	Shapiro, Rick	100085	-	315	120	270	-	-	705
0011	State Govt Affairs - Canada	Shapiro, Rick	100086	331	100	40	45	-	-	516
0011	State Govt Affairs - Mid Atl/NY/NE	Shapiro, Rick	100087	-	600	125	100	-	-	825
0011	State Govt Affairs - Midwest/Great Lakes	Shapiro, Rick	100088	-	400	50	100	-	-	550
0011	Corp IT Compliance & Systems Risk Mgmt	Gude, Alberto	100091	810	85	6	155	41	-	1,097
0011	Labor Relations Risk Management	Gonzales, Paul	100092	181	64	1	43	-	-	289
0011	Risk Management - Executive	Whalley, Greg	100097	427	218	12	102	95	-	854
0011	Gov't Affairs - Mexico	Kean, Steve	100100	223	40	12	131	-	-	406
0011	Public Relations - Internet Marketing	Palmer, Mark	100102	-	-	5	875	-	-	880
0011	IT - Technology Training	Busch, Debbie	100103	361	46	27	91	290	46	861
0011	American Indian Affairs - Gov't Affairs	Kean, Steve	100105	656	569	25	148	40	(1,435)	3
0011	Other G&A costs	Lindsey, Mark	100106	-	-	-	-	-	-	-
0011	State Gov't / Fed Reg Env / Implementaion	Shapiro, Rick	100108	-	300	30	20	-	-	350
0011	Wind Down - Omaha	Lindsey, Mark	100109	12	-	-	-	-	-	12
0011	Fair Employment Practices	Gonzales, Paul	100110	465	36	6	55	159	(50)	671
0011	1992 Deferral Plan	Joyce, Mary	100111	-	-	-	-	-	119	119
0011	Restricted Stock	Joyce, Mary	100112	-	-	-	-	-	78,109	78,109
0011	NQ Stock Plan	Joyce, Mary	100113	-	-	-	-	-	77,963	77,963
0011	Annual Incentive	Joyce, Mary	100114	-	-	-	-	-	100,364	100,364
0011	Executive Perqs	Joyce, Mary	100115	-	-	-	-	-	210	210
0011	Employee Performance Award	Joyce, Mary	100116	-	-	-	-	-	215	215
0011	1994 Deferral Plan	Joyce, Mary	100117	-	-	-	-	-	10,000	10,000

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Corporate Staff and Service Group Analysis
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CO.	COST CENTER NAME/DESCRIPTION	CC Owner	SAP CC #	Sal, PR, Ben, Tax	T&E	Supply	Gen Business	EIS	EPSC	Other	2000 Budget
0011	All Employee Stock Option Plan	Joyce, Mary	100118	33,109	-	-	-		-	-	33,109
0011	Cash Balance/SERP	Joyce, Mary	100119	20,996	-	-	-		-	-	20,996
0011	EE Life, AD&D	Joyce, Mary	100120	3,865	-	-	-		-	-	3,865
0011	Long Term Disability	Joyce, Mary	100121	2,416	-	-	-		-	-	2,416
0011	ESOP/Savings Plan Admin Fees	Joyce, Mary	100122	235	-	-	-		-	-	235
0011	Inactive Medical FAS 106	Joyce, Mary	100123	16,003	-	-	-		-	-	16,003
0011	Active Medical/Dental	Joyce, Mary	100124	42,036	-	-	-		-	-	42,036
0011	Flex Admin/BTA	Joyce, Mary	100125	1,075	-	-	-		-	-	1,075
0011	Executive Supplemental/COLI	Joyce, Mary	100126	-	-	-	-		-	-	-
0011	Professional Accounting Fees	Wheeler, Terrie	100127	-	-	-	11,531		-	-	11,531
0011	ASO Charges	Joyce, Mary	100128	4,567	-	-	-		-	-	4,567
0011	Teach For America	Lindsey, Mark	100132	-	-	-	-		52	-	52
0011	Contributions, Tables, Multi-Years	Kalmans, Eylse	100133	-	-	-	2,912		-	-	2,912
0011	Corporate Memberships	Kalmans, Eylse	100134	-	-	-	500		-	-	500
0011	Public Relations - Employee Comm.	Palmer, Mark	100135	-	46	5	629		52	-	732
0011	Public Relations - Annual Report	Palmer, Mark	100136	-	4	767	-		3	-	774
0011	Public Relations - Corp Communications	Palmer, Mark	100137	1,451	207	127	440		293	-	2,518
0011	Matching Gifts	Kalmans, Eylse	100138	-	-	-	1,500		-	-	1,500
0011	Legal Library	Hu, Sylvia	100139	119	4	26	318		265	-	732
0011	Executive Board Meeting Exp	Davis, Hardie	100140	-	25	-	2,751		16	-	2,792
0011	Body Shop / Wellness	James, Terrie	100141	-	78	42	682		699	(522)	979
0011	Employee Recreation	James, Terrie	100142	-	207	-	-		-	-	207
0011	Fuji Lease	Lindsey, Mark	100143	-	-	-	-		2,531	-	2,531
0011	International Graphics	Feener, Lisa	100144	621	107	200	506		-	-	1,434
0011	Intl PR, Marketing, & Communications	Kimberly, Kelly	100145	564	201	50	2,401		44	-	3,260
0011	Conventions/Inauguration	Kean, Steve	100178	-	300	-	1,163		-	-	1,463
0011	Corporate Aircraft Usage	Lay, Ken	100207	-	120	264	-		6,100	-	6,484
0011	Support Services (Co 423 Charges)	Lindsey, Mark	100211	-	-	-	-		-	134	134
0011	SAP COE Control Group	Nikkel, Greg	100216	4,539	1,112	72	4,812		968	514	12,017
0011	HR & Community Relations - Executive	Olson, Cindy	100218	-	-	-	-		-	546	546
0011	Accounts Payable - MSA/SAP	Dallman, Larry	100220	1,365	31	17	90		440	(104)	1,839
0011	Environment	Thorn, Terry	100222	385	177	9	488		30	-	1,089
0011	Environment Policy & Compliance	Thorn, Terry	100223	658	363	40	983		-	-	2,044
0011	EARN Risk Management	Boullion, Jim	100225	1,442	260	21	124		230	170	2,247
0011	EARN Executive	Overdyke, Jere	100227	1,573	174	66	991		150	740	3,694
0011	Accounts Payable - SUN System	Knepshield, Judy	100229	550	7	15	81		111	-	764
0011	Vision & Values Task Force	Lay, Ken	100230	-	6	-	84		-	43	133
0011	International Government Affairs	Thorn, Terry	100231	862	367	11	30		60	-	1,330
0011	International Regulatory Affairs	Thorn, Terry	100232	1,184	558	14	437		80	-	2,273
0011	International Project Finance	Thorn, Terry	100233	567	288	40	290		-	-	1,185
0011	Strategic Initiatives	Becker, Melissa	100236	765	89	12	1,561		144	(500)	2,071
0011	SAP HR Project	Yowman, Andrea	100237	(23)	60	-	-		753	(790)	-
0011	MS Analysts Program	Arthur, Tracy	100238	-	-	-	-		-	-	-
0011	IT Communications & Market Data	Sarkissian, Arshak	100242	-	-	-	-		-	25,097	25,097

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CO.	COST CENTER NAME/DESCRIPTION	CC Owner	SAP CC #	Sal, PR, Ben, Tax	T&E	Supply	Gen Business	EIS EPSC	Other	2000 Budget
0011	IT Infrastructure & Integration	Tollesfsen	100243	-	-	-	-	-	13,124	13,124
0011	IT Corporate Applications Development	Bruce, Dan	100244	-	-	-	-	-	6,211	6,211
0011	EARN Origination	Overdyke, Jere	100245	540	101	18	308	114	1,167	2,248
0011	MD Recruiting & Resource Mgmt	Jackson, Charlene	100246	-	-	-	-	-	500	500
0011	Enron Technology Executive	McConnell, Mike	100277	1,733	659	12	40	222	-	2,666
0011	Asset Ops - Development Support	Huneke, Kurt	100250	706	267	19	261	335	-	1,588
0011	Asset Ops - Construction Support	Simpson, Bill	100251	684	202	15	52	171	-	1,124
0011	Asset Ops - EHS	Van, Henry	100252	1,213	1,117	34	365	125	-	2,854
0011	Asset Ops - Quality Management	Hawkins, Don	100253	659	945	35	1,009	171	-	2,819
0011	Asset Ops - Operations Support	Noles, James	100254	2,707	1,718	15	320	276	-	5,036
0011	Insurance Premiums	Boullion, Jim	100255	-	-	-	-	-	29,651	29,651
0011	Sales & Use Tax	Rice, Greek	100280	277	61	4	42	106	9	499
0011	Vice- Chairman (Sutton)	Sutton, Joe	100281	872	1,165	80	545	121	-	2,783
0011	Accounts Payable - Executive	Ison, Jerry	100801	302	65	5	1	36	-	409
0011	Work Life	Roman de Meza, Mary Ar	100805	189	25	5	443	-	100	762
0011	A&A Recruits Expenses	Jackson, Charlene	100806	1,215	-	-	-	-	4,293	5,508
0011	A&A Recruiting	Jackson, Charlene	100807	969	2,231	-	666	293	(2,578)	1,581
0011	A&A Training & Development	Jackson, Charlene	100808	1,112	383	23	247	4	(1,069)	700
0011	A&A Operations	Jackson, Charlene	100809	750	15	87	312	293	167	1,624
0011	A&A Exec & Strategic Planning & Dev	Jackson, Charlene	100810	537	48	-	281	333	(499)	700
0011	SAP Costs Related to Project Apollo	Lindsey, Mark		-	-	-	-	-	16,400	16,400
	GRAND TOTAL			**256,725**	**26,617**	**4,598**	**99,031**	**27,620**	**395,786**	**810,377**

Corporate Staff and Service Group Analysis
Summary
2000 Operating Budgets
In thousands of dollars, except headcount

COST CENTER NAME/DESCRIPTION	SAP CC #	Assessment/Allocation Method	EMI	TW	FGT	EE&CC	Citrus	EOTT	EOG	Enron Pwr Ops	Northern Plains	NNG	GPG Executive	CF - Methanol	N.A.
Benefits & Compensation	100001	% of Headcount	24	80	146	280	16	-	-	-	87	437	122	61	628
EMI Billing R/C (ECM)	100003	Retained At EMI	284												
Deferral Plans	100005	Retained At Corp													
Long Term Incentive	100007	Grant Elections			56	225	150				206	394	901	150	375
Drug/Alcohol Testing	100008	% of New Hires, Random	2	26	22	16	2				13	67	4	4	106
Executive Consultants	100009	Retained At Corp													
IT - Corporate Executive	100010	% of service costs	4	5	27	52		43			14	54	192		1,099
EDS Corp Support Costs	100011	Retained At Corp													
Corp Accounting, Planning, & Reporting	100012	MMF													
HR Support Services	100013	% of Headcount	8	29	53	101	6	-	-	-	31	157	44	22	226
RAC - Engineering Group	100014	Anticipated Resources													1,829
Sr. VP - Chief Accounting Officer	100016	MMF													
President and COO	100017	MMF													
Vice Chairman	100018	MMF													
Community Relations	100019	MMF													
Executive Reception	100020	MMF													
Political Action Committee	100021	MMF													
Diversity	100022	MMF													
Investor Relations	100024	MMF						50							
State Tax Group	100026	State tax returns, anticipated resources		15	40	15						52			209
Vice President - Tax	100027	Anticipated Resources/MMF													
Corporate Development	100028	Retained at Corp													
Ad Valorem Tax	100029	Properties, Tax, & MMF		83	130							320		20	234
Corporate Secretary	100030	Anticipated Resources/Company Numbers						13					47		222
MLP Services	100031	MMF/MLP Direct						129			181				
Credit Union	100032	Retained At Corp													
H.R.I.S.	100033	% of Headcount	24	83	152	290	16	-	-	-	90	452	185	63	650
Health Center	100034	% of DT Headcount	7	7	8	43	5	-	-	-	-	18	33	1	177
Intellectual Capital	100035	Historical data & transaction count											209		413
Risk Mgmt - Research Group	100038	Historical data, groups supported										543			2,507
Legal - Litigations	100039	Usage						17	248				991		496
Corporate Legal	100040	Anticipated Resources				250									901
Environmental Legal	100041	Anticipated Resources										26	77		153
Federal Government Affairs	100042	Anticipated Resources													
Chairman and CEO	100044	MMF													
Tax - Analyst/Intern Recruiting	100045	Resources & Assignment											103		293
Public Relations - Advertising	100046	Retained At Corp													
VP - HR Administration	100050	% of Headcount	8	26	47	89	5	-	-	-	28	140	39	19	200
IT Information Services	100051	Usage (phone lines, etc.)		23	126			790			39	122	3,440		6,929
RAC - Global Credit Group	100052	Anticipated Resources				27							27		1,976
RAC - Due Diligence/Asset Management	100053	Anticipated Resources													1,235
RAC - Risk Analytics	100054	Anticipated Resources				31									1,473
RAC Underwriting	100055	Anticipated Resources													674
Community Relations Programs	100056	% of DT Headcount	12	12	13	77	8	-	-	-	-	32	58	1	313
Staffing	100058	Anticipated Resources													1,361
Federal Regulatory Affairs	100059	Anticipated Resources													312
Env. & Intl Govt Affairs	100060	Anticipated Resources													
Sr. VP - Governmental Affairs	100061	Retained At Corp													
Electricity Regulatory Affairs	100062	Anticipated Resources													9,303
Vacant Space	100064	MMF													
Houston Children's Chorus	100065	MMF													
Management Conference	100066	% of Attendees		2	7			10			7	16	23	1	116
RAC Risk Management Control	100068	Historical data, groups supported													1,765
United Way Campaign	100069	Actuals, Estimate on 1999 Co Matching	10	10	21	100	6				49	102	121		504
Community Relations - Employee Events	100070	% of DT Headcount	5	5	5	30	3	-	-	-	-	13	23	0	124
Asset Operations	100071	Direct support													62
State Govt Affairs - TX,OK,AR,LA	100072	Anticipated Resources													210

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COST CENTER NAME/DESCRIPTION	SAP CC #	Assessment/Allocation Method	EMI	TW	FGT	EE&CC	Citrus	EOTT	EOG	Enron Pwr Ops	Northern Plains	NNG	GPG Executive	CF - Methanol	N.A.
Public Relations - Astros	100073	Agreed by Executive Com											175		175
International Benefits	100075	% of International Headcount				338									
Best Buddies	100076	MMF													
Organization Planning & Performance	100077	MMF													
EMS Analysts Recruiting	100078	MMF/Prostaff Usage													212
SAP Implementation (Project Apollo)	100079	Retained at Corp													
Corp Billing R/C (EOC/MSA & ECM)	100081	MMF & Retained At Corp													
Savings Plan	100083	Included in benefits rate	85	295	490	1,454	63	990			315	1,475	463	87	3,738
State Govt Affairs - California/West	100085	Anticipated Resources													353
State Govt Affairs - Canada	100086	Anticipated Resources													258
State Govt Affairs - Mid Atl/NY/NE	100087	Anticipated Resources													413
State Govt Affairs - Midwest/Great Lakes	100088	Anticipated Resources													275
Corp IT Compliance & Systems Risk Mgmt	100091	Retained At Corp													
Labor Relations Risk Management	100092	Anticipated Resources				14		6					14		144
Risk Management - Executive	100097	Usage													285
Gov't Affairs - Mexico	100100	Anticipated Resources													406
Public Relations - Internet Marketing	100102	MMF													
IT - Technology Training	100103	Historical Usage		23	23							23			370
American Indian Affairs - Gov't Affairs	100105	Retained At Corp													
Other G&A costs	100106	MMF													
State Gov't / Fed Reg Env / Implementaion	100108	Anticipated Resources													175
Wind Down - Omaha	100109	Retained At Corp													
Fair Employment Practices	100110	% of Headcount	3	11	19	37	2	-	-	-	11	58	16	8	83
1992 Deferral Plan	100111	Retained At Corp													
Restricted Stock	100112	Grant Elections		41	142	863	44				159	365	631	35	20,259
NQ Stock Plan	100113	Awards grants		53	201	581	86	99			222	446	793	47	6,122
Annual Incentive	100114	Estimated payments / MMF (corp only)											7,096		31,203
Executive Perqs	100115	MMF													
Employee Performance Award	100116	MMF													
1994 Deferral Plan	100117	Retained At Corp													
All Employee Stock Option Plan	100118	5% of est. payroll	145	505	840	2,490	108				539	2,528	793	150	6,405
Cash Balance/SERP	100119	Included in benefits rate		(112)	558		71	2,180			299	4,249	230		4,958
EE Life, AD&D	100120	Included in benefits rate	20	69	126	242	13				75	377	105	23	542
Long Term Disability	100121	Included in benefits rate	13	43	79	151	8				47	236	66	14	339
ESOP/Savings Plan Admin Fees	100122	Included in benefits rate	1	4	8	15	1	34			5	24	7	1	34
Inactive Medical FAS 106	100123	Included in benefits rate	46	559	1,208	547	24				269	4,613	258	51	2,479
Active Medical/Dental	100124	Included in benefits rate	222	752	1,375	2,629	146				815	4,104	1,145	247	5,897
Flex Admin/BTA	100125	Included in benefits rate	6	19	35	67	4				21	105	29	6	151
Executive Supplemental/COLI	100126	Retained At Corp													
Professional Accounting Fees	100127	Contract Specific & MMF				200						785			3,950
ASO Charges	100128	Included in benefits rate	21	72	131	251	14	-	-	-	78	392	109	54	563
Teach For America	100132	MMF													
Contributions, Tables, Multi-Years	100133	Retained At Corp													
Corporate Memberships	100134	MMF													
Public Relations - Employee Comm.	100135	% of Total Employees	1	5	9	19	2	-	-	-	5	27	10	2	41
Public Relations - Annual Report	100136	MMF													
Public Relations - Corp Communications	100137	MMF													
Matching Gifts	100138	Matching gifts	6	6	11	36	9				38	63	35		290
Legal Library	100139	% DT Attorneys											95		264
Executive Board Meeting Exp	100140	MMF													
Body Shop / Wellness	100141	% of DT Headcount	9	9	10	59	6	-	-	-	-	25	45	1	241
Employee Recreation	100142	% of DT Headcount	2	2	2	13	1	-	-	-	-	5	10	0	51
Fuji Lease	100143	Based on Sys depreciation before lease - 8U		810	456						76	177			1,012
International Graphics	100144	Direct Usage				72									
Intl PR, Marketing, & Communications	100145	Direct Usage				98									
Conventions/Inauguration	100178	Retained At Corp													
Corporate Aircraft Usage	100207	MMF													
Support Services (Co 423 Charges)	100211	MMF													

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COST CENTER NAME/DESCRIPTION	SAP CC #	Assessment/Allocation Method	EMI	TW	FGT	EE&CC	Citrus	EOTT	EOG	Enron Pwr Ops	Northern Plains	NNG	GPG Executive	CF - Methanol	N.A.
SAP COE Control Group	100216	Determined by the Steering Com		180	300	1,500					120	690	-		1,200
HR & Community Relations - Executive	100218	MMF													
Accounts Payable - MSA/SAP	100220	Line Count		88	148					36	61	391		5	392
Environment	100222	Anticipated Resources													
Environment Policy & Compliance	100223	Retained At Corp													
EARN Risk Management	100225	Anticipated Resources	1	93	431	22	1					230	6	30	177
EARN Executive	100227	Retained At Corp													
Accounts Payable - SUN System	100229	Direct support for EI only													
Vision & Values Task Force	100230	MMF													
International Government Affairs	100231	Usage													
International Regulatory Affairs	100232	Usage													
International Project Finance	100233	Usage													
Strategic Initiatives	100236	MMF													
SAP HR Project	100237	Retained At Corp													
MS Analysts Program	100238	Retained At Corp													
IT Communications & Market Data	100242	Usage	78	48	257	1,029	1	61			205	781	615	3	7,909
IT Infrastructure & Integration	100243	Usage	5	32	154	63		33			49	106	96	3	6,385
IT Corporate Applications Development	100244	Usage	3	6	39	25		67			13	123	33	2	3,299
EARN Origination	100245	Retained At Corp													
MD Recruiting & Resource Mgmt	100246	Retained At Corp													
Enron Technology Executive	100277	Retained At Corp													
Asset Ops - Development Support	100250	Direct Usage													318
Asset Ops - Construction Support	100251	Direct Usage													257
Asset Ops - EHS	100252	Direct Usage													141
Asset Ops - Quality Management	100253	Direct Usage													806
Asset Ops - Operations Support	100254	Direct Usage													
Insurance Premiums	100255	Past Usage		1,792	4,769	913	20	438			8	5,305	161	483	3,938
Sales & Use Tax	100280	Anticipated Resources		7	121	184						115		53	
Vice- Chairman (Sutton)	100281	MMF													
Accounts Payable - Executive	100801	Prorata to MSA/SAP & SUN support CC's		14	23					6	10	62		1	62
Work Life	100805	% of DT Headcount	7	7	8	46	5	-	-	-	-	19	35	1	188
A&A Recruits Expenses	100806	Allocated based on Analyst & Assoc used													
A&A Recruiting	100807	Allocated based on Analyst & Assoc used													
A&A Training & Development	100808	Allocated based on Analyst & Assoc used													
A&A Operations	100809	Allocated based on Analyst & Assoc used													
A&A Exec & Strategic Planning & Dev	100810	Allocated based on Analyst & Assoc used													
SAP Costs Related to Project Apollo				240	400	2,000					160	930	-		2,000
GRAND TOTAL			1,083	6,079	13,227	17,585	846	4,960	248	42	4,345	31,773	19,710	1,648	155,834
Downtown			52	52	57	327	35					136	248	4	1,331
US			53	180	329	604	35				195	982	274	136	1,411
US & Expat			53	180	329	629	35				195	982	274	136	1,411
Total			53	190	344	714	61				195	1,007	376	67	1,530
Downtown			0.96%	0.96%	1.06%	6.06%	0.65%	0.00%	0.00%	0.00%	0.00%	2.52%	4.59%	0.07%	24.65%
US			0.47%	1.60%	2.92%	5.36%	0.31%	0.00%	0.00%	0.00%	1.73%	8.72%	2.43%	1.21%	12.53%
US & Expat			0.46%	1.57%	2.87%	5.50%	0.31%	0.00%	0.00%	0.00%	1.70%	8.58%	2.39%	1.19%	12.33%
Total			0.19%	0.70%	1.26%	2.62%	0.22%	0.00%	0.00%	0.00%	0.71%	3.69%	1.38%	0.25%	5.60%

Corporate Staff and Service Group Analysis
Summary
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COST CENTER NAME/DESCRIPTION	SAP CC #	Assessment/Allocation Method	EEDC	CF - MT8E	Global Products	NBP Services	LRCO	HPLP	EPSC	Enron Europe	EI	Consol	ECM	EES	PGE	ECI
Benefits & Compensation	100001	% of Headcount	5	26	42	-	18	-	-	12		332	42	432	952	148
EMI Billing R/C (ECM)	100003	Retained At EMI														
Deferral Plans	100005	Retained At Corp														
Long Term Incentive	100007	Grant Elections							94			250	275	531	294	200
Drug/Alcohol Testing	100008	% of New Hires, Random		9			3	10	1			13		29		
Executive Consultants	100009	Retained At Corp														
IT - Corporate Executive	100010	% of service costs	3	2	60			7	21	57		391	39	157	22	4
EDS Corp Support Costs	100011	Retained At Corp														
Corp Accounting, Planning, & Reporting	100012	MMF				25										
HR Support Services	100013	% of Headcount	2	9	15	-	7	-	-	4		119	15	155	447	53
RAC - Engineering Group	100014	Anticipated Resources								281		704				
Sr. VP - Chief Accounting Officer	100016	MMF														
President and COO	100017	MMF														
Vice Chairman	100018	MMF														
Community Relations	100019	MMF														
Executive Reception	100020	MMF														
Political Action Committee	100021	MMF														
Diversity	100022	MMF														
Investor Relations	100024	MMF														
State Tax Group	100026	State tax returns, anticipated resources												35	50	10
Vice President - Tax	100027	Anticipated Resources/MMF														
Corporate Development	100028	Retained at Corp														
Ad Valorem Tax	100029	Properties, Tax, & MMF		20										75		
Corporate Secretary	100030	Anticipated Resources/Company Numbers							13			222		20	13	13
MLP Services	100031	MMF/MLP Direct														
Credit Union	100032	Retained At Corp														
H.R.I.S.	100033	% of Headcount	6	27	44	-	19	-	-	12		445	43	447	150	153
Health Center	100034	% of DT Headcount	2	1	12	-	-	-	-	-		84	13	86	-	13
Intellectual Capital	100035	Historical data & transaction count										290		137	16	70
Risk Mgmt - Research Group	100038	Historical data, groups supported								203		813		949	20	
Legal - Litigations	100039	Usage				124			4			289		8	12	
Corporate Legal	100040	Anticipated Resources										1,002	250	501		501
Environmental Legal	100041	Anticipated Resources							26			51		77	51	
Federal Government Affairs	100042	Anticipated Resources								33		71				
Chairman and CEO	100044	MMF														
Tax - Analyst/Intern Recruiting	100045	Resources & Assignment										367		293		
Public Relations - Advertising	100046	Retained At Corp														
VP - HR Administration	100050	% of Headcount	2	8	13	-	6	-	-	4		106	13	138	398	47
IT Information Services	100051	Usage (phone lines, etc.)						2				13	16	548	[illegible]	7
RAC - Global Credit Group	100052	Anticipated Resources								217		191		27	27	27
RAC - Due Diligence/Asset Management	100053	Anticipated Resources								96		481		58	58	
RAC - Risk Analytics	100054	Anticipated Resources	61							184		675		92	184	31
RAC Underwriting	100055	Anticipated Resources								113		788		337		225
Community Relations Programs	100056	% of DT Headcount	3	2	21	-	-	-	-	-		149	22	152		24
Staffing	100058	Anticipated Resources														347
Federal Regulatory Affairs	100059	Anticipated Resources												313		
Env. & Intl Govt Affairs	100060	Anticipated Resources										981				
Sr. VP - Governmental Affairs	100061	Retained At Corp														
Electricity Regulatory Affairs	100062	Anticipated Resources												9,302		500
Vacant Space	100064	MMF														
Houston Children's Chorus	100065	MMF														
Management Conference	100066	% of Attendees		2						42		121	10	48	18	
RAC Risk Management Control	100068	Historical data, groups supported								706		496		353	35	176
United Way Campaign	100069	Actuals, Estimate on 1999 Co Matching	11					12	17			399				
Community Relations - Employee Events	100070	% of DT Headcount	1	1	8	-	-	-	-	-		59	9	60	-	9
Asset Operations	100071	Direct support								69		562				
State Govt Affairs - TX,OK,AR,LA	100072	Anticipated Resources												210		

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Public Relations - Astros	100073	Agreed by Executive Com								175		175		375		
International Benefits	100075	% of International Headcount			81							2,011				
Best Buddies	100076	MMF														
Organization Planning & Performance	100077	MMF														
EMS Analysts Recruiting	100078	MMF/Prostaff Usage			10							215		215		
SAP Implemenation (Project Apollo)	100079	Retained at Corp														
Corp Billing R/C (EOC/MSA & ECM)	100081	MMF & Retained At Corp														
Savings Plan	100083	Included in benefits rate	51	202	179		61	216	105	109		2,235	177	1,942	3,995	
State Govt Affairs - California/West	100085	Anticipated Resources												352		
State Govt Affairs - Canada	100086	Anticipated Resources												258		
State Govt Affairs - Mid Atl/NY/NE	100087	Anticipated Resources												412		
State Govt Affairs - Midwest/Great Lakes	100088	Anticipated Resources												275		
Corp IT Compliance & Systems Risk Mgmt	100091	Retained At Corp														
Labor Relations Risk Management	100092	Anticipated Resources												14		14
Risk Management - Executive	100097	Usage								285		285				
Gov't Affairs - Mexico	100100	Anticipated Resources														
Public Relations - Internet Marketing	100102	MMF														
IT - Technology Training	100103	Historical Usage										112		69		86
American Indian Affairs - Gov't Affairs	100105	Retained At Corp														
Other G&A costs	100106	MMF														
State Gov't / Fed Reg Env / Implementaion	100108	Anticipated Resources												175		
Wind Down - Omaha	100109	Retained At Corp														
Fair Employment Practices	100110	% of Headcount	1	3	6	-	2	-	-	2		44	6	57	94	20
1992 Deferral Plan	100111	Retained At Corp														
Restricted Stock	100112	Grant Elections	4	36				6		6,475		11,869		4,796	443	16,092
NQ Stock Plan	100113	Awards grants		36				15		1,144		6,557	649	1,357	557	50,248
Annual Incentive	100114	Estimated payments / MMF (corp only)										29,557		9,625		4,817
Executive Perqs	100115	MMF														
Employee Performance Award	100116	MMF														
1994 Deferral Plan	100117	Retained At Corp														
All Employee Stock Option Plan	100118	5% of est. payroll	88	345	306		104	370	181	188		3,829	303	3,327	4,211	797
Cash Balance/SERP	100119	Included in benefits rate						126		145		4,939		2,575		
EE Life, AD&D	100120	Included in benefits rate	5	52	37		16	58	30	10		372	36	373	653	128
Long Term Disability	100121	Included in benefits rate	3	33	23		10	36	19	6		232	23	233	408	80
ESOP/Savings Plan Admin Fees	100122	Included in benefits rate		3	2		1	4	2	1		23	2	23		8
Inactive Medical FAS 106	100123	Included in benefits rate	10	118	83		36	141	69	73		2,446	82	1,288		290
Active Medical/Dental	100124	Included in benefits rate	50	568	397		171	627	330	113		4,041	393	4,054	7,097	1,392
Flex Admin/BTA	100125	Included in benefits rate	1	15	10		4	16	8	3		103	10	104	181	36
Executive Supplemental/COLI	100126	Retained At Corp														
Professional Accounting Fees	100127	Contract Specific & MMF		42	440							750	202	750	950	157
ASO Charges	100128	Included in benefits rate	5	24	38	-	16	-	-	11		298	38	387	184	133
Teach For America	100132	MMF														
Contributions, Tables, Multi-Years	100133	Retained At Corp														
Corporate Memberships	100134	MMF														
Public Relations - Employee Comm.	100135	% of Total Employees	0	6	5	-	1	-	-	35		313	3	29	78	9
Public Relations - Annual Report	100136	MMF														
Public Relations - Corp Communications	100137	MMF														
Matching Gifts	100138	Matching gifts						8	4			151		98	10	
Legal Library	100139	% DT Attorneys										146		73		
Executive Board Meeting Exp	100140	MMF														
Body Shop / Wellness	100141	% of DT Headcount	2	1	17	-	-	-	-	-		115	17	117		18
Employee Recreation	100142	% of DT Headcount	0	0	3	-	-	-	-	-		24	4	25		4
Fuji Lease	100143	Based on Sys depreciation before lease - BU														
International Graphics	100144	Direct Usage										1,147				72
Intl PR, Marketing, & Communications	100145	Direct Usage										1,793				
Conventions/Inauguration	100178	Retained At Corp														
Corporate Aircraft Usage	100207	MMF														
Support Services (Co 423 Charges)	100211	MMF														

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COST CENTER NAME/DESCRIPTION	SAP CC #	Assessment/Allocation Method	EEDC	CF - MTBE	Global Products	NBP Services	LRCO	HPLP	EPSC	Enron Europe	EI,	Consol	ECM	EES	PGE	ECI
SAP COE Control Group	100216	Determined by the Steering Com		60			20	130		1,500		1,500		800	1,500	800
HR & Community Relations - Executive	100218	MMF														
Accounts Payable - MSA/SAP	100220	Line Count		17			28	41						222		
Environment	100222	Anticipated Resources										760				
Environment Policy & Compliance	100223	Retained At Corp														
EARN Risk Management	100225	Anticipated Resources		84	7		6	11	18	104		440	2	64	27	9
EARN Executive	100227	Retained At Corp														
Accounts Payable - SUN System	100229	Direct support for EI only										764				
Vision & Values Task Force	100230	MMF														
International Government Affairs	100231	Usage										1,330				
International Regulatory Affairs	100232	Usage										2,273				
International Project Finance	100233	Usage								119		1,009				
Strategic Initiatives	100236	MMF														
SAP HR Project	100237	Retained At Corp														
MS Analysts Program	100238	Retained At Corp														
IT Communications & Market Data	100242	Usage	33	18	967		1	53	243	789		5,719	317	1,437	242	7
IT Infrastructure & Integration	100243	Usage	34	24	332		3	104	194	425		471	305	1,323	112	73
IT Corporate Applications Development	100244	Usage	1	10	5			11	6	43		1,691	214	260	129	9
EARN Origination	100245	Retained At Corp														
MD Recruiting & Resource Mgmt	100246	Retained At Corp														
Enron Technology Executive	100277	Retained At Corp														
Asset Ops - Development Support	100250	Direct Usage								159		1,111				
Asset Ops - Construction Support	100251	Direct Usage								382		742				
Asset Ops - EHS	100252	Direct Usage								285		2,312				
Asset Ops - Quality Management	100253	Direct Usage								507		2,171				
Asset Ops - Operations Support	100254	Direct Usage								453		3,777				
Insurance Premiums	100255	Past Usage	7	1,349	185		79	159	470	368		698	54	1,674	710	236
Sales & Use Tax	100280	Anticipated Resources														
Vice- Chairman (Sutton)	100281	MMF														
Accounts Payable - Executive	100801	Prorata to MSA/SAP & SUN support CC's		3			4	6				119		35		
Work Life	100805	% of DT Headcount	2	1	13	-	-	-	-	-		89	13	91	-	14
A&A Recruits Expenses	100806	Allocated based on Analyst & Assoc used														
A&A Recruiting	100807	Allocated based on Analyst & Assoc used														
A&A Training & Development	100808	Allocated based on Analyst & Assoc used														
A&A Operations	100809	Allocated based on Analyst & Assoc used														
A&A Exec & Strategic Planning & Dev	100810	Allocated based on Analyst & Assoc used														
SAP Costs Related to Project Apollo				70			30	170		2,000		2,000		900	2,000	900
GRAND TOTAL			393	3,228	3,362	149	647	2,339	1,855	17,941		113,220	3,596	85,753	20,339	79,008
Downtown			12	7	91							633	95	646		100
US			12	59	89		41			27		633	94	970	2,798	333
US & Expat			12	59	95		41			27		747	94	970	2,798	333
Total			13	222	178		43			1,308		11,661	96	1,080	2,926	353
Downtown			0.22%	0.13%	1.69%	0.00%	0.00%	0.00%	0.00%	0.00%		11.72%	1.76%	11.97%	0.00%	1.85%
US			0.11%	0.52%	0.79%	0.00%	0.36%	0.00%	0.00%	0.24%		5.62%	0.83%	8.61%	24.84%	2.96%
US & Expat			0.10%	0.52%	0.83%	0.00%	0.36%	0.00%	0.00%	0.24%		6.53%	0.82%	8.48%	24.45%	2.91%
Total			0.05%	0.81%	0.65%	0.00%	0.16%	0.00%	0.00%	4.79%		42.71%	0.35%	3.96%	10.72%	1.29%

Corporate Staff and Service Group Analysis
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COST CENTER NAME/DESCRIPTION	SAP CC #	Assessment/Allocation Method	CF- Mont Belvieu	EREC	Enron Wind	San Juan Gas	AZURIX	Global E&P	Subtotal	Enron Corp	Total
Benefits & Compensation	100001	% of Headcount	10	-	-	-	98	41	4,038	1,053	5,091
EMI Billing R/C (ECM)	100003	Retained At EMI							284		284
Deferral Plans	100005	Retained At Corp							-	10,434	10,434
Long Term Incentive	100007	Grant Elections							4,101	7,361	11,462
Drug/Alcohol Testing	100008	% of New Hires, Random	1				17		345	24	369
Executive Consultants	100009	Retained At Corp							-	1,568	1,568
IT - Corporate Executive	100010	% of service costs	1		2		42		2,298	298	2,596
EDS Corp Support Costs	100011	Retained At Corp							-	250	250
Corp Accounting, Planning, & Reporting	100012	MMF							25	3,783	3,808
HR Support Services	100013	% of Headcount	4	-		-	35	15	1,556	273	1,829
RAC - Engineering Group	100014	Anticipated Resources							2,814		2,814
Sr. VP - Chief Accounting Officer	100016	MMF							-	1,719	1,719
President and COO	100017	MMF							-	2,549	2,549
Vice Chairman	100018	MMF							-	194	194
Community Relations	100019	MMF							-	2,155	2,155
Executive Reception	100020	MMF							-	999	999
Political Action Committee	100021	MMF							-	186	186
Diversity	100022	MMF							-	515	515
Investor Relations	100024	MMF							50	2,310	2,360
State Tax Group	100026	State tax returns, anticipated resources		35			10		471	28	499
Vice President - Tax	100027	Anticipated Resources/MMF		80					80	6,825	6,905
Corporate Development	100028	Retained at Corp							-	3,382	3,382
Ad Valorem Tax	100029	Properties, Tax, & MMF			50				932	229	1,161
Corporate Secretary	100030	Anticipated Resources/Company Numbers		40			67		670	3,539	4,209
MLP Services	100031	MMF/MLP Direct							310	209	519
Credit Union	100032	Retained At Corp							-		-
H.R.I.S.	100033	% of Headcount	10	-	-	-	101	43	3,505	612	4,117
Health Center	100034	% of DT Headcount	1	-	-	-	29	9	548	170	718
Intellectual Capital	100035	Historical data & transaction count					85		1,220	266	1,486
Risk Mgmt - Research Group	100038	Historical data, groups supported							5,035	2,014	7,049
Legal - Litigations	100039	Usage				454			2,643	1,488	4,131
Corporate Legal	100040	Anticipated Resources					250		3,655	1,353	5,008
Environmental Legal	100041	Anticipated Resources				26			487	24	511
Federal Government Affairs	100042	Anticipated Resources					145		249	4,623	4,872
Chairman and CEO	100044	MMF							-	2,962	2,962
Tax - Analyst/Intern Recruiting	100045	Resources & Assignment					44		1,100	509	1,609
Public Relations - Advertising	100046	Retained At Corp							-	17,650	17,650
VP - HR Administration	100050	% of Headcount	3	-	-	-	31	13	1,383	243	1,626
IT Information Services	100051	Usage (phone lines, etc.)	4					434	12,504	474	12,978
RAC - Global Credit Group	100052	Anticipated Resources							2,519	189	2,708
RAC - Due Diligence/Asset Management	100053	Anticipated Resources							1,928		1,928
RAC - Risk Analytics	100054	Anticipated Resources		92			245		3,068		3,068
RAC Underwriting	100055	Anticipated Resources					112		2,249	-	2,249
Community Relations Programs	100056	% of DT Headcount	1	-	-	-	52	16	968	302	1,270
Staffing	100058	Anticipated Resources							1,708	1,820	3,528
Federal Regulatory Affairs	100059	Anticipated Resources							625		625
Env. & Intl Govt Affairs	100060	Anticipated Resources							981	247	1,228
Sr. VP - Governmental Affairs	100061	Retained At Corp							-	2,375	2,375
Electricity Regulatory Affairs	100062	Anticipated Resources					404		19,509		19,509
Vacant Space	100064	MMF							-	360	360
Houston Children's Chorus	100065	MMF							-	48	48
Management Conference	100066	% of Attendees	1	36			120		580	146	726
RAC Risk Management Control	100068	Historical data, groups supported							3,531		3,531
United Way Campaign	100069	Actuals, Estimate on 1999 Co Matching		191			85	50	1,688	472	2,160
Community Relations - Employee Events	100070	% of DT Headcount	0	-	-	-	20	6	384	119	503
Asset Operations	100071	Direct support							693		693
State Govt Affairs - TX,OK,AR,LA	100072	Anticipated Resources							420		420

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Corporate Staff and Service Group Analysis
Summary
2000 Operating Budgets
In thousands of dollars, except headcount

COST CENTER NAME/DESCRIPTION	SAP CC #	Assessment/Allocation Method	CF- Mont Belvieu	EREC	Enron Wind	San Juan Gas	AZURIX	Global E&P	Subtotal	Enron Corp	Total
Public Relations - Astros	100073	Agreed by Executive Com							1,075	2,225	3,300
International Benefits	100075	% of International Headcount						446	2,876		2,876
Best Buddies	100076	MMF							-	9	9
Organization Planning & Performance	100077	MMF							-	813	813
EMS Analysis Recruiting	100078	MMF/Prostaff Usage							652	983	1,635
SAP Implementation (Project Apollo)	100079	Retained at Corp							-	104	104
Corp Billing R/C (EOC/MSA & ECM)	100081	MMF & Retained At Corp							-	5,151	5,151
Savings Plan	100083	Included in benefits rate	33				498		19,258	2,777	22,035
State Govt Affairs - California/West	100085	Anticipated Resources							705		705
State Govt Affairs - Canada	100086	Anticipated Resources							516		516
State Govt Affairs - Mid Atl/NY/NE	100087	Anticipated Resources							825		825
State Govt Affairs - Midwest/Great Lakes	100088	Anticipated Resources							550		550
Corp IT Compliance & Systems Risk Mgmt	100091	Retained At Corp							-	1,097	1,097
Labor Relations Risk Management	100092	Anticipated Resources					9		215	74	289
Risk Management - Executive	100097	Usage							854	0	854
Gov't Affairs - Mexico	100100	Anticipated Resources							406		406
Public Relations - Internet Marketing	100102	MMF							-	880	880
IT - Technology Training	100103	Historical Usage					43		749	112	861
American Indian Affairs - Gov't Affairs	100105	Retained At Corp							-	3	3
Other G&A costs	100106	MMF							-	-	-
State Gov't / Fed Reg Env / Implementaion	100108	Anticipated Resources							350		350
Wind Down - Omaha	100109	Retained At Corp							-	12	12
Fair Employment Practices	100110	% of Headcount	1	7	22	-	13	5	530	141	671
1992 Deferral Plan	100111	Retained At Corp							-	119	119
Restricted Stock	100112	Grant Elections	15						62,275	15,834	78,109
NQ Stock Plan	100113	Awards grants	12					128	69,353	8,610	77,963
Annual Incentive	100114	Estimated payments / MMF (corp only)							82,298	18,066	100,364
Executive Perqs	100115	MMF							-	210	210
Employee Performance Award	100116	MMF							-	215	215
1994 Deferral Plan	100117	Retained At Corp							-	10,000	10,000
All Employee Stock Option Plan	100118	5% of est. payroll	56				853		29,461	3,648	33,109
Cash Balance/SERP	100119	Included in benefits rate					658		20,876	120	20,996
EE Life, AD&D	100120	Included in benefits rate	8				68		3,438	427	3,865
Long Term Disability	100121	Included in benefits rate	5				42		2,149	267	2,416
ESOP/Savings Plan Admin Fees	100122	Included in benefits rate	1				4		208	27	235
Inactive Medical FAS 106	100123	Included in benefits rate	19				329		15,038	965	16,003
Active Medical/Dental	100124	Included in benefits rate	92				736		37,393	4,643	42,036
Flex Admin/BTA	100125	Included in benefits rate	2				19		955	120	1,075
Executive Supplemental/COLI	100126	Retained At Corp							-		-
Professional Accounting Fees	100127	Contract Specific & MMF							8,226	3,305	11,531
ASO Charges	100128	Included in benefits rate	9	-	-	-	88	37	2,952	1,615	4,567
Teach For America	100132	MMF							-	52	52
Contributions, Tables, Multi-Years	100133	Retained At Corp							-	2,912	2,912
Corporate Memberships	100134	MMF							-	500	500
Public Relations - Employee Comm.	100135	% of Total Employees	1	-	21	-	64	2	689	43	732
Public Relations - Annual Report	100136	MMF							-	774	774
Public Relations - Corp Communications	100137	MMF							-	2,518	2,518
Matching Gifts	100138	Matching gifts		12	1		75		853	647	1,500
Legal Library	100139	% DT Attorneys					37		615	117	732
Executive Board Meeting Exp	100140	MMF							-	2,792	2,792
Body Shop / Wellness	100141	% of DT Headcount	1	-	-	-	40	12	747	232	979
Employee Recreation	100142	% of DT Headcount	0	-	-	-	8	3	158	49	207
Fuji Lease	100143	Based on Sys depreciation before lease - BU							2,531		2,531
International Graphics	100144	Direct Usage					143		1,434		1,434
Intl PR, Marketing, & Communications	100145	Direct Usage						65	1,956	1,304	3,260
Conventions/Inauguration	100178	Retained At Corp							-	1,463	1,463
Corporate Aircraft Usage	100207	MMF							-	6,484	6,484
Support Services (Co 423 Charges)	100211	MMF							-	134	134

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Corporate Staff and Service Group Analysis
Summary
2000 Operating Budgets
In thousands of dollars, except headcount

COST CENTER NAME/DESCRIPTION	SAP CC #	Assessment/Allocation Method	CF-Mont Belvieu	EREC	Enron Wind	San Juan Gas	AZURIX	Global E&P	Subtotal	Enron Corp	Total
SAP COE Control Group	100216	Determined by the Steering Com							10,300	1,717	12,017
HR & Community Relations - Executive	100218	MMF							-	546	546
Accounts Payable - MSA/SAP	100220	Line Count							1,429	410	1,839
Environment	100222	Anticipated Resources							760	329	1,089
Environment Policy & Compliance	100223	Retained At Corp							-	2,044	2,044
EARN Risk Management	100225	Anticipated Resources	5		25	348			2,141	106	2,247
EARN Executive	100227	Retained At Corp							-	3,694	3,694
Accounts Payable - SUN System	100229	Direct support for EI only							764		764
Vision & Values Task Force	100230	MMF							-	133	133
International Government Affairs	100231	Usage							1,330		1,330
International Regulatory Affairs	100232	Usage							2,273		2,273
International Project Finance	100233	Usage							1,128	57	1,185
Strategic Initiatives	100236	MMF							-	2,071	2,071
SAP HR Project	100237	Retained At Corp							-	-	-
MS Analysts Program	100238	Retained At Corp							-		-
IT Communications & Market Data	100242	Usage	13		12		779	350	21,967	3,130	25,097
IT Infrastructure & Integration	100243	Usage			17		180	25	10,548	2,576	13,124
IT Corporate Applications Development	100244	Usage			14		11	25	6,039	172	6,211
EARN Origination	100245	Retained At Corp							-	2,248	2,248
MD Recruiting & Resource Mgmt	100246	Retained At Corp							-	500	500
Enron Technology Executive	100277	Retained At Corp							-	2,666	2,666
Asset Ops - Development Support	100250	Direct Usage							1,588		1,588
Asset Ops - Construction Support	100251	Direct Usage							1,124		1,124
Asset Ops - EHS	100252	Direct Usage							2,854		2,854
Asset Ops - Quality Management	100253	Direct Usage							2,819		2,819
Asset Ops - Operations Support	100254	Direct Usage							5,036		5,036
Insurance Premiums	100255	Past Usage	136		789	2,687			27,426	2,225	29,651
Sales & Use Tax	100280	Anticipated Resources							480	19	499
Vice- Chairman (Sutton)	100281	MMF							-	2,783	2,783
Accounts Payable - Executive	100801	Prorata to MSA/SAP & SUN support CC's							345	64	409
Work Life	100805	% of DT Headcount	1	-	-	-	31	9	581	181	762
A&A Recruits Expenses	100806	Allocated based on Analyst & Assoc used							-	5,508	5,508
A&A Recruiting	100807	Allocated based on Analyst & Assoc used							-	1,581	1,581
A&A Training & Development	100808	Allocated based on Analyst & Assoc used							-	700	700
A&A Operations	100809	Allocated based on Analyst & Assoc used							-	1,624	1,624
A&A Exec & Strategic Planning & Dev	100810	Allocated based on Analyst & Assoc used							-	700	700
SAP Costs Related to Project Apollo									13,800	2,600	16,400
GRAND TOTAL			445	493	953	3,515	4,721	1,735	579,051	231,327	810,378
Downtown			5				220	66		1,282	5,399
US			22		374		220	66		1,328	11,265
US & Expat			22		381		220	93		1,328	11,444
Total			31		775		2,387	93		1,597	27,300
Downtown			0.09%	0.00%	0.00%	0.00%	4.07%	1.22%		23.75%	100.00%
US			0.20%	0.00%	3.32%	0.00%	1.95%	0.59%		11.79%	100.00%
US & Expat			0.19%	0.00%	3.33%	0.00%	1.92%	0.81%		11.60%	100.00%
Total			0.11%	0.00%	2.84%	0.00%	8.74%	0.34%		5.85%	100.00%

ENRON CORP

2000 PLAN

MMF Charges of Corporate & Other Expenses
In Thousands Of Dollars

Description	SAP COST CENTER	2000 Gross Expenses	Direct Charges In/(Out)	Corp Expenses Not MMF & Adjustments	Net Expenses For MMF	Corporate	Transwestern	Florida Gas	Portland General	Northern Plains	Northern Natural	Total Distribution
MMF % Per Operating Company - estimated 1999						57.10%	3.20%	3.60%	19.00%	6.30%	10.80%	100.00%
Benefits & Compensation	100001	5,091	(4,038)	(674)	379	216	12	14	72	24	41	379
EMI Billing R/C (ECM)	100003	284	(284)	-	-	-	-	-	-	-	-	-
Deferral Plans	100005	10,434	-	(10,434)	-	-	-	-	-	-	-	-
Long Term Incentive	100007	11,462	(4,101)	(6,000)	1,361	777	44	49	259	86	147	1,361
Drug/Alcohol Testing	100008	369	(345)	-	24	14	1	1	5	2	3	24
Executive Consultants	100009	1,568	-	(1,568)	-	-	-	-	-	-	-	-
IT - Corporate Executive	100010	2,596	(2,298)	(298)	-	-	-	-	-	-	-	-
EDS Corp Support Costs	100011	250	-	(250)	-	-	-	-	-	-	-	-
Corp Accounting, Planning, & Reporting	100012	3,808	(25)	(750)	3,033	1,732	97	109	576	191	328	3,033
HR Support Services	100013	1,829	(1,556)	(61)	212	121	7	8	40	13	23	212
RAC - Engineering Group	100014	2,814	(2,814)	-	-	-	-	-	-	-	-	-
Sr. VP - Chief Accounting Officer	100016	1,719	-	(900)	819	468	26	29	156	52	88	819
President and COO	100017	2,549	-	(2,549)	-	-	-	-	-	-	-	-
Vice Chairman	100018	194	-	(194)	-	-	-	-	-	-	-	-
Community Relations	100019	2,155	-	-	2,155	1,231	69	78	409	136	233	2,155
Executive Reception	100020	999	-	(500)	499	285	16	18	95	31	54	499
Political Action Committee	100021	186	-	(186)	-	-	-	-	-	-	-	-
Diversity	100022	515	-	-	515	294	16	19	98	32	56	515
Investor Relations	100024	2,360	(50)	-	2,310	1,319	74	83	439	146	249	2,310
State Tax Group	100026	499	(471)	-	28	16	1	1	5	2	3	28
Vice President - Tax	100027	6,905	(80)	(2,887)	3,938	2,249	126	142	748	248	425	3,938
Corporate Development	100028	3,382	-	(3,382)	-	-	-	-	-	-	-	-
Ad Valorem Tax	100029	1,161	(932)	-	229	131	7	8	44	14	25	229
Corporate Secretary	100030	4,209	(670)	(1,000)	2,539	1,450	81	91	482	160	274	2,539
MLP Services	100031	519	(310)	(209)	-	-	-	-	-	-	-	-
Credit Union	100032	-			-	-	-	-	-	-	-	-
H.R.I.S.	100033	4,116	(3,505)	-	611	349	20	22	116	38	66	611
Health Center	100034	718	(548)	-	170	97	5	6	32	11	18	170
Intellectual Capital	100035	1,486	(1,220)	(266)	-	-	-	-	-	-	-	-
Risk Mgmt - Research Group	100038	7,049	(5,035)	(2,014)	-	-	-	-	-	-	-	-
Legal - Litigations	100039	4,131	(2,643)	(1,488)	-	-	-	-	-	-	-	-
Corporate Legal	100040	5,008	(3,655)	(500)	853	487	27	31	162	54	92	853
Environmental Legal	100041	511	(487)	-	24	14	1	1	5	2	3	24
Federal Government Affairs	100042	4,872	(249)	(2,000)	2,623	1,498	84	94	498	165	283	2,623
Chairman and CEO	100044	2,962	-	-	2,962	1,691	95	107	563	187	320	2,962
Tax - Analyst/Intern Recruiting	100045	1,609	(1,100)	-	509	291	16	18	97	32	55	509
Public Relations - Advertising	100046	17,650	-	(17,650)	-	-	-	-	-	-	-	-
VP - HR Administration	100050	1,626	(1,383)	-	243	139	8	9	46	15	26	243
IT Ifnormation Services	100051	12,978	(12,504)	(474)	-	-	-	-	-	-	-	-
RAC - Global Credit Group	100052	2,708	(2,519)	-	189	108	6	7	36	12	20	189
RAC - Due Diligence/Asset Management	100053	1,928	(1,928)	-	-	-	-	-	-	-	-	-
RAC - Risk Analytics	100054	3,068	(3,068)	-	-	-	-	-	-	-	-	-
RAC Underwriting	100055	2,249	(2,249)	-	-	-	-	-	-	-	-	-
Community Relations Programs	100056	1,270	(968)	-	302	172	10	11	57	19	33	301
Staffing	100058	3,528	(1,708)	(500)	1,320	754	42	48	251	83	143	1,320
Federal Regulatory Affairs	100059	625	(625)	-	-	-	-	-	-	-	-	-
Env. & Intl Govt Affairs	100060	1,228	(981)	(247)	-	-	-	-	-	-	-	-
Sr. VP - Governmental Affairs	100061	2,375	-	(2,375)	-	-	-	-	-	-	-	-
Electricity Regulatory Affairs	100062	19,509	(19,509)	-	-	-	-	-	-	-	-	-
Vacant Space	100064	360	-	-	360	206	12	13	68	23	39	360
Houston Children's Chorus	100065	48	-	-	48	27	2	2	9	3	5	48
Management Conference	100066	726	(580)	-	146	83	5	5	28	9	16	146
RAC Risk Management Control	100068	3,531	(3,531)	-	-	-	-	-	-	-	-	-
United Way Campaign	100069	2,160	(1,688)	-	472	270	15	17	90	30	51	472
Community Relations - Employee Events	100070	503	(384)	-	119	68	4	4	23	8	13	120
Asset Operations	100071	693	(693)	-	-	-	-	-	-	-	-	-
State Govt Affairs - TX,OK,AR,LA	100072	420	(420)	-	-	-	-	-	-			

Corp. Allocations

ENRON CORP

2000 PLAN

MMF Charges of Corporate & Other Expenses
In Thousands Of Dollars

Description	SAP COST CENTER	2000 Gross Expenses	Direct Charges In/(Out)	Corp Expenses Not MMF & Adjustments	Net Expenses For MMF	Corporate	Transwestern	Florida Gas	Portland General	Northern Plains	Northern Natural	Total Distribution
Public Relations - Astros	100073	3,300	(1,075)	(2,225)	-	-	-	-	-	-	-	-
International Benefits	100075	2,876	(2,876)	-	-	-	-	-	-	-	-	-
Best Buddies	100076	9	-	-	9	5	0	0	2	1	1	9
Organization Planning & Performance	100077	813	-	(300)	513	293	16	18	97	32	55	513
EMS Analysts Recruiting	100078	1,635	(652)	(983)	-	-	-	-	-	-	-	-
SAP Implemenation (Project Apollo)	100079	104	-	(104)	-	-	-	-	-	-	-	-
Corp Billing R/C (EOC/MSA & ECM)	100081	5,151	-	(4,000)	1,151	657	37	41	219	73	124	1,151
Savings Plan	100083	22,035	(19,258)	(2,777)	-	-	-	-	-	-	-	-
State Govt Affairs - California/West	100085	705	(705)	-	-	-	-	-	-	-	-	-
State Govt Affairs - Canada	100086	516	(516)	-	-	-	-	-	-	-	-	-
State Govt Affairs - Mid Atl/NY/NE	100087	825	(825)	-	-	-	-	-	-	-	-	-
State Govt Affairs - Midwest/Great Lakes	100088	550	(550)	-	-	-	-	-	-	-	-	-
Corp IT Compliance & Systems Risk Mgmt	100091	1,097	-	(1,097)	-	-	-	-	-	-	-	-
Labor Relations Risk Management	100092	289	(215)	(2)	72	41	2	3	14	5	8	72
Risk Management - Executive	100097	854	(854)	-	0	0	-	-	-	0	0	0
Gov't Affairs - Mexico	100100	406	(406)	-	-	-	-	-	-	-	-	-
Public Relations - Internet Marketing	100102	880	-	(880)	-	-	-	-	-	-	-	-
IT - Technology Training	100103	861	(749)	-	112	64	4	4	21	7	12	112
American Indian Affairs - Gov't Affairs	100105	3	-	-	3	2	0	0	1	0	0	3
Other G&A costs	100106	-	-	-	-	-	-	-	-	-	-	-
State Gov't / Fed Reg Env / Implementaion	100108	350	(350)	-	-	-	-	-	-	-	-	-
Wind Down - Omaha	100109	12	-	-	12	7	0	0	2	1	1	12
Fair Employment Practices	100110	671	(530)	-	141	80	5	5	27	9	15	141
1992 Deferral Plan	100111	119	-	(119)	-	-	-	-	-	-	-	-
Restricted Stock	100112	78,109	(62,275)	(15,833)	1	1	0	0	-	0	0	1
NQ Stock Plan	100113	77,963	(69,353)	(8,610)	-	-	-	-	-	-	-	-
Annual Incentive	100114	100,364	(82,298)	(9,000)	9,066	5,177	290	326	1,723	571	979	9,066
Executive Perqs	100115	210	-	-	210	120	7	8	40	13	23	210
Employee Performance Award	100116	215	-	-	215	123	7	8	41	14	23	215
1994 Deferral Plan	100117	10,000	-	(10,000)	-	-	-	-	-	-	-	-
All Employee Stock Option Plan	100118	33,109	(29,461)	(3,648)	-	-	-	-	-	-	-	-
Cash Balance/SERP	100119	20,996	(20,876)	(120)	-	-	-	-	-	-	-	-
EE Life, AD&D	100120	3,865	(3,438)	(427)	-	-	-	-	-	-	-	-
Long Term Disability	100121	2,416	(2,149)	(267)	-	-	-	-	-	-	-	-
ESOP/Savings Plan Admin Fees	100122	235	(208)	(27)	-	-	-	-	-	-	-	-
Inactive Medical FAS 106	100123	16,003	(15,038)	(965)	-	-	-	-	-	-	-	-
Active Medical/Dental	100124	42,036	(37,393)	(4,643)	-	-	-	-	-	-	-	-
Flex Admin/BTA	100125	1,075	(955)	(120)	-	-	-	-	-	-	-	-
Executive Supplemental/COLI	100126	-	-	-	-	-	-	-	-	-	-	-
Professional Accounting Fees	100127	11,531	(8,226)	(1,700)	1,605	916	51	58	305	101	173	1,605
ASO Charges	100128	4,567	(2,952)	(1,615)	(0)	(0)	(0)	(0)	-	(0)	(0)	(0)
Teach For America	100132	52	-	-	52	30	2	2	10	3	6	52
Contributions, Tables, Multi-Years	100133	2,912	-	(2,912)	-	-	-	-	-	-	-	-
Corporate Memberships	100134	500	-	-	500	286	16	18	95	32	54	500
Public Relations - Employee Comm.	100135	732	(689)	-	43	24	1	2	8	3	5	43
Public Relations - Annual Report	100136	774	-	-	774	442	25	28	147	49	84	774
Public Relations - Corp Communications	100137	2,518	-	(750)	1,768	1,010	57	64	336	111	191	1,768
Matching Gifts	100138	1,500	(853)	-	647	369	21	23	123	41	70	647
Legal Library	100139	732	(615)	-	117	67	4	4	22	7	13	117
Executive Board Meeting Exp	100140	2,792	-	(1,125)	1,667	952	53	60	317	105	180	1,667
Body Shop / Wellness	100141	979	(747)	(232)	0	0	0	0	-	0	0	0
Employee Recreation	100142	207	(158)	(49)	0	0	-	0	-	0	0	0
Fuji Lease	100143	2,531	(2,531)	-	-	-	-	-	-	-	-	-
International Graphics	100144	1,434	(1,434)	-	-	-	-	-	-	-	-	-
Intl PR, Marketing, & Communications	100145	3,260	(1,956)	(1,304)	-	-	-	-	-	-	-	-
Conventions/Inauguration	100178	1,463	-	(1,463)	-	-	-	-	-	-	-	-
Corporate Aircraft Usage	100207	6,484	-	(5,000)	1,484	847	47	53	282	93	160	1,484
Support Services (Co 423 Charges)	100211	134	-	-	134	77	4	5	25	8	14	134
SAP COE Control Group	100216	12,017	(10,300)	-	1,717	980	55	62	326	108	185	1,717

ENRON CORP

2000 PLAN

MMF Charges of Corporate & Other Expenses
In Thousands Of Dollars

Description	SAP COST CENTER	2000 Gross Expenses	Direct Charges In/(Out)	Corp Expenses Not MMF & Adjustments	Net Expenses For MMF	Corporate	Transwestern	Florida Gas	Portland General	Northern Plains	Northern Natural	Total Distribution
HR & Community Relations - Executive	100218	546	-	-	546	312	17	20	104	34	59	546
Accounts Payable - MSA/SAP	100220	1,839	(1,429)	-	410	234	13	15	78	26	44	410
Environment	100222	1,089	(760)	(329)	-	-	-	-	-	-	-	-
Environment Policy & Compliance	100223	2,044	-	(2,044)	-	-	-	-	-	-	-	-
EARN Risk Management	100225	2,247	(2,141)	(108)	(2)	(1)	(0)	(0)	-	(0)	(0)	(2)
EARN Executive	100227	3,694	-	(3,694)	-	-	-	-	-	-	-	-
Accounts Payable - SUN System	100229	764	(764)	-	-	-	-	-	-	-	-	-
Vision & Values Task Force	100230	133	-	-	133	76	4	5	25	8	14	133
International Government Affairs	100231	1,330	(1,330)	-	-	-	-	-	-	-	-	-
International Regulatory Affairs	100232	2,273	(2,273)	-	-	-	-	-	-	-	-	-
International Project Finance	100233	1,185	(1,128)	(57)	-	-	-	-	-	-	-	-
Strategic Initiatives	100236	2,071	-	(2,071)	-	-	-	-	-	-	-	-
SAP HR Project	100237	-	-	-	-	-	-	-	-	-	-	-
MS Analysts Program	100238	-	-	-	-	-	-	-	-	-	-	-
IT Communications & Market Data	100242	25,097	(21,967)	(3,130)	-	-	-	-	-	-	-	-
IT Infrastructure & Integration	100243	13,124	(10,548)	(2,576)	-	-	-	-	-	-	-	-
IT Corporate Applications Development	100244	6,211	(6,039)	(172)	-	-	-	-	-	-	-	-
EARN Origination	100245	2,248	-	(2,248)	-	-	-	-	-	-	-	-
MD Recruiting	100246	500	-	(500)	-	-	-	-	-	-	-	-
Enron Technology Executive	100277	2,666	-	(2,666)	-	-	-	-	-	-	-	-
Asset Ops - Development Support	100250	1,588	(1,588)	-	-	-	-	-	-	-	-	-
Asset Ops - Construction Support	100251	1,124	(1,124)	-	-	-	-	-	-	-	-	-
Asset Ops - EHS	100252	2,854	(2,854)	-	-	-	-	-	-	-	-	-
Asset Ops - Quality Management	100253	2,819	(2,819)	-	-	-	-	-	-	-	-	-
Asset Ops - Operations Support	100254	5,036	(5,036)	-	-	-	-	-	-	-	-	-
Insurance Premiums	100255	29,651	(27,426)	-	2,225	1,270	71	80	423	140	240	2,225
Sales & Use Tax	100280	499	(480)	-	19	11	1	1	4	1	2	19
Vice- Chairman (Sutton)	100281	2,783	-	(500)	2,283	1,304	73	82	434	144	247	2,283
Accounts Payable - Executive	100801	409	(345)	-	64	37	2	2	12	4	7	64
Work Life	100805	762	(581)	-	181	103	6	7	34	11	20	181
A&A Recruits Expenses	100806	5,508	-	(5,508)	-	-	-	-	-	-	-	-
A&A Recruiting	100807	1,581	-	(1,581)	-	-	-	-	-	-	-	-
A&A Training & Development	100808	700	-	(700)	-	-	-	-	-	-	-	-
A&A Operations	100809	1,624	-	(1,624)	-	-	-	-	-	-	-	-
A&A Exec & Strategic Planning & Dev	100810	700	-	(700)	-	-	-	-	-	-	-	-
SAP Costs Related to Project Apollo		16,400	(13,800)	-	2,600	1,485	83	94	494	164	281	2,600
TOTAL		810,377	(579,051)	(171,861)	59,465	33,954	1,903	2,141	11,300	3,746	6,422	59,466

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Services Charged Directly - Table for Testimony

Enron Service	1999 Actual	2002 Test Year	Testimony Cross Reference
Benefits & Compensation- Q	$ 324,996	$ 997,270	
Long Term Incentive- PGE	$ 164,037	$ 200,082	
HR Support Services	$ 200,004	$ 468,256	
HRIS	$ -	$ 157,133	
VP- HR Administration	$ -	$ 416,925	
Staffing	$ 15,300	$ -	
Savings Plan (billed on actuals)	$ -	$ 5,516,000	
Fair Employment and Practices	$ -	$ 98,470	
Restricted Stock	$ 57,822	$ 785,664	
NQ Stock Plan	$ 95,707	$ 483,131	
All Employee Stock Option Program	$ 4,301,618	$ 5,952,000	
EE Life, AD&D	$ -	$ 805,356	
Long Term Disability	$ -	$ 503,356	
Active Medical/Dental	$ -	$ 8,758,288	
Flex Admin/BTA	$ -	$ 190,112	
ASO Charges	$ -	$ 187,868	
Benefits & Compensation- W	$ 225,000	$ -	
Payroll Taxes	$ -	$ -	
HR Services (including Benefits)	$ 5,384,484	$ 25,519,911	
IT- Corporate Executive	$ 354,939	$ 23,046	
IT Information Services	$ -	$ 11,669	
SAP COE Control Group	$ -	$ 1,571,328	
IT Communications & Market Data	$ -	$ 253,508	
IT Infrastructure & Integration	$ -	$ 117,326	
IT Corporate Applications Development	$ -	$ 135,134	
Telecomm/Data Comm Ops	$ -	$ -	
Computer Services	$ -	$ -	
SAP Costs- Project Apollo	$ 2,700,000	$ 1,463,105	
IT Services (including SAP)	$ 3,054,939	$ 3,575,116	
Corporate Secretary	$ 12,588	$ 13,618	
Corporate Legal	$ 192,277	$ -	
Enrvironmental Legal	$ -	$ 53,425	
Legal Services	$ 204,865	$ 67,043	
Risk Mgmt- Research Group	$ -	$ 20,951	
RAC- Global Credit Group	$ -	$ 28,284	
RAC- Due Dilligence	$ -	$ 60,758	
RAC- Risk Analytics	$ -	$ 192,750	
RAC- Risk Mgmt Control	$ -	$ 36,664	
Labor Relations Risk Management	$ 94,920	$ -	
EARN Risk Management	$ -	$ 25,000	
Risk Management	$ 18,996	$ -	
Risk Management Services	$ 113,916	$ 364,407	
State Tax Group	$ 45,863	$ 52,378	
Professional Accounting Fees	$ 900,000	$ 1,005,650	
Accounting/Tax Services	$ 945,863	$ 1,058,028	
Intellectual Capital	$ 27,000	$ 16,761	
Management Conference	$ -	$ 18,856	
Employee Communications	$ 83,208	$ 81,709	
ECM - Insurance Premiums	$ 568,862	$ 791,526	
Drug Control	$ -	$ -	
Aviation- Direct	$ 326,852	$ -	
EPSC	$ 17,965	$ -	
ECM (MMF)	$ 224,340	$ -	
Rent	$ -	$ -	
Miscellaneous Services	$ 1,248,227	$ 908,852	
Total Direct Services	**$ 10,952,294**	**$ 31,493,357**	
Check Total	$ -		

Services Charged Through MMF - Table for Testimony

Enron Service	1999 Actual	2002 Test Year	Testimony Cross Reference
HR Services (including Benefits)	$ 3,606,338	$ 3,056,757	
Corporate Communications Services	$ 567,270	$ 587,677	
Investor Relations Services	$ 454,014	$ 1,306,297	
Finance & Accounting Services	$ 1,856,008	$ 3,039,996	
Legal & Regulatory Services	$ 1,341,252	$ 702,907	
Miscellaneous Services	$ -	$ 540,537	
Executive Services	$ 3,208,344	$ 1,402,672	
Total Indirect Services	**$ 11,033,226**	**$ 10,636,843**	
Check total	$ -	$ -	

MODIFIED MASSACHUSETTS FORMULA CALCULATION
AS OF12/31/98, Except Gross PP&E Updated to 9/30/99
REVISED FOR EOG RESOURCES SPLIT 8/16/99

3/25/98
11:07 AM

CO. #	GROSS PLANT, PROPERTY & EQUIPMENT 09/30/1999	INVEST & EQTY EARNINGS OF UNCON SUBS 12/31/1998	%	GROSS MARGINS 12 MOS ENDED 12/31/1998	%	ACTUAL PAYROLL 12/31/1998	%	MMF
PGE	3,302,376,652	68,057,692	18.6%	722,757,279	16.2%	160,322,046	22.3%	19.0%
Enron Total	15,019,541,052	3,120,339,149	100.0%	4,448,477,804	100.0%	720,355,067	100.0%	100.0%

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2001 COMPARED TO 2002 FOM MODEL
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R/C=191-Pres/COO PGE Distribution Ops

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44013	49	191	REALC	.	.	.
181	N44013	69	191	REALC	$18,414	$18,856	$442
RCNAME					$18,414	$18,856	$442

R/C=273-Financial Accounting & Reporti

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44163	49	273	REALC	.	.	.
181	N44163	69	273	REALC	$933,999	$956,415	$22,416
911	N44163	49	273	REALC	.	.	.
911	N44163	69	273	REALC	$26,598	$27,236	$638
921	N44163	49	273	REALC	.	.	.
921	N44163	69	273	REALC	$21,483	$21,999	$516
RCNAME					$982,080	$1,005,650	$23,570

R/C=282-Corporate Tax

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44227	49	282	REALC	.	.	.
181	N44227	69	282	REALC	$51,150	$52,378	$1,228
RCNAME					$51,150	$52,378	$1,228

R/C=675-Risk Mgmt Reporting & Control

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N25603	69	675	REALC	$35,805	$36,664	$859
181	N44227	49	675	REALC	.	.	.
RCNAME					$35,805	$36,664	$859

R/C=682-Insurance & Claim Management

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	C82011	49	682	REALC	.	.	.
181	C82011	69	682	REALC	$720,030	$755,600	$35,570
181	N44411	49	682	REALC	.	.	.

2001 COMPARED TO 2002 FOM MODEL
FOR ENRON ALLOCATIONS

R/C=682-Insurance & Claim Management
(continued)

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44411	69	682	REALC	$20,160	$21,000	$840
911	C82011	49	682	REALC	.	.	.
911	C82011	69	682	REALC	$14,617	$15,339	$722
911	N44411	69	682	REALC	$2,880	$3,000	$120
921	C82011	49	682	REALC	.	.	.
921	C82011	69	682	REALC	$19,618	$20,587	$969
921	N44411	69	682	REALC	$960	$1,000	$40
RCNAME					$778,265	$816,526	$38,261

R/C=685-Finance

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44227	49	685	REALC	.	.	.
181	N44227	69	685	REALC	$27,621	$28,284	$663
RCNAME					$27,621	$28,284	$663

R/C=735-Information Technology

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44227	49	735	REALC	.	.	.
181	N44227	69	735	REALC	$528,010	$540,683	$12,673
RCNAME					$528,010	$540,683	$12,673

R/C=761-Financial Analysis

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44227	49	761	REALC	.	.	.
181	N44227	69	761	REALC	$208,692	$213,701	$5,009
RCNAME					$208,692	$213,701	$5,009

R/C=802-HR Operations

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44227	49	802	REALC	.	.	.

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R/C=802-HR Operations
(continued)

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44227	69	802	REALC	$96,162	$98,470	$2,308
RCNAME					$96,162	$98,470	$2,308

R/C=803-HR Administration

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44227	49	803	REALC	.	.	.
181	N44227	69	803	REALC	$610,731	$625,389	$14,658
RCNAME					$610,731	$625,389	$14,658

R/C=806-PGE Benefit Programs

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44201	49	806	REALC	$973,896	$997,270	$23,374
181	N44205	69	806	REALC	$195,393	$200,082	$4,689
181	N44206	69	806	REALC	$471,808	$483,131	$11,323
181	N44207	49	806	REALC	$767,250	$785,664	$18,414
181	N44452	49	806	ROMAT	$5,305,000	$5,516,000	$211,000
181	N44456	49	806	RMEDN	$9,770,000	$10,067,000	$297,000
~~181~~	~~N44456~~	~~69~~	~~806~~	~~RMEDN~~	~~$240,000~~	~~$325,000~~	~~$85,000~~
181	N44461	49	806	REALC	$5,731,000	$5,952,000	$221,000
181	N44491	49	806	REALC	$369,121	$377,980	$8,859
RCNAME					$23,823,468	$24,704,127	$880,659

R/C=809-VP Human Resources

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44227	49	809	REALC	.	.	.
181	N44227	69	809	REALC	$407,154	$416,925	$9,771
RCNAME					$407,154	$416,925	$9,771

2001 COMPARED TO 2002 FOM MODEL
FOR ENRON ALLOCATIONS

R/C=826-Org Trng & Dev Resources

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44227	49	826	REALC	.	.	.
181	N44227	69	826	REALC	$16,368	$16,761	$393
RCNAME					$16,368	$16,761	$393

R/C=891-SVP & General Counsel

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44227	49	891	REALC	.	.	.
181	N44227	49	891	RERAC	.	.	.
181	N44227	69	891	REALC	$13,299	$13,618	$319
181	N44227	69	891	RERAC	$59,334	$60,758	$1,424
RCNAME					$72,633	$74,376	$1,743

R/C=894-Legal Department

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44325	49	894	REALC	.	.	.
181	N44325	69	894	REALC	$52,173	$53,425	$1,252
RCNAME					$52,173	$53,425	$1,252

R/C=915-Public Relations

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44227	49	915	REALC	.	.	.
181	N44227	69	915	REALC	$79,794	$81,709	$1,915
RCNAME					$79,794	$81,709	$1,915

R/C=998-ENRON Corp Overheads

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44227	49	998	REALC	.	.	.
181	N44227	49	998	RECOE	.	.	.
181	N44227	49	998	RESAP	.	.	.

2001 COMPARED TO 2002 FOM MODEL
FOR ENRON ALLOCATIONS

R/C=998-ENRON Corp Overheads
(continued)

ENT	LEDGER	CE	RC	JOB	2001 FOM	2002 FOM	CHANGE
181	N44227	69	998	REALC	$11,559,900	$11,837,338	$277,438
181	N44227	69	998	RESAP	$2,963,314	$3,034,433	$71,119
RCNAME					$14,523,214	$14,871,771	$348,557
					$42,311,734	$43,655,695	$1,343,961
					- 240,000	- 325,000	
					42,071,734	43,330,695	

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MEDICAL PLAN ESTIMATES

PLAN		2001 Premium	2002 Premium	2001 Co. Cont.	2002 Co.Cont.	2001 # of Ees.	2002 # of Ees.	2001 Budget	2002 Budget
Kaiser	Ee. Only	$222.43	$244.67	$212.00	$234.00	149	148	$379,056.00	$415,584.00
Kaiser	Ee. + One	$411.49	$452.63	$393.00	$432.00	150	148	$707,400.00	$767,232.00
Kaiser	Ee. + Family	$533.82	$587.20	$510.00	$510.00	150	149	$918,000.00	$911,880.00
GH	Ee. Only	$249.76	$274.74	$212.00	$234.00	247	245	$628,368.00	$687,960.00
GH	Ee. + One	$462.06	$508.27	$393.00	$432.00	248	245	$1,169,568.00	$1,270,080.00
GH	Ee. + Family	$599.42	$659.37	$510.00	$510.00	248	246	$1,517,760.00	$1,505,520.00
HMOOR	Ee. Only	$252.30	$277.53	$212.00	$234.00	254	251	$646,176.00	$704,808.00
HMOOR	Ee. + One	$466.77	$513.45	$393.00	$432.00	254	252	$1,197,864.00	$1,306,368.00
HMOOR	Ee. + Family	$605.53	$666.08	$510.00	$510.00	254	252	$1,554,480.00	$1,542,240.00
TOTALS								$8,718,672.00	$9,111,672.00

ASSUMPTIONS:

9% premium esculation in 2001
10% premium esculation in 2002
Co. contribution remains approx. 85% of GH premium
1/3 of FTE's in each coverage category
Percentage of ees in each plan same as 2000

PGE
2001 Budget
401K Match

	Base Pay		Match	%
Company Match				
Non union	43,315,361	68%	1,070,749	2.47%
Union A	11,123,482	17%	619,361	5.57%
Union B	9,550,064	15%	336,174	3.52%
Thru May	63,988,907	100%	2,026,285	3.17%
Annual	153,573,377			
5% Contribution				
Union B	9,550,064		481,215	5.04%

If there are 1029 union employees now, and there will be 135 fewer in 2001and 2002, then union base pay and match will decline 13.12% to 894 union employees.

If the split is generic there will be (11,123,482/20,673,546)*894 or 481 Union A employees, and there will be (9,550,064/20,673,546)*894 or 413 Union B employees.
There are 2,848 FTE's budgeted in 2001 and 2,830 budgeted in 2002.

	Employees	Spread	Budget Labor 2001	%	
Company Match 2001					
Non union	1,954	69%	115,654,501	2.47%	2,858,962
Union A	481	17%	28,469,711	5.57%	1,585,209
Union B	413	15%	24,444,887	3.52%	860,490
Total	2,848	100%	168,569,098	3.17%	5,304,660
5% Contribution					
Union B			24,444,887	5.00%	1,222,244

	Employees	Spread	Budget Labor 2002	%	
Company Match 2002					
Non union	1,936	68%	119,751,508	2.47%	2,960,239
Union A	481	17%	29,752,312	5.57%	1,656,625
Union B	413	15%	25,546,164	3.52%	899,256
Total	2,830	100%	175,049,983	3.17%	5,516,120
5% Contribution					
Union B			25,546,164	5.00%	1,277,308

BENEFIT	2000	2001	2002
Long Term Disability*	$1,361,000	$1,497,000	$1,462,000
Active Life Ins. (Union)*	306,000	318,000	333,000
	287,000	298,000	312,000
	593,000	616,000	645,000
Active Life Ins. (Nonunion)*	332,000	344,000	356,000

* Estimates provided by Towers Perrin

Enron Allocations
Explanation of 2001 2002 Non-Inflation Calculations

Enron Allocations Variance Comments

Description	Methodology
Savings Plan (401k Match)	Budgeted labor x current savings rate for Nonunion and Union employees.
All Employee Stock Option Program	5% of budgeted non-union labor (CE 11) for each year.
EE Life, AD&D Long Term Disability Active Medical/Dental	The total of these three allocations is equal to $5,000 x budgeted FTEs (non-union) for 2001 and $5,200 for 2002. This amount is set by Enron.
EARN Risk Management ECM - Insurance Premiums	Amounts provided by Enron in September 1999. Copies of documentation provided by Jill Sughrue, 464-8908.

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2000 - 2002 FTE/LABOR COMPARISON
BY VP
STRAIGHT TIME LABOR Escalated

COST ELEMENT=11

VP	2000 FTE	2001 FTE	FTE CHANGE	2002 FTE	2000 BUDGET	2001 BUDGET	BUDGET CHANGE	2002 BUDGET
A. ALEXANDERSON	2	2	-0	2	269,475	284,298	14,823	299,910
A. N. BARNETT	88	92	4	89	5,305,935	5,828,789	522,854	6,037,850
C. B. TALTON	15	15	-0	15	1,026,690	1,045,957	19,267	1,104,040
C. D. RYDER	441	491	50	480	18,553,367	21,834,950	3,281,583	21,872,835
D. K. CARBONEAU	79	116	37	117	5,113,355	8,178,743	3,065,388	8,598,716
F. D. MILLER	360	372	12	377	23,257,836	24,646,623	1,388,787	26,067,535
J. A. MCARTHUR	972	976	4	980	52,975,068	54,803,996	1,828,928	57,645,443
J. J. PIRO	2	2	0	2	212,793	212,728	-65	225,331
M. K. TURINA	102	100	-1	104	6,291,721	6,445,059	153,338	6,796,092
P. G. LESH	27	27	0	27	1,767,537	1,799,997	32,460	1,899,683
P. Y. FOWLER	2	2	1	2	330,346	443,031	112,685	469,496
R. W. JOHNSON	24	22	-2	22	1,703,827	1,642,230	-61,597	1,732,407
S. R. HAWKE	96	100	4	100	6,960,532	7,499,688	539,156	7,897,720
W. E. POLLOCK	644	531	-114	513	38,728,309	33,903,009	-4,825,300	34,402,925
COST_ELM	2,854	2,848 –	-5	2,830 ~	162,496,791	168,569,098	6,072,307	175,049,983
	Union	894		894		6%		5%
		1,954		1,936		8,428,454		8,752,499
		× 5,000		× 5200		68%		68%
		9,770,000		10,067,000		5,731,349		5,951,677

Medical

AESOP

Sum 01:
LTD
EE life/AD&D
Active Medical/Dental

2001	2002
488,506	$503,356
781,595	805,356
8,499,899	8,758,288
9,770,000	10,067,000

Fr. Chick Mengis 6/12/00

2000 - 2002 OPERATING & STRATEGIC PLAN

Summary Of Insurance Costs
(Thousands of Dollars)

~~Corp.~~ Allocations
Workpapers ~~/ 32~~

UM-1121/PGE EXHIBIT/ 203
TINKER-MURRAY-HAGER/ 53

RC #	Description	1999 Plan	1999 Estimate	Operating & Strategic Plan 2000	2001	2002
2411	Insurance Premiums	$33,003.5	$27,490.6	$29,650.7	$30,832.7	$32,374.4

Distribution of Costs by Company

Company Name	1999 Plan	1999 Estimate	Operating & Strategic Plan 2000	2001	2002
CORPORATE					
Corporate Staff	$1,314.9	$1,314.9	$2,193.7	$2,343.6	$2,460.8
Enron Management Inc.	$24.8	$24.8	$30.7	$84.4	$88.6
Enron Property & Services	$440.0	$440.0	$470.0	$493.5	$518.2
ECM	$116.2	$116.2	$54.5	$109.2	$114.7
ECT	$4,242.7	$4,242.7	$3,937.7	$4,246.9	$4,459.3
ECT EUROPE	$495.4	$495.4	$367.8	$437.9	$459.7
GLOBAL PRODUCTS	$0.0	$0.0	$185.0	$234.6	$246.3
EEDC	$0.0	$0.0	$7.0	$58.8	$61.7
ECI	$141.3	$141.3	$236.1	$287.7	$302.1
GPG					
Northern Natural Gas	$4,787.7	$4,787.7	$5,304.5	$5,630.4	$5,911.9
Transwestern	$997.5	$997.5	$1,792.2	$1,961.3	$2,059.4
Citrus	$0.0	$0.0	$20.3	$61.8	$64.9
Florida Gas Transmission	$1,113.5	$1,113.5	$4,508.2	$5,018.6	$5,269.5
FGT Phase III	$182.2	$182.2	$261.2	$314.5	$330.2
HPL - Plant Ops.	$1.9	$1.9	$0.0	$0.0	$0.0
HPL - Pipeline Ops.	$103.9	$103.9	$158.6	$166.5	$174.9
Louisiana Resources Inc.	$52.4	$52.4	$78.9	$83.0	$87.1
Northern Plains Natural Gas	$8.3	$8.3	$8.0	$8.3	$8.7
GPG Executive	$148.8	$148.8	$160.6	$208.8	$219.3
Mont Belvieu Storage	$12.4	$12.4	$135.8	$182.8	$191.9
EGP Fuels - MTBE	$2,035.0	$2,035.0	$1,349.4	$1,457.1	$1,529.9
Methanol	$362.8	$362.8	$482.9	$547.3	$574.6
EOTT	$98.3	$98.3	$438.5	$460.4	$483.4
EI					
Consolidated	$524.2	$524.2	$696.2	$771.2	$809.8
Puerto Rico	$3,012.2	$3,012.2	$2,687.0	$1,009.1	$1,059.5
NEPCO	$258.3	$258.3	$352.7	$410.7	$431.2
TDEC	$0.0	$0.0	$8.1	$48.7	$51.2
EECC	$353.5	$353.5	$559.7	$695.6	$730.4
EES	$1,012.7	$1,012.7	$1,395.9	$1,505.9	$1,581.2
Enron Wind Corp	$960.5	$960.5	$789.4	$869.1	$912.5
PGE Total Premiums	$568.8	$568.8	$679.5 x1.11=	$753.8 x 1.05=	$791.5
PORTLAND GEN. HOLDINGS	$4.5	$4.5	$3.5	$43.9	$46.1
PORTLAND GEN. OPERATIONS	$5.9	$5.9	$27.0	$43.9	$46.1
EOG	$3,838.9	$3,838.9	$0.0	$0.0	$0.0
EREC	$1.1	$1.1	$0.0	$0.0	$0.0
LIMBACH HOLDINGS, INC.	$5,782.9	$270.0	$270.0	$283.5	$297.7
TOTAL	$33,003.5	$27,490.6	$29,650.7	$30,832.7	$32,374.4

01-Sept-99

RISK MANAGEMENT DEPARTMENT - #410
2000 - 2002 OPERATING & STRATEGIC PLAN
Departmental Expenses Summary for Executive Review
(In Thousands of Dollars)

	1999 Plan	1999 Estimate	Operating & Strategic Plan 2000	2001	2002
Gross Expense	$2,074	$2,074	$2,235	$2,290	$2,377
Distribution of Costs by Company					
CORPORATE					
Corporate Staff	39	39	83	84	88
Enron Management, Inc.	0	0	1	3	3
Enron Property & Services	0	0	18	18	19
ECM	4	4	2	15	16
ECT	161	161	177	200	210
ECT EUROPE	106	106	104	109	114
GLOBAL PRODUCTS	0	0	7	7	8
EEDC	0	0	0	0	0
ECI	4	4	9	10	11
GPG					
Northern Natural Gas	195	195	230	252	260
Transwestern	36	36	93	113	119
Citrus	0	0	1	1	1
Florida Gas Transmission	40	40	421	582	590
FGT Phase III	6	6	10	11	12
HPL - Plant Ops.	0	0	0	0	0
HPL - Pipeline Ops.	5	5	11	14	15
Louisiana Resources Inc.	3	3	6	6	6
Northern Plains	0	0	0	0	0
GPG Executive	4	4	6	6	7
Mont Belvieu Storage	0	0	5	5	6
EGP Fuels - MTBE	282	282	84	109	114
Methanol	26	26	30	39	41
EOTT	3	3	0	0	0
EI					
Consolidated	407	407	440	462	484
Puerto Rico	226	226	348	72	76
NEPCO	2	2	9	15	16
TDEC	0	0	0	0	0
EECC	0	0	13	22	23
EES	33	33	54	56	59
Enron Wind Corp	33	33	36	41	43
PGE	19	19	26	24	25
PORTLAND GEN. HOLDINGS	0	0	0	0	0
PORTLAND GEN. OPERATIONS	0	0	1	1	1
EOG	340	340	0	0	0
EREC	0	0	0	0	0
LIMBACH HOLDINGS, INC.	100	100	10	11	11
	2,074	2,074	2,235	2,290	2,377

Estimated Direct Charges from Enron For PGE Benefit Programs

2001 / 2002 Budgets for these items based on Calculations below, not 2000 Budget Escalated

2001 Expected Charges:		How Estimated
All Employee Stcok Ownership Plan:	5,731,349	Straight-time Wages * 5% (Value of Options received) * 68% (Estimated Non-Union Share of Wages)
Retirement Savings Plan:	5,304,660	Straight-time Wages * 3.15% (Avg. Company Match %)
Long-Term Disability:	488,506	Total for these 3 items is Estimated Non-Union FTE's * $5,000 per FTE
EE Life / AD&D:	781,595	Total for these 3 items is Estimated Non-Union FTE's * $5,000 per FTE
Medical / Dental:	8,499,899	Total for these 3 items is Estimated Non-Union FTE's * $5,000 per FTE
Total for these programs:	20,806,010	Flex Program calc: 9,770,000 = 1,954 FTEs * $5,000/FTE
		Sum of three programs: 9,770,000 Sum of LTD, EE Life/AD&D, Medical/Dental

2002 Expected Charges:		
All Employee Stcok Ownership Plan:	5,951,699	Straight-time Wages * 5% (Value of Options received) * 68% (Estimated Non-Union Share of Wages)
Retirement Savings Plan:	5,516,121	Straight-time Wages * 3.15% (Avg. Company Match %)
Long-Term Disability:	503,356	Total for these 3 items is Estimated Non-Union FTE's * $5,200 per FTE
EE Life / AD&D:	805,356	Total for these 3 items is Estimated Non-Union FTE's * $5,200 per FTE
Medical / Dental:	8,758,288	Total for these 3 items is Estimated Non-Union FTE's * $5,200 per FTE
Total for these programs:	21,534,820	Flex Program calc: 10,067,200 = 1,936 FTEs * $5,200/FTE
		Sum of three programs: 10,067,000 Sum of LTD, EE Life/AD&D, Medical/Dental

Correction to 2000 Budget Enron Allocations / Direct Charges

	As Filed DR#7 UM-967	Corrected	Diff.	Explanation
Allocations via MMF method	**11,300,000**	**11,300,000**	-	
Direct Charges:				
Benefits & Compensation- Q	952,000	952,000	-	
Long Term Incentive- PGE	191,000	191,000	-	
IT- Corporate Executive	22,000	22,000	-	
HR Support Services	447,000	447,000	-	
State Tax Group	50,000	50,000	-	
Corporate Secretary	13,000	13,000	-	
HRIS	150,000	150,000	-	
Intellectual Capital	16,000	16,000	-	
Risk Mgmt- Research Group	20,000	20,000	-	
Enrvironmental Legal	51,000	51,000	-	
VP- HR Administration	398,000	398,000	-	
IT Information Services	11,000	11,139	139	Rounding
RAC- Global Credit Group	27,000	27,000	-	
RAC- Due Dilligence	58,000	58,000	-	
RAC- Risk Analytics	184,000	184,000	-	
Management Conference	18,000	18,000	-	
RAC- Risk Mgmt Control	35,000	35,000	-	
Savings Plan (billed on actuals)	3,995,000	4,738,171	743,171	PGE updated based on expected charge
Fair Employment and Practices	94,000	94,000	-	
Restricted Stock	323,000	750,000	427,000	PGE updated based on expected charge
NQ Stock Plan	461,000	461,200	200	Rounding
All Employee Stock Option Program	4,087,147	4,087,000	(147)	Rounding
EE Life, AD&D	633,794	634,000	206	Rounding
Long Term Disability	396,000	396,000	-	
Active Medical/Dental	6,888,265	6,890,000	1,735	Rounding
Flex Admin/BTA	181,000	181,482	482	PGE updated based on expected charge
Professional Accounting Fees	950,000	960,000	10,000	PGE updated based on expected charge
ASO Charges	184,000	179,340	(4,660)	PGE updated based on expected charge
Employee Communications	78,000	78,000	-	
SAP COE Control Group	1,500,000	1,500,000	-	
EARN Risk Management	26,000	26,000	-	
IT Communications & Market Data	242,000	242,000	-	
IT Infrastructure & Integration	112,000	112,000	-	
IT Corporate Applications Development	129,000	129,000	-	
ECM - Insurance Premiums	680,000	679,518	(482)	Rounding
SAP Costs- Project Apollo	2,000,000	1,396,690	(603,310)	PGE updated based on expected charge
Sub-Total of Direct Charges	**25,603,206**	**26,177,540**	**574,334**	
Grand Total	**36,903,206**	**37,477,540**	**574,334**	

```
GL671B              Display Journals by Account Number                 GL670
Acct: 181-N44013-49-191-REALC                              Type: 4  Status: A
Desc: EXECUTIVE SUPPORT FOR AFFILIATES                Fiscal set: A  Year   : 1999
Currency: USD    Curn type: S    DR/CR Code:                         More   :

View totals N  (Y or N)                          Net change:                 0.00

Per/Yr  Journal         Amount      JOURNAL DESCRIPTION
12/1999 JSB27J          326,852.24- REVERSE THE EC CHARGE FOR EXCUTIVE LABOR
12/1999 JSB27J          326,852.24  ACCRUE LABOR CHARGE FOR BRAD ALFORD BILL
                              0.00
                              0.00
                              0.00
                              0.00
                              0.00
                              0.00
                              0.00
                              0.00
                              0.00
                              0.00
 COMMAND  . . INQ
LAST PAGE FOR PERIOD 12 DISPLAY
ENTER F1=HELP F3=EXIT F4=PROMPT F10=CUT F11=PASTE F13=INF F14=INQ F16=MARK
F20=FWD F21=PREV F23=RETR
```

Adjustments to be applied to PGE's financial results for the Earnings Sharing Mechanism

Utility Accounting Adjustments: Type 1

Taxes on Carrying Charge Income

This adjustment removes tax effects that result from the interest of deferral amortization, and makes ROE neutral to such amortization. The interest income on regulatory assets is recorded below-the-line in accordance with FERC guidelines. However, PGE has elected to record the income taxes on this interest income above-the-line (since they relate to utility operations and are a "regulatory asset"). This adjustment reclassifies the income taxes to below the line to appropriately match taxes and the income source of the taxes for this regulatory analysis.

Regional Power Act (RPA) Reversal

The effects of the RPA settlement are reversed for regulatory analysis. Since these benefits are a "flow-through" item to customers, their effects on tariffs and other revenues are removed.

Steam Sales and Sales for Resale

Sales for Resale and Steam Sales are reclassified from revenues to net variable power costs for this regulatory analysis.

Remove Wholesale Merchant Trading Margins per Order 97-196 and FAS 133 adjustments

We remove the gross wholesale merchant trading margin on term contracts by matching purchase and sale contracts considered speculative in nature. We remove the support costs for speculative trading so that the trading margin removed represents the margin on a fully allocated cost basis. We also removed FAS 133, FAS 71, and unrealized gains.

Out-of-period and Other Adjustments.

This adjustment eliminates out-of-period and extraordinary entries that would not be reflected in earnings test results.

Utility Tax Adjustment (Interest Adjustment)

This adjustment accounts for the differences between PGE Consolidated interest expense and PGE (utility only) interest expense. To accomplish this, we reduce interest expense, and the associated interest deduction for tax purposes. This reduction is made by the proportion of the interest costs allocated to non-rate supported activities. The effect of this adjustment is to increase income tax expense. The adjustment is calculated based on the methodology established in UE-79, and continued in UE-88 and UE-115.

Pension Credit

Pension fund "income" may be legally used, under ERISA, only for specific pension purposes. This adjustment reverses the pre-tax pension income, because it is not available for use against costs of general operation.

Regulatory Adjustments:

Two-Cities Sales Revenue
Both the 1991 and prior deferral of "excess power costs" related to the power purchased from BPA have been adjusted to comply with OPUC Order No. 91-186. We make this adjustment per a schedule (of amount and timing) through 2112, in accordance with Appendix C of the Order.

Wage and Salary Adjustment
Order 01-777 adjusted A&G costs based on the three-year wage and salary model. The adjustment provides equal sharing of pay increases higher than the change in the CPI between customers and the stockholders. This sharing recognizes wage and salary progressions in the work force.

Incentive Pay
This adjustment removes 15% of Teamworks incentive pay, 15% of the non-officer ACI incentive pay, and 100% of the Officer ACI incentive pay from expense and rate base, in accordance with Order 01-777. Note: per Order 95-1216 there is no disallowance of incentive pay (ACI or Teamworks) for Coyote Springs personnel due to their unique incentive labor contract.

Marketing and Sales
This adjustment is the amount by which PGE's non-labor marketing and sales costs (as identified by PGE ledgers N42217, N42221, N42223, and N42238) diverge from the historical three-year average (adjusted for inflation – see Order 01-777, stipulated adjustment S-29).

Advertising Categories "A" and "C"
This adjustment removes the amount by which "Category A" advertising exceeds one-eighth of one percent of the test year revenues, net of any authorized deferrals.

Retail Unbundling
This column removes 40% of PGE ledger N44172 as directed by the Commission in Order 01-777. The 40% disallowance represents the amount of costs associated with retail activity in this ledger.

Customer Accounts
This adjustment is the amount by which PGE's non-labor customer accounting costs (excluding ledgers N41331, N41381, N41382, and N41501) exceed the historical three-year average (adjusted for inflation) as directed by the Commission in Order 01-777.

Prior Year Tax Adjustment
Per the March 25, 1992 OPUC guidelines, this adjustment trues-up tax entries booked in the current year for prior years.

Supplemental Executive Retirement Plan (SERP)
Commission Orders 95-322 and 01-777 excluded this cost from PGE's revenue requirement.

Management Deferred Compensation Plan (MDCP)
Commission Orders 95-322 and 01-777 excluded this cost from revenue requirement.

ORDER NO. 03-214

ENTERED APR 10 2003

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1074

In the Matter of	)	
	)	
UTILITY REFORM PROJECT	)	
	)	
Petition for an accounting of the Federal, State and Local Income Tax Payments of PORTLAND GENERAL ELECTRIC CO., since its acquisition by ENRON Corp., and Appropriate Rate Adjustments and Refunds.	)	ORDER

DISPOSITION: PETITION FOR INVESTIGATION DENIED

On March 7, 2003, the Utility Reform Project (URP) filed a petition to open an investigation along with a complaint.[1] The Public Utility Commission (PUC) assigned Docket No. UM 1074 to this filing. URP's petition asks the Commission to commence an investigation to determine the amount that Portland General Electric (PGE) has paid in income taxes since 1997, and order PGE to refund to ratepayers, with interest, funds collected for paying income taxes that were not used for that purpose.

URP's petition is styled as both a request for an investigation under ORS 756.515 and a complaint under ORS 756.500. Staff's recommendation in this matter addresses only the request for investigation under 756.515.

At its public meeting on March 31, 2003, the Commission adopted Staff's recommendation to deny URP's petition to open an investigation regarding PGE's income taxes. Staff's recommendation is attached as Appendix A and is incorporated by reference.

[1] URP's Complaint that accompanied this petition has been docketed as UCB 13, and will be processed by the Administrative Hearings Division.

ORDER NO. 03-214

ORDER

IT IS ORDERED THAT Utility Reform Project's request to open an investigation is denied.

Made, entered and effective ______________________________.

BY THE COMMISSION:

____

Becky Beier
Commission Secretary

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A party may appeal this order to a court pursuant to ORS 756.580.

ORDER NO. 03-214
ITEM NO. 3

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: March 31, 2003

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** __________NA__________

DATE: March 24, 2003

TO: John Savage through Lee Sparling

FROM: Ed Busch

SUBJECT: UTILITY REFORM PROJECT: (Docket No. UM 1074) Requests Commission to open an investigation and order Portland General Electric to refund funds collected to pay income tax.

STAFF RECOMMENDATION:

I recommend the Commission deny URP's request to open an investigation regarding PGE's income taxes.

DISCUSSION:

On March 7, 2003, the Utility Reform Project (URP) filed a petition to open an investigation along with a complaint. The filing was docketed as UM 1074. URP's petition asks the Commission to commence an investigation to determine the amount that Portland General Electric (PGE) has paid in income taxes since 1997 and order PGE to refund to ratepayers, with interest, funds collected for paying income taxes that were not used for that purpose.

URP's petition is styled as both a request for an investigation under ORS 756.515 and a complaint under ORS 756.500. Staff's recommendation in this matter addresses only the request for investigation under 756.515.

In its petition, URP states that Enron Corp. (Enron), the parent company of PGE, has paid little or no federal, state or local income taxes since 1997 despite collecting over $400 million from PGE for that purpose. URP also states that "Substantial evidence exists that Enron/PGE engaged in a pattern of fraud and deceit upon the agency when it provided "proof" in rate proceedings that it would incur such tax liabilities but in fact had put in place numerous schemes for the avoidance and evasion of income tax liabilities. . ." URP's petition includes several figures that it believes were amounts included in customer rates for payment of income taxes that were not used for that purpose. According to the petition, PGE's rates "are based on fraud and misrepresentation by PGE."

Background

By Order 97-196 (Docket UM 814), the Commission approved Enron's application to exercise influence over PGE. The Internal Revenue Code allows a parent corporation to elect to file a consolidated federal income tax return that reports the combined income and expense items of the consolidated group. From 1997 until May 2001, Enron filed consolidated tax returns that included PGE's income and expenses. During that period, PGE calculated its federal and state income tax liability on its results of operations and forwarded to Enron those amounts. From May 2001 through 2002, while Enron was unconsolidated, PGE made its income tax payments directly to the taxing authorities

For ratemaking purposes, the Commission sets PGE's rates to reflect the costs of the company's regulated operations. That is, in a rate proceeding, PGE's rates are set based on its own revenues, costs and rate base for a given test year. Income taxes are calculated using PGE's net operating income. The tax effects of Enron's other operations are ignored for purposes of setting rates. This is consistent with standard ratemaking principles.[2]

Calculating PGE's costs, including income taxes, for ratemaking on a stand-alone basis protects PGE's customers from the financial difficulties experienced by Enron's other subsidiaries. When the Commission approved Enron's acquisition of PGE, it had the option of incorporating the effects of Enron's non-utility operations in PGE rates or treating PGE as a stand-alone entity. Consistent with long-standing OPUC policy, the Commission chose the latter approach. In adopting the stipulation in Docket UM 814, the Commission created a wall between PGE's operations and Enron's other subsidiaries. As stated by Order No. 97-196: "These conditions and commitments provide important measures and requirements, beyond those provided by the Commission's statutory authority and existing rules, to protect PGE's customers, competitors, and the public generally."

If PGE's rates were set in a manner that captured some of Enron's tax losses, PGE's rates would also have needed to reflect the expenses that created those tax savings, and customers would be worse off. Staff's counsel advised that it would be difficult for

[2] See Attachment to this staff report containing excerpts from Accounting for Public Utilities.

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. Moreover, such an approach may lead to confiscatory rates.

Issues

URP's petition raises two main issues relating to whether ratepayers are entitled to a refund. First, did PGE make "false or misleading representations" regarding the amount of income taxes that should be included in its customers' rates? Second, did PGE collect funds from its customers to pay taxes that were not used for that purpose?

The answer to the first question is clear. URP's petition contains no evidence that PGE made false representations in calculating the amount of income taxes that should be included in customer rates. As described above, PGE's rates that were in effect in 1997 and subsequent years were set on a "stand alone" basis in Docket UE 100 (effective December 1, 1996). Staff believes that income taxes were accurately calculated in that rate case using PGE's test year revenues, expenses and rate base.

As to the second question, it also is clear that PGE made its federal and state income tax payments to Enron while on a consolidated basis, and directly to the proper taxing authorities while on an unconsolidated basis. As reported in the company's annual report, FERC Form 1, from 1997 through 2001, PGE paid a total of $463.4 million in federal and state income taxes, of which $445.1 million related to its electric operations. In fact, this is more than the amount of income taxes that customers' rates were set to collect over this period, a total of $430.5 million. Hence, there is no substance to the argument that PGE collected amounts for payment of income taxes that it did not use for that purpose.

Even if PGE had paid out less for income taxes than it collected from customers, there would be no issue for an investigation. Rates are set based upon a utility's revenues and expenses (including income taxes) for a particular test period; actual results in subsequent years are almost certain to be higher or lower than estimated for the test period. In this case, PGE paid out more in income taxes that the amount calculated in the most recent rate case.

Staff certainly does not condone tax evasion by Enron, if that were proved to be the case. However, the OPUC does not have jurisdiction over whether or not Enron as a corporation appropriately paid its income taxes during the period Enron elected to file its taxes on a consolidated basis. Federal and state taxing authorities are responsible for ensuring that Enron paid the income taxes it owed.[3]

In short, staff believes that income taxes were properly included in PGE's revenue requirement and customer rates, and that PGE properly paid its income tax liability to its parent or to the taxing authorities, as appropriate. Whether or not Enron properly paid its income taxes to the IRS and the State of Oregon is beyond the purview of the OPUC. Any underpayments by Enron would be owed to those taxing authorities and their constituents, not to ratepayers.

Alternatives

The Commission can approve URP's application to open an investigation or it can deny the application. PGE has indicated that prior to this public meeting it will provide records that will enable the Commission to verify that PGE did, in fact, make its income tax payments reported in the company's FERC Form 1 for 1997 through 2001 either to Enron or directly to the taxing authorities. Regardless, URP's petition asks the Commission to take action in an area (possible underpayment of income taxes) in which the OPUC does not have jurisdiction. What the OPUC does have jurisdiction over is whether PGE's rates were set properly to include the company's income tax liability on a stand-alone basis. Staff finds that to be the case. Therefore, staff believes there is no reason for the Commission to open an investigation.

As noted above, URP's filing is also a complaint by URP against PGE under ORS 756.500. Staff's counsel advises that URP is still free to pursue that complaint. It may serve the complaint on PGE, if it hasn't already done so, and it may, at a hearing, present whatever evidence it chooses to support its complaint and its request for refunds.

PROPOSED COMMISSION MOTION:

Utility Reform Project's request to open an investigation be denied.

UM 1074
Attachment

[3] As stated in Accounting for Public Utilities (section 17.04[1]): "The election to file a consolidated tax return makes the parent corporation the agent of all corporations included in the affiliated group. This agency relationship includes, but is not limited to, the duties to file proper and timely consolidated tax returns, to receive deficiency notices, to file refund claims, to execute waivers of the statute of limitations, to respond to Internal Revenue Service audits, and to conduct proceedings in the courts."

ORDER NO. 03-214

Attachment

Excerpts from Accounting for Public Utilities (Publication 016, Release 19, November 2002)

Section 7.08[3]:

"It is not uncommon for a regulated utility to have subsidiary operations that produce tax losses which, on a consolidated tax return, offset taxable income from utility operations. . .The only approach that is consistent with standard ratemaking principles that prohibit cross-subsidization between utility and non-utility activities is to put the regulation operations on a 'stand-alone' basis and to assign the full tax burden to the taxable gain source and a tax benefit to the tax loss source. The basic theory is that the regulated costs should not be affected by the results from nonregulated operations."

Section 17.04[3]:

"Income tax normalization is consistent with a fundamental principle of the cost of service approach to ratemaking; the principle that consumers should bear only costs for which they are responsible. Under this principle, there is a well-reasoned, and widely recognized, postulate that taxes follow the events they give rise to. Thus, if ratepayers are held responsible for costs, they are entitled to the tax benefits associated with the costs. If ratepayers do not bear the costs, they are not entitled to the tax benefits associated with the costs.

"Regulators have long used a ratemaking procedure that explicitly embraces this principle. The procedure is to identify utility activities (revenues and costs) and compute taxes directly related to the utility activities.

"Non-utility operations involve financial risks that are different from a utility's regulated operations. When these risks are not borne by the ratepayers, it is unfair to make use of the business losses generated in those nonregulated entities to reduced the utility's cost in determining the rates to be charged for utility services. By the same token, when a company's nonjurisdictional activities are profitable, the ratepayers have no right to share in those profits, but neither are they required to pay any of the income taxes that arise as a result of those profits. Thus, a "stand alone" method (as opposed to a consolidated effective tax rate method) for computing the income tax expense component of cost of service is the proper and equitable method to be followed for ratemaking purposes."

UM-1121 / PGE EXHIBIT / 300
HAWKE-ELLIOTT

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Service Quality Measures

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony of

Steve Hawke
Bill Elliott

August 16, 2004

I. INTRODUCTION

Q. Please state your name(s) and position(s) with Portland General Electric.

A. My name is Steve Hawke. I am PGE's Vice President of Customer Service and Delivery. My qualifications are provided in Section II of this testimony.

My name is Bill Elliott. I am PGE's General Manager of Billing and Collections Operations. My qualifications are provided in Section II of this testimony.

Q. Please summarize your testimony.

A. We generally discuss parties' concerns that the proposed transaction will result in reduced service quality. We respond to ICNU's testimony (ICNU/200, Antonuk-Viceroy/5-8) stating that PGE's current service quality measures are only lagging measures that will not protect service quality. We also comment on the potential unintended consequences of Staff's proposed service quality measure for billing accuracy (Staff/700) and we outline our current processes that work to prevent billing inaccuracies.

Q. Do you support good service quality?

A. Yes. Good service quality is a hallmark of who we are as a company. The 2004 J. D. Powers Utility Customer Satisfaction Study showed that out of 12 western utilities, PGE ranks fourth for nonresidential customer service and is fourth on the residential cumulative customer service index. However, good service quality is not just part of PGE's corporate culture, it also makes business sense. We, as a company and individual employees, are tied to the communities we serve. It would simply be fiscally unwise to provide poor service.

Q. Please describe the X measures.

A. Unlike the other service quality measures in this program, X measures are forward-looking. They are not "lagging" measures. Rather, they assure that activities beneficial to customers are currently occurring. Our current X measures include vegetation management, service personnel count and basic inspection and maintenance programs. These service quality measures allow the Commission Staff regularly to check our progress on ongoing activities. The addition of X measures is a reasonable and cost effective means to enable Commission Staff's scrutiny of various service levels.

Q. Why do you include X measures in your service quality measures?

A. The X Measures ensure that PGE places continued emphasis on programs critical to service quality. Also, X Measures tend to more clearly measure progress because results do not have to conform to a formula.

Q. Is there anything else PGE does to ensure that service quality measurement is current?

A. Yes. We meet quarterly with the Oregon Public Utility Commission's (OPUC) Consumer Services Division to discuss current service quality. We discuss and appeal any "At-Fault" complaints we have received. We also try to identify any trends. With the OPUC's Safety and Reliability Division, we discuss safety, reliability and the X-measures as needed. Through these frequent meetings, we keep Staff up to date on our service quality measures status so that the year-end results are not a surprise. This is certainly not just a "lagging" process.

Q. Do you concur with Staff's recommendation that a billing accuracy service quality measure be added to the program(Staff/700)?

A. No. This service quality measure is problematic because it would require costly tracking, and would stifle innovation, while doing nothing to mitigate or remove the events that can result in errors.

Q. Do you support the concept of providing accurate bills to customers?

A. Absolutely. Providing timely and accurate billings to our customers is very important to us. We have instituted a number of programs and procedures to ensure that our billings are as accurate as possible.

Q. How many bills do you issue to customers?

A. We produce approximately 36,000 electric bills per day, which annually totals approximately nine million bills. Beyond billing for electricity services, we also bill for a variety of other services including claims, and distribution services such as line extensions, specialized metering and transformer rentals.

Q. Please describe the procedures you have in place to ensure your billings are accurate.

A. An accurate electric bill starts with an accurate electric meter. We test the accuracy of our meters on a regular basis. From the vast majority of our meters (standard watt-hour meters used for residential and small commercial customers), we test a sample of approximately 3,400 meters each year. We then seek to identify trends in accuracy such as particular models or "batches" that are beginning to fail. When we find a group that is failing prematurely, we institute a replacement program to remove them from service. We annually test meters where customers are receiving substation service. Our primary voltage service customers receive meter tests every five years. We are currently implementing an interface from the new meter management system to the customer information system (Banner) billing system, which will allow us to segment meters by load, and then biannually test the meters of customers receiving one aMW. The results of our testing programs are reported to the OPUC annually.

The next step in achieving accurate bills is an accurate meter reading. We strive to do so through several means including specific training of our meter readers, "bounds" checks within the meter reader's hand-held unit that prompts for a second reading when the initial reading appears to be "out-of-bounds." We are very proud of the accuracy of our meter readers. In fact, in the last two years (2002 and 2003), two of PGE's meter readers have been declared "Meter Reader of the Year" by Itron. One of the important criteria for this award is reading accuracy.

We read about 8.7 million meters per year. In 2003, we achieved a meter reading accuracy rate of 99.98%. Even with this high level of accuracy, the 0.02% error rate represents approximately 1800 meters per year.

Q. Will the installation of an automatic meter reading system eliminate meter-reading errors?

A. While we believe that an automated system may reduce the frequency of reading errors even further, it will not eliminate them. Equipment and systems always have the potential to fail or to suffer glitches. Also, it is reasonable to expect that the benefits or efficiencies of an automated meter reading system may not be realized for a few years because the performance reliability and maintenance needs of the equipment are currently unknown.

Q. Please continue with your description of the steps you take to ensure accurate billings.

A. The computer system that actually calculates the bill plays a critical role in billing accuracy. With any computerized system, there are at least two potential sources of errors: data input errors and coding errors.

We check for data input errors before mailing monthly bills to customers. The Company's billing system generates various reports detailing specified abnormalities, such as highs or lows. Approximately ten full-time employees manually review these reports to verify or correct the accuracy of the billing information prior to the printing of the bill. This is just a part of our monthly billing process.

We test the billing system for coding errors before putting any change into production. Before we put our current customer information and billing system (Banner) into production in August of 2002, it underwent an extensive testing phase. In fact, we delayed the planned "go-live" date to allow for additional testing. In total, the testing phase took about 24 months to complete and consumed about 51,200 labor hours of effort. Recently, PGE was given the "Best CIS Initiative" award of excellence for a North American investor-owned utility at the International CIS Conference for our implementation of Banner.

Whenever changes are made to Banner, we perform additional testing, albeit not to the degree of our initial implementation. Unfortunately, it is not feasible to test every billing combination and permutation possible. This is exemplified when we instituted the Williams Settlement Refund in June. This refund was given on a "billings on and after" basis rather than a "service on and after," which is our standard method of instituting price changes. Because of an undetected error in the Banner system, the adjustment began a day early. We discovered the error and adjusted bills the next month, but about

35,000 bills were sent with the incorrect credit amount. Again, no amount of testing will ensure 100% accuracy of a billing system, and even a minor error can affect a large number of bills.

Q. How are data input issues addressed?

A. Pricing changes vary from relatively simple to complex. A simple change is adjusting a single rate schedule. An example would be an adjustment to Schedule 101, the Energy Efficiency Adjustment, which requires inputting about 31 price changes. A general rate case is complex. Assuming only changes to energy prices and not to rate structures, a rate case would require about 1000 price changes. The addition of one new rate schedule can be complex because of the numerous potential variations. For instance, a single rate may have various billing components (ie. kWh, kW, kVAR, Unscheduled Energy, Maintenance Energy, Baseline Energy, etceteras).

Beyond whether building a rate for billing is simple or complex, we must build most rates twice. This is because the State of Oregon has a statute that prevents it from receiving a late payment charge greater than 0.667%, while the Commission-established rate for all other customers is 1.5%.

We have various controls in place to ensure that changes to the billing system are performed accurately. Our process includes an initial analysis of the rate change followed by a draft of the programming changes that need to be made. Programming requirements are then made in a test environment. Each step in our process has a test, review and approval process that must occur before a change is put into production. Historically, this process has required between 28 to 731 hours.

Q. Your comments have focused on the Banner system. Does PGE use other systems for billing?

A. Yes, for our largest customers with complex billings, we use our Power Billing System. Billings to Electricity Service Suppliers (ESSs) are performed by Excelergy. In fact, if one expands the discussion to all of the systems necessary to manage data and perform billings under our direct access environment, we have 19 systems and numerous data interfaces between systems. We have included as Exhibit 301, two diagrams that display how these systems interact. Obviously, this is a very complex set of systems, each of which have the same types of issues discussed above.

Q. Are any other checks made before bills are sent out?

A. Yes. PGE uses advanced technology to ensure that bills are printed and mailed correctly. A system that reads bar codes, coupled with manual controls, ensures that the bill printing and envelope insertion process is accurate. PGE's Printing and Mailing Services has received a number of local and national awards including, Mail System Management Association's and MAILCOM's 2001 Technical Excellence Award, International Publishing Management Association's 2002 Management Award, and the Greater Portland Postal Customer Council's 2001 Mailer of the Year Award.

Q. Have you reviewed the billing accuracy service quality measure as proposed in OPUC Testimony (Staff 702)?

A. Yes, we have.

Q. What is your reaction to the proposal?

A. As we have explained, we consider accurate billing to be very important. We believe, however, that the proposed service quality measure is premature. Staff states that it is presenting this service quality measure in this docket because of a "concern" that "OEUC will, in an attempt to cut costs, either neglect or attempt to change the PGE billing system" (Staff 700, Jackson/3, lines 8-9). However, it appears that PGE's system is performing better than other utilities according to the Billing Error Ratio Analysis presented in Staff's testimony (Staff 702, Jackson/5). Moreover, the service quality measure as presented requires further refinement to be consistent with Staff's stated goal. It is clear to us that the proposed service quality measure would benefit from a comprehensive review of the sort available in the context of a rulemaking proceeding. A forum for all parties, such as a rulemaking provides, would help us all ensure the right measurement and avoid unintended consequences.

Q. Please explain.

A. Many questions remain unanswered regarding the proposal's implementation and measurement. In the past, utilities and the Commission have implemented service quality measures after a period of testing and calibration to ensure that all parties are comfortable with what is being measured and what are the likely outcomes. This is not the case with the proposed billing accuracy service quality measure.

For example, Staff has indicated that PGE's customer information system (CIS) "may need to be revised to allow for more specific data collection related to billing problems" (Staff/702, Jackson/2). The costs to implement the measurement capability are unknown. Until such time as these unspecified revisions are identified and implemented, we cannot know if they are cost-effective or how they might affect the baseline level. Staff also indicates that exclusions and inclusions will be subject to negotiations between the parties (Staff/702, Jackson/2). Again, how can a baseline for measuring a service quality measure be set without such details? As a final example, Staff provides a list of possible "mitigating circumstances" that the Commission "may consider" (Staff/702, Jackson/2-3).

We need additional specificity on how the Commission would consider these. As herein noted, PGE goes to great effort to assure that billing system components are working effectively. It is unclear how Staff's proposed "remedies" are aligned with the purported benefits to customers.

Q. You have discussed a number of unanswered questions regarding the proposal. Do you have any other reasons to believe the proposal is premature?

A. Yes. We are unaware of any rationale for the particular performance level proposed: 0.6% the first year, 0.5% the second and 0.4% thereafter. All we are told is that performance levels have been negotiated in other jurisdictions, with some being as low as 0.1% (Staff/700, Jackson/4, lines 8-9). However, we have no information on the measurement used for these programs, including the particular inclusions and exclusions.

Staff implies that customers may not be getting "the accurate bills that they are paying for in their rates" (Staff/700, Jackson/2, lines 17-18) without indicating what level that is. Certainly, it is not 100% accuracy. As we discussed above, inaccuracies can occur in many ways. Ensuring perfection would require redundancies that would be extremely expensive. Customers are not paying for this level of service, and we do not believe that they should. There is always a tradeoff between accuracy and cost. We believe that we are at a reasonable place in that tradeoff.

In addition, special circumstances may affect billing accuracy. These might include the implementation of a new system(s) or other new initiatives designed to provide additional customer benefits and/or options. We believe that any proposal for serious consideration should address such issues.

Q. Please discuss any other issues you have with the proposal.

A. We have several other concerns. One thing that we have learned through our corporate and departmental goal setting processes is the importance of setting the right goals. Often, unintended consequences result from goals that are not set correctly. In other words, you tend to get what you measure even if it is not exactly what you want. For example, we believe that the proposed service quality measure could have the effect of stifling innovation and new offers to customers. Certainly there would be a reluctance to change what is working and producing accurate bills, when the possible outcome of the change could be a "revenue requirement reduction" (Staff/700, Jackson/6, lines 4-5). If the innovation or new offer would increase customer satisfaction, which we believe is the more over-arching goal, it is appropriate to risk some billing errors at the onset.

For instance, PGE recently introduced Schedules for Real Time Pricing (Schedule 87) and Partial Requirements Service (Schedule 75). These schedules present significant billing challenges. If a billing accuracy service quality measure were in place, it may have affected our decision whether or not to offer these new schedules.

Our second concern is related. If we assume that the over-arching goal indeed is customer satisfaction, we do not know how billing accuracy affects it. There obviously is some tie, but we have no information, nor does Staff present any, that suggests spending significant attention on this issue will increase customer satisfaction versus focusing on some other aspect of customer service.

Third, the Staff proposal appears to provide for penalties (revenue requirement reductions) on a monthly basis (Staff/702, Jackson/2) even if, on an annual basis, the service quality measure is met. This is not the underlying premise for the formulation and calculation of our existing service quality measures. For example, the At-Fault complaint (C1) standard is determined on an annual basis. Others, such as SAIDI (R1) and SAIFI (R2), are calculated on a weighted three-year average. We see no reason for this measure to trigger on a one-month blip.

Finally, we question whether this docket is the best venue for this discussion. Staff has indicated that this is a generic issue and that they are working with Northwest Natural on a similar measure (Staff/700, Jackson/7, lines 5-12). The service quality measure as presented also contains some apparent inconsistencies that need to be resolved. For example, the Billing errors section of Staff's testimony states that PGE would be required "to complete an investigation of any errors within 45 days of discovery to discern whether such an error could appear on other customers' bills" (Staff/702, Jackson/1), but the Records and Reports section of this same exhibit requires a written report for a billing error within 20 days (Staff/702, Jackson/3). A rulemaking docket is the appropriate forum for resolving apparent inconsistencies.

We address the issue of incentives in our closing remarks, but let us just say here that to neglect the billing system and allow inaccuracies to develop would be imprudent for any owner.

Q **Do you have other examples of potential unintended consequences?**

A. Yes. We mentioned the Williams Settlement Refund earlier. This was a refund of monies that the Attorney General received from the Williams Companies. It had nothing to do with PGE. We agreed to be the mechanism to distribute the benefit to our customers. We received no compensation for doing so. Would we have been willing to do this if the proposed service quality measure was in place? We do not know, but we do know that it would give us pause, and Williams Settlement Refund is not an isolated event. We are the billing administrator for Public Purpose Charges, and the current rulemaking, AR-481, is proposing we manually bill customers who self direct their Public Purpose Charge, which presents the Company with billing challenges unrelated to collection for its own services. The proposed service quality measure provides PGE with no flexibility for engaging in such efforts.

Q. How would you recommend that the Commission proceed on the issue of billing accuracy?

A. We believe the Commission needs to consider if customers will truly benefit from such a measure or if the measure will merely impose added costs for tracking and reporting while stifling innovation. If the Commission determines a billing accuracy service quality measure is appropriate, it should do so in a generic rulemaking proceeding that would adopt a standard that is relevant to all. This would bring many perspectives to bear on the subject and would allow a thorough vetting of issues and tradeoffs. PGE is willing to support this type of docket and would fully participate.

Q. Do you have any final remarks?

A. Yes. We would like to address the underlying issue of our current incentives regarding accurate billings. In our opinion, the interests of PGE, our customers, Oregon Electric and the OPUC are aligned on this subject. We all want billings to be accurate. We currently spend significant sums towards this goal. Putting aside for the moment the issue of customer satisfaction, we do not want inaccurate bills because they cost us money. They increase customer calls and complaints, and they are expensive to fix. It is in our own best interest to minimize the number of inaccurate bills. We know, however, that technology can fail and humans make mistakes. Thus, we will never reach 100% accuracy or, if we could, it would be prohibitively expensive. We are more than willing to work on this issue, but we believe that the proposed service quality measure is not the appropriate vehicle and that this docket is not the appropriate venue.

II. QUALIFICATIONS

Q. Mr. Hawke, What is your education background and experience?

A. My education includes two Bachelor of Science degrees from Oregon State University, one in electrical engineering and the other in mathematics. I then received a Masters degree in Business Administration from Portland State University, and I have completed the Public Utility Executive Program at the University of Idaho. I have worked at PGE for 31 years in various transmission, distribution, customer service and sales positions. My current position is that of Vice President of Customer Service and Delivery which I have held since 1997.

Q. Mr. Hawke, What are your responsibilities at PGE?

A. My responsibilities include oversight of Distribution, System Planning and Engineering, Transmission Services, Customer Accounts and Service, and energy efficiency and sustainability groups.

Q. Mr. Elliott, What is your education background and experience?

A. I have a Bachelor of Science in Education with Minors in History and Political Science from Western Oregon University, and I have completed the Management Training Program at the University of Chicago. My current position is that of General Manager of Billing and Collections Operations, which I have held for two years. I have worked for PGE for 33 years during which time I have worked in Meter Reading, Customer Service and Distribution. I have held management positions at PGE for 24 years. Prior to my current position, I have managed Energy Efficiency, Marketing and Operations, Customer Service, Customer Relations, Billing and Collections and the Call Center.

Q. Mr. Elliott, What are your responsibilities at PGE?

A. My responsibilities include oversight of Meter Services, Credit and Collections, Billing, Printing and Mailing Services, Billing Operations, Cash Remittance, Energy Service Supplier (ESS) Business Office and ESS Billing.

Q. Does this include your testimony?

A. Yes.

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List of Exhibits

PGE Exhibit	**Description**
301	Billing Systems Diagrams