BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

WUTC V. PSE

DOCKET NOS. UE-060266 AND UG-060267

DIRECT TESTIMONY OF MICHAEL L. BROSCH (MLB-1T)

ON BEHALF OF

PUBLIC COUNSEL

DATED JULY 19, 2006

NON-CONFIDENTIAL

DIRECT TESTIMONY OF MICHALEL L. BROSCH (MLB-1T)
Docket Nos. UE-060266 and UG-060267

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Michael L. Brosch. My business address is 740 North Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. By whom are you employed?

A. I am a principal in the firm Utilitech, Inc., a consulting firm engaged primarily in utility rate and regulation work. The firm's business and my responsibilities are related to special services work for utility regulatory clients. These services include rate case reviews, cost of service analyses, jurisdictional and class cost allocations, financial studies, rate design analyses and focused investigations related to utility operations and ratemaking issues.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the Washington Attorney General – Public Counsel Section ("Public Counsel"). Utilitech entered into a contract with Public Counsel to review and respond to certain non-traditional rate tracking proposals raised by Puget Sound Energy, Inc. ("Puget" or "Company") as part of its recommendations within its filing for an increase in its electric and gas rates and revenues.

Q. Will you summarize your educational background and professional experience in the field of utility regulation?

A. Exhibit No. ___ (MLB-2) is a summary of my education and professional qualifications. I have testified before utility regulatory agencies in Arizona, Arkansas, California, Florida, Hawaii, Illinois, Indiana, Iowa, Kansas, Michigan, Missouri, New Mexico, Ohio, Oklahoma, Utah, Washington and Wisconsin in regulatory proceedings involving electric, gas, telephone, water, sewer, transit, and steam utilities. In Washington I have testified in several major proceedings before the Commission, including Sprint's spinoff of its local telecommunications division (UT-051291), U S West rate cases (UT-950200, UT-970766), the U S West/Qwest merger (UT-991358), the most recent Verizon rate case (UT-040788) and the regulatory accounting for, and later sale of Qwest's directory publishing business (UT-980948 and UT-021120).

Q. Have you previously participated in energy utility regulatory proceedings?

A. Yes. I have participated in many electric and gas regulatory proceedings, as listed and described in Exhibit No. ___ (MLB-3). While much of my experience involves traditional rate increase or rate reduction cases, I have also addressed rate adjustment tracking tariffs as well as deferral accounting proposals on many prior occasions.

Q. What is the purpose of your testimony in this docket?

A. My testimony is intended to respond, on behalf of Public Counsel, to certain regulatory policy concerns raised by two proposed rate adjustment tracking mechanisms being advocated by Puget Sound Energy. The first proposed new tracking mechanism would increase electric and gas utility service rates between future PSE rate cases on a single-issue basis using a "Depreciation Tracker" to account for increases in depreciation expense that are anticipated by the Company.[1]

[1] John H. Story Direct Testimony, Exhibit No. ___(JHS-1T), pp. 73-78.

The second new rate tracking mechanism would partially "decouple" gas margin recovery to account for variations in usage per customer between rate cases through a proposed Gas Revenue Normalization Adjustment ("GRNA") tariff.[2] My testimony explains several problems arising from PSE's proposed new Depreciation Tracker and GRNA decoupling rate adjustment proposals and recommends that these mechanisms not be approved by the Commission.

Q. Please summarize the recommendations that are set forth in your testimony.

A. In general, I recommend that the Commission not approve piecemeal rate adjustment tracking tariffs for isolated elements of utility revenue requirements in the absence of compelling evidence that such piecemeal rate adjustments are warranted. My testimony explains how traditional test-year regulation achieves a balanced measurement of revenue requirements. I then describe how tracking tariffs and deferral accounting methods can be used as exceptions to the normal test-year approach, when warranted by extraordinary circumstances. I explain several general criteria that should be satisfied before piecemeal cost tracking tariffs should be accepted by regulators. When these criteria are applied to the specific depreciation tracking and gas revenue GRNA decoupling mechanisms Puget has proposed, I demonstrate why the Company's proposals should be rejected by the Commission.

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[2] Ronald J. Amen Direct Testimony, Exhibit No. ___(RJA-1T), pp. 27-57.

Q. How is the balance of your testimony organized?

A. My testimony is arranged by major topical area. A Table of Contents appearing at the beginning of the testimony sets forth this organization.

II. TEST PERIOD RATEMAKING CONCEPTS

Q. What is a test period and how is it used in utility regulation?

A. Energy utilities have traditionally been regulated based upon their cost to provide service, including an opportunity to earn a reasonable return on invested capital. The process used to evaluate and measure the cost of service and resulting revenue requirement is the rate case, in which a balanced review of jurisdictional expenses, rate base investment, the cost of capital and revenues at present rates can be undertaken at a common point in time, referred to as a "test period." *See, e.g., WUTC v. Avista Corporation*, Docket Nos. UE-991606, UG-991607, Third Supplemental Order, ¶¶ 14-16; *WUTC v. Washington Water Power*, Cause Nos. U-81-15, U-81-16, Second Supplemental Order, pp. 6-7 (rejecting company request for projected future test year, stating "[t]raditionally, this Commission has adopted the historical test year [.]"). In Washington, the test period is usually a recent actual 12-month period of time within which revenues at present rate levels are compared to operating expenses and the required return on average rate base, to determine whether an overall increase or reduction in revenue levels is needed. *Id.; WUTC v. Puget Sound Power & Light Co.*, UE-920433, 920499, 921262, Eleventh Supplemental Order, pp. 4-5.

It is essential for this synchronized review of both revenue levels and cost levels to occur within a carefully structured test period, because both revenues and costs tend to change with the passage of time as customers are added, inflation and productivity changes impact costs, capital market conditions change and sales volumes fluctuate. The dynamic nature of utility costs and revenues does not necessarily imply frequent rate cases. As long as revenues and costs remain in approximate balance, causing the utility's earnings to stay within acceptable proximity to authorized return levels, an electric or gas utility may be able go many years between rate cases.

An important element of traditional test period regulation is the incentive created for management to control and reduce costs, so as to maximize the opportunity to actually earn at or above the authorized return level between rate case test periods.

Another beneficial characteristic of traditional test year regulation is the intensive focus upon utility operations and costs within a formal proceeding in which Commission Staff and other interested parties can carefully examine or audit the components making up the revenue requirement. In contrast, piecemeal rate tracking tariff adjustments often receive little scrutiny or input from consumer representatives, even though significant customer impacts can result from such tariffs. These mechanisms place an added burden on Commission Staff and intervenors, and ultimately, regulatory bodies are likely to give less scrutiny to these costs.

Q. Under traditional test-period rate case regulation, what normally happens when a specific utility expense increases between test periods?

A. Increases in specific individual expenses between test periods, if nothing else changes, would directly impact the utility's pre-tax earnings and the achieved rate of return. However, all of the utility's costs and revenues tend to change over time. Customer and revenue growth or reductions in other costs often serve to offset or mitigate isolated cost changes, such that a utility company may be able to avoid rate increases for extended periods of time.

Sustained cost increases that were not offset by reductions in other costs or by increases in customer and sales levels may contribute to declines in achieved returns sufficient to justify the filing of a petition to increase rates. However, whenever a rate case occurs, all of the elements of revenue requirement are again measured and adjusted, in a balanced overall review that should account for cost increases in some areas being offset by cost savings in other areas. For example, Puget is forced to account for its higher customer count and sales volumes and its current capital market conditions and cost of capital in this docket, at the same time it has proposed to recognize a larger rate base and increased depreciation expenses. This balanced review of all elements of revenue requirement is a key characteristic of traditional regulation.

Q. You mentioned an "incentive" effect that results from traditional test period regulation. What is the incentive that is created?

A. Once revenues and costs are measured within the rate case test period, all changes such as cost reductions or sales margin growth cause improvements in the achieved actual return level, relative to Commission-authorized returns and are "favorable" from the shareholder perspective. Shareholders are rewarded with higher earnings between test years when management is able to successfully minimize cost increases, maximize productivity gains, or add profitable new customers to the system. Conversely, unfavorable changes between test years, such as cost increases or sales revenue declines can contribute to earnings below authorized levels. Punishment in the form of reduced earnings occurs when expense increases or sales and margin losses between rate case test periods are not fully offset by revenue gains. In this way, regulatory lag provides a symmetrical incentive for management that can either reward cost containment and the profitable growth in sales or temporarily punish excessive cost increases until the time when a new rate case can be litigated.

Q. Does the use of projected or "future" test period approach, as compared to the actual or "historical" test period approach that is used in Washington, change the balance that is achieved among test period ratemaking elements?

A. No. A balanced and matched measurement of the revenue requirement elements is still pursued. Several state regulatory commissions employ projected (aka "future") test period ratemaking using budgeted information, rather than actual recorded accounting data from a historical year. Use of such projected test period financial data introduces management, staff and intervenor judgment and debate regarding how sales volumes, employment levels, non-labor expenses and rate base investments may change in the future rate-setting period. However, the desired end-result is still a matched comparison of revenues to costs within an internally consistent test period. The test year approach used, projected versus historical, does not change the need for a balanced comparison of revenues at present rates to the overall cost of service in order to determine rate changes that are needed. Unfortunately, while presumed to be desirable at reducing regulatory lag, projected test year analyses are inherently more complex in practice because of difficulties associated with accurately predicting future events, documenting assumed future events in the absence of factual data and the challenges involved in defending such predictions upon critical review in a litigation setting.

Q. What are the most common types of exceptions to the standard approaches to test period rate case regulation of energy utilities that you have described?

A. Exceptions to the synchronized test period review of revenues and costs have been allowed in limited instances by regulators for certain large and volatile cost elements that are beyond the control of utility management and that might produce unacceptable financial outcomes if not allowed special treatment. The most common exception to traditional test period regulation is the widespread utilization of purchased energy adjustment clauses to periodically adjust rates, so as to track changes in the costs of purchased gas for local gas distribution utilities or to track changes in the costs of generation fuel and/or purchased power incurred by electric utilities. Power Cost Adjustment ("PCA") and Purchased Gas Adjustment ("PGA") mechanisms are employed by many state regulators because fuel and purchased energy commodity costs are recognized to be:

- Large in relation to the total cost to provide electric service, and
- Subject to market forces (rather than management control), and
- Volatile and difficult to reasonably quantify in rate cases, and
- Substantial enough to cause potential earnings volatility if not tracked.

Another exception to traditional test period regulation that occurs with some regularity is the concept of deferral accounting, which is sometimes referred to as an accounting authority order. For designated transactions or types of costs, the utility may be allowed to deviate from the accounting otherwise required under Generally Accepted Accounting Principles ("GAAP") or the Federal Energy Regulatory Commission ("FERC") accounting principles set forth in the Uniform System of Accounts ("USOA"). Examples of accounting deferral orders might include extraordinary storm recovery costs or deferral of costs associated with merger transaction and transition costs, in an effort to mitigate the financial impact of extraordinary events or to better match cost recognition to the periods thought to benefit from a merger of utility entities.

Q. Has the Commission noted any of these considerations in allowing Power Cost Adjustment mechanisms in Washington?

A. Yes. In its recent decision in the PacifiCorp rate case, the Commission reaffirmed certain principles that should be incorporated in a properly designed PCA, stating the following:

- "The purpose is to recognize variability in the cost of operating *existing* power supply resources as a result of abnormal weather conditions that are out of a utility's control. Ratepayers understand the connection between weather and rates;
- Power cost adjustment mechanisms are *short-run* accounting procedures to address *short-run* cost changes resulting from unusual weather;
- It is not appropriate to include new resources in a power cost adjustment mechanism. New resources must be considered in general rate cases or power cost only rate cases;
- Ratepayers should receive the benefit of a reduction in cost of capital, as a power cost adjustment introduces rate instability for ratepayers and earnings stability for stockholders, and;
- Power cost adjustment mechanisms should not interfere with least cost planning, conservation, or other regulatory goals.[3]

[3] *WUTC v. PacifiCorp*, Docket No. UE-050684, Order No. 4 at ¶ 91 (April 17, 2006). ("2006 PacifiCorp GRC Order"). Citations omitted, emphasis in original.

Q. Why is a discussion of traditional test period regulation, versus rate tracking and deferral accounting, relevant to this Puget rate case proceeding?

A. As noted above, Puget is requesting Commission approval of two new piecemeal rate tracking devices to change rate levels between rate cases for increased depreciation expenses and for post-test-year changes in gas usage per customer. Public Counsel, on the other hand, seeks to restrict the use of these exceptional regulatory treatment to only instances where there is compelling evidence that piecemeal ratemaking is in the public interest. It is my belief that parties to regulatory proceedings should not be allowed to tinker with the balance inherent in traditional test period ratemaking processes by isolating certain revenue or cost elements for rate tracking or deferral accounting treatment in the absence of compelling evidence that traditional regulation is not working effectively. The testimony that follows explains certain generalized criteria that the Commission should consider in evaluating requests by energy utilities to selectively depart from balanced test period regulation in changing rates and revenues and then applies such criteria to Puget's specific new rate tracking proposal in this Docket.

Q. What general problems are created by the use of Rate Trackers, Accounting Deferrals and Rate Case True-up devices?

A. The general problem associated with use of these regulatory tools is the potentially serious distortion of the "matching" that is desirable in a rate case test year. This is often referred to as the "matching" principle in ratemaking – which recognizes the importance of matching all revenues and costs (expenses, rate base, rate of return) at a consistent period of time to determine needed changes in utility pricing. I understand that the Commission has recognized this principle in a recent Avista case in its findings regarding an adjustment for the Coyote Springs II generating plant. The Commission's Order states in part: "The matching principle requires that all cost-of-service components – revenue, investment, expenses and cost of capital – must be considered and evaluated at a similar point in time." *WUTC v. Avista Corporation*, UE-050482, UT-050483, Order No. 5, ¶ 111.

As I mentioned in prior testimony, all elements of the revenue requirement calculation are dynamic through time and changes that are favorable tend to offset other changes that are unfavorable. For example, adding customers and the related revenue growth can help "pay for" increases in operating expenses, while growth in the depreciation reserve tends to offset to some degree the construction activity that adds new Plant in Service.[4] If a party is allowed to select certain items for special treatment with a rate tracker or through deferral accounting, one can reasonably expect that the selected items will be "cherry picked" by that advocate so as to influence the regulatory process to the sole advantage of that party. Other specific concerns with these regulatory exceptions to balanced test year analysis include:

- Reduction of management incentives (by eliminating regulatory lag),

[4] New customers increase utility sales volumes, yielding margin revenues (revenues less fuel costs) that contribute toward recovery of the fixed costs of the business. Some incremental non-fuel costs may also be caused by adding new customers, if facilities extensions are required that exceed advances or contributions pursuant to tariff or rule.

- Shifting of cost responsibility and risk to customers who are least able to influence cost levels or sales levels.
- Increases in tariff and bill complexity that may be difficult to explain to customers or that may complicate customers' ability to control their costs.
- Administrative complexity and costs associated with audit verification, administration of complex accounting entries, cost allocations and/or tariff calculations, often on an accelerated procedural schedule.
- Potential for inadequate regulatory oversight and auditing of tariff application.

With these concerns in mind, the exceptions to normal test year ratemaking using rate trackers and/or deferral accounting should only be allowed when extraordinary circumstances exist that preclude the setting of just and reasonable rates through traditional test year procedures.

Q. Under what circumstances should regulators consider adoption of tracking tariffs and/or regulatory deferral accounting for specific changes that occur between rate case test years?

A. Rate trackers and cost deferrals should be approved only in instances where compelling circumstances justify departure from traditional test period review of all costs and revenues within rate case proceedings in which the overall revenue requirement can be audited and considered in a balanced and synchronized manner. Costs or revenue changes to be deferred or rate tracked should generally have all of the following attributes to merit such exceptional and preferential rate recovery treatment:

1. Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases.
2. Beyond the control of management, where utility management has little influence over experienced revenue or cost levels.
3. Volatile in amount, causing significant swings in income and cash flows if not tracked.
4. Straightforward and simple to administer, readily audited and verified through expedited regulatory reviews.
5. Balanced and not distortive of test period relationships –reflective of factors that mitigate impacts in a manner that preserves test year matching principles.

In the testimony that follows, I will apply these general criteria to the two proposed rate trackers being advocated by PSE, so as to illustrate why these Company proposals should be rejected.

Q. Do regulated utilities in Washington, if they experience significant attrition that compromises their financial strength, have any options for regulatory relief other than piecemeal ratemaking trackers or deferrals?

A. Yes. In general, past Commission orders show that Washington utilities have been allowed interim or emergency rate relief when facing very serious financial circumstances, if required factors are present.[5] In the event PSE actually experiences serious attrition problems under traditional regulation in the future, the Company may be able to qualify for interim or emergency rate relief as a remedy for such problems.

III. REGULATORY LAG IS SYMMETRICAL AND PROMOTES EFFICIENCY

Q. In previous testimony, you described how the balanced measurement of all elements of the revenue requirement within a test period is important. What is "regulatory lag" and how does it impact utility regulation?

A. Regardless of whether we use actual historical test period data or projected future test period financial estimates to determine public utility revenue requirements, there will always be a "lag" between the timing of available financial data that is incorporated into evidence relied upon by the regulator and the subsequent period of time during which new utility rates are effective. Historical test periods necessarily rely upon actual, recorded financial data that is at least several months old at the time of rate hearings and may include data at the beginning of the period that is up to two years old by the time a final order is issued. Advocates of the projected test period approach claim that a significant benefit associated with the use of budgeted future financial data is the ability to reduce regulatory lag by relying upon data that is more representative of the cost and revenue environment expected while the new rates would be effective. However, even the recent actual and estimated data used in

[5] The Commission has broad powers to award interim relief "when it deems it justified." *WUTC v. Verizon Northwest, Inc.*, UT-040788, Order No. 11, ¶21 (footnote omitted). The *Verizon* order lists the 20 orders over the last three-plus decades in which the Commission has responded to such requests. *Id.,* n. 10.

assembling projected test period revenue requirement calculations must be fixed at a point in time for presentation before the Commission and is therefore subject to regulatory lag and the financial circumstances faced by the utility continue to change.

Regulatory lag is therefore an unavoidable characteristic of test period regulation that can work to the advantage or disadvantage of the utility – depending upon how future actual revenue and cost trends compare to amounts used to determine the revenue requirement. Symmetrical risks and opportunities arise for utility ratepayers and shareholders as a result of regulatory lag because favorable and unfavorable changes in revenue requirement can produce over or under-earning outcomes until either the utility or some other party initiates a new rate case proceeding.

Q. Are any regulatory incentives created by the existence of regulatory lag?

A. Yes. As discussed above, one obvious and desirable incentive created by regulatory lag is that management is encouraged to control and minimize operating expenses and capital expenditures at economically efficient levels so as to optimize achieved earnings between rate cases. Additionally, management faces an incentive to attempt revisions to the traditional regulatory framework, either through legislative initiatives or regulatory proceedings, in an effort to change the methods and procedures through which cost of service changes can be translated into increased revenues. The new tracking tariffs for depreciation cost increases and for gas usage per customer that are proposed by Puget are examples of efforts to “sweeten” the regulatory framework with preferential ratemaking treatment for isolated elements of the overall revenue requirement calculation.

Q. How does the creation of rate tracking tariffs, such the proposed new depreciation expense tracking and GRNA customer usage tracking, impact regulatory lag and the incentive to utility management that is created by regulatory lag?

A. Tracking tariffs can virtually eliminate the regulatory lag incentive. PSE's depreciation tracker, if approved, would reduce the incentive faced by management to carefully manage capital expenditure levels between rate case test years, because any increases in depreciation expense caused by transmission and distribution (T&D) capital spending can be translated into rate increases outside of a formal rate case proceeding. On the other hand, with respect to the GRNA proposal, PSE has little influence over gas usage per customer volumes because most of such fluctuation between rate cases is caused by weather variation and by customer usage impacts caused by appliance efficiency improvements, price elasticity and other externalities. I discuss gas usage incentive concerns in a later section of my testimony.[6]

IV. EXPANDED RATE TRACKING SHIFTS RISKS AND COSTS TO RATEPAYERS

Q. How would Commission approval of Puget's proposed depreciation expense tracking tariff impact customers?

A. Puget's proposal represents higher prices for consumers with no corresponding

[6] See pp. 40-42.

demonstrated benefits. In its proposed form, PSE's proposed Depreciation Tracker would immediately increase rates by $7.9 million for electric customers and by $10.9 million for gas customers.[7] Then, in subsequent years, additional rate increases would occur for further increases in depreciation expense using the form of calculations presented in Mr. Story's testimony at pages 74 and 75. Notably, there is no guarantee that PSE will delay filings for traditional rate increases in the future, even if the proposed tracker is approved.

Q. How would Commission approval of Puget's proposed GRNA decoupling tracking tariff impact customers?

A. Again the Company's proposal promises higher prices paid by consumers, with no guarantee that PSE will not seek traditional rate increases in the future or accept a lower rate of return so as to recognize the shifting of sales volume risks to customers. I will discuss in greater detail how the proposed GRNA would impact customers in a later section of this testimony.

Q. What do these two alternative ratemaking proposals have in common?

A. Both of PSE's proposed new rate trackers represent management's selection of isolated elements of the revenue requirement calculation, where future changes are expected to have negative profit consequences, for piecemeal rate changes that would shift costs and risks to ratepayers. These regulatory "sweeteners" would distort the Washington regulatory framework and would systematically disadvantage ratepayers

[7] Direct Testimony of John H. Story, Exhibit No. ___(JHS-1T), p. 76.

who are entitled to a more balanced assessment of the overall cost of service when utility rates are changed.

Q. Has PSE made any showing that it will need the additional future revenues that would be created through GRNA and Depreciation Tracker piecemeal rate increases in order to have a reasonable opportunity to earn the allowed rate of return?

A. No showing has been made that any known and measurable changes in future PSE revenues or expenses would contribute to significant earnings deficiencies that could not be sufficiently addressed under traditional regulation. PSE does offer what it calls "attrition" calculations based upon trending of historical expense levels, but does not advocate direct utilization of the results.[8] Other than speculation regarding possible future PSE capital spending levels and internally developed financial forecasts, no evidence of known and measurable financial changes has been presented.

Q. If the Commission approves the GRNA and depreciation expense trackers, over the objections of Public Counsel, will operating risks normally borne by shareholders be shifted to ratepayers?

A. Yes. The two new trackers, if approved, would substantially sweeten the regulatory framework within which PSE conducts is business. Any future increases in depreciation expense that would normally be borne by shareholders between rate case

[8] Direct Testimony of John H. Story, Exhibit No. ___(JHS-1T), pp. 62-66 and Exhibit Nos. ___ (JHS-11 and JHS-8). See also Direct Testimony of Karl R. Karzmar, Exhibit No. ___(KRK-1T) at pp.36-41 and Exhibit Nos. ___ (KRK-6 and KRK-7).

test years, to be funded from reductions in other utility costs or from customer sales gains, would instead be tracked through rate changes to be funded on a piecemeal basis by ratepayers. Similarly, if normalized gas usage per customer declines between test years, PSE would increase rates to shift such risk to its customers on a piecemeal basis.

Q. Has the Commission previously authorized rate tracking mechanisms that benefit PSE shareholders, by shifting the risks arising from large and volatile cost changes to ratepayers?

A. Yes. PSE is already insulated from significant risks associated with changes in volatile purchased energy costs through its Commission-approved PCA and PGA mechanisms. Puget is over-reaching in this case, by seeking two new rate tracking mechanisms to further transfer its operational risks onto ratepayers.

Q. Would it be appropriate for the Commission to make a downward adjustment to the authorized return on equity if revenue decoupling or the proposed depreciation expense tracking tariff is approved in this Docket?

A. Yes. The return on common equity that is allowed by the Commission is intended to compensate for the financial and business risks that are borne by equity investors in Puget Energy, Inc. stock. Commission approval of the depreciation expense tracking and GRNA tariffs would directly and favorably impact PSE's future revenues and income levels while reducing existing levels of operating risk arising from regulatory lag. The allowed return on equity should therefore be commensurately lower with the depreciation tracking and GRNA tariffs in place than is required without such regulatory sweeteners.

V. COMPLEXITY AND ADMINISTRATIVE BURDENS ARE INCREASED BY TRACKING TARIFFS

Q. How do tracking tariffs impact regulatory complexity and administrative costs?

A. The addition of tracking tariffs adds complexity to regulatory processes in several ways. First, each new tracking tariff creates new regulatory reporting in support of periodic price changes that must be created by utility company staff and then reviewed by Commission personnel. Then, it may be necessary for Commission Staff to organize and conduct audits of the underlying financial data beneath the filings, since customer prices are directly impacted by such data. If any disputes arise from either informal review procedures or more comprehensive audits, it may be necessary to develop formal discovery and dispute resolution procedures. When applicable review procedures are completed, the utility must implement the rate change along with any customer disclosures that may be required and then be ready to respond to customer inquiries arising from rate changes. Unfortunately, because tracking tariffs are designed to facilitate expedited rate changes, the process just described must often occur within a compressed timeline that can frustrate efforts and thorough review and/or contribute to increased costs to the utility and the regulatory agency.

Q. Is it reasonable to expect that PSE employees and WUTC Staff personnel would be burdened with significant additional work if the GRNA were adopted?

A. Yes. Mr. Amen's testimony and his Exhibit Nos. ___(RJA-8) and (RJA-9) illustrate and describe the monthly deferral calculations for a single month and provide details of the proposed GRNA tariff, indicating considerable effort would be involved in collecting and assembling supporting information and performing calculations to derive and implement GRNA rate changes. Given the importance of the calculations to customers' rates, WUTC Staff personnel would need to be tasked to review and audit such calculations. In Public Counsel Data Request No. PC-047, the Company was asked for its "best estimate of annual administrative and regulatory costs to be incurred if the GRNA decoupling mechanism is approved by the Commission and implemented by Puget." Objecting that the question "is speculative," the Company then responded that the additional impact on PSE would be "minimal" and that while it was "not in a position to estimate the amount of WUTC Staff time" that would be involved, it did not anticipate it would be "unduly burdensome."

I do not agree with this assessment. Even if not readily determined at this time, any regulatory complexity and burden added by the GRNA would be additive to the regulatory administrative burden and costs already arising from the Company's PGA and PCA. It would certainly not be "minimal" if significant disputes arise over implementation details.

Q. Would PSE's proposed Depreciation Tracker, if approved, also add to the cumulative administrative burden upon the utility and the WUTC Staff?

A. Yes, for the same reasons discussed above with respect to the GRNA.

VI. REBUTTAL TO PUGET'S DEPRECIATION TRACKER WITNESS

Q. Beginning at page 57 of his testimony, Mr. Story describes regulatory lag and attrition, which he says, "…can occur if an historical test year is used for setting rates for a company that is experiencing considerable growth or replacement of infrastructure and its marginal cost of serving customers is greater than its embedded cost of serving customers." Do you agree with these general observations?

A. I agree that actual returns earned by a regulated utility will depart from authorized return levels, depending upon whether costs (expenses and depreciable net investment) grow more rapidly than revenues. However, utilities that are experiencing considerable growth do not necessarily face earnings attrition. If growth is causing attrition, there may be problems with main and/or service line extension policies or with rate design. Absent these problems, customer growth is normally accretive to earnings by adding margin contribution to help the utility recover its significant fixed costs, including the overheads of the business.

With respect to the Depreciation Tracker proposal, PSE argues that it may suffer future "attrition" because of the use of an historical test period while it is experiencing considerable growth or replacement of infrastructure.[9] Mr. Story's attrition concern arising from "replacement of infrastructure" is intuitively appealing, but is not supported by any empirical analysis in the Company's filing. Utility companies are continuously replacing portions of the embedded investment in utility plant in service, by retiring "old" plant and installing "new" plant at generally much higher current replacement prices. Some of this continuing investment is needed to extend facilities to new customers or to expand the capacity of gas and electric facilities, while other plant investment may be triggered by excessive gas leaks or outage response costs arising from substandard existing electric or gas facilities. Other categories of investment include replacement of facilities that are simply worn out and no longer fully functional, relocation of facilities for public improvements, replacement of assets that are more costly to maintain than replace, compliance with regulatory mandates or installation of new automation technologies that promise operational efficiencies. If "infrastructure replacement" were the systemic attrition problem that Mr. Story suggests, every energy utility in the country would need annual rate increases to contend with the generally higher replacements costs for retired plant assets. Obviously many other factors, including productivity effects (which can be difficult to isolate) also influence utility revenue requirements, in ways that serve to mitigate such inflationary pressures.

[9] Direct Testimony of John H. Story, Exhibit No. ___ (JHS-1T), pp. 57 and 63-66.

Q. At page of 64 of his direct testimony, Mr. Story references "an attrition adjustment in this case based on the trended methodology that the Commission has accepted in some historic rate cases." In your opinion, should the Commission rely upon the electric or gas "attrition analysis" that is sponsored by Mr. Story (electric operations) or Mr. Karzmar (gas operations) to quantify any additional regulatory relief for PSE?

A. No. Trending of historical accounting data does not produce reliable estimates of changes in future revenues or cost levels that would help to define future revenue requirements or needed attrition allowances. If ratemaking were this simple, regulators could have two rate case proceedings for each utility they regulate, compare how costs and revenues changed between the two test years, and then extrapolate the rates of change to prescribe utility rates for many future years (and then retire). Notably, PSE does not use this trending approach to develop its own internal management financial forecasts of future revenues, costs and operating income.[10] Most telling is the fact that PSE has not advocated use by the Commission of results from the trending calculations it has performed.

Q. At page 63 of his direct testimony, Mr. Story states, "The Company is proposing a new Depreciation Tracker that would true up revenues for changes in depreciation expense related to natural gas and electric transmission and distribution ("T&D") capital investment, which I describe in greater detail

[10] Direct Testimony of John H. Story, Exhibit No.___(JHS-1T), p. 65. Comparisons between a trending-based attrition allowance for gas operations and the quite different results from internal management forecasts for gas operations are discussed by Mr. Karzmar at Exhibit No. ___(KRK-1T), p. 39.

below." Should a Depreciation Tracker for changes in T&D depreciation expense be approved for PSE?

A. No. Such a rate tracker would be distortive of test period relationships. Some of the new electric and gas distribution plant investment that PSE would like to include in the proposed new depreciation tracker to increase customer rates on a volumetric basis would relate to new plant investment made to connect new customers. However, revenues and margins earned by PSE from serving new customers between rate case test years are retained for shareholders, because there is no existing or proposed tracking tariff that would reduce gas and electric prices to account for such margin growth. Raising the rates payable by all customers through a tracker for depreciation increases on plant investment made to serve new customers is blatantly unfair, because there is no proposed tracker accounting for the incremental profit margins earned from sales to the new customers. The mechanics of the tracker calculation would only indirectly account for load growth by dividing depreciation expense by total volumetric throughput that increases through time,[11] but this approach does not accurately account for additional margin income PSE will actually collect from new customers that will be available to help "pay for" increased depreciation and other cost changes.

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[11] *Id.* p. 74. In the example Depreciation Tracker calculation tables, "Delivered Load (MWH)" and "Delivered Load (thousand therm)" are allowed to increase from test year levels to estimated 2007 levels.

Q. Would Commission approval of Puget's proposed depreciation expense tracking tariff disturb the existing regulatory lag incentives associated with capital expenditures?

A. Yes. If changes in depreciation expense are tracked into piecemeal rate increases between rate cases, the incentive that would normally exist to carefully control incurred costs for capital expenditures would be blunted. With such a tariff in place, Puget management could, and probably should, focus more attention upon other business issues and care less about stringent cost controls over capital expenditures that can simply be tracked into higher depreciation tracker rate levels charged to customers. In fact, the preferential regulatory treatment that Puget now proposes for depreciation on certain capital additions may introduce a bias into otherwise balanced economic analyses of specific capital projects that promise operational savings. For example, if Puget could invest more capital in its gas distribution plant to reduce its leak response expenses below levels that are built into rate case revenue requirements, depreciation on the capital invested would translate into piecemeal rate increases, while the favorable change in operations and maintenance (O&M) would be retained solely for shareholder benefit until leak response expenses were reviewed and updated in the next rate case test period. This is an example of an input mix bias problem that can arise from inconsistent regulatory treatment of selective elements of the revenue requirement – where certain resource inputs to the business (in this example capital investment) are afforded preferential regulatory treatment in relation to alternative input costs (expenses associated with leak response service calls).

While gas leaks should be minimized for both economic and public safety reasons, the introduction of disparate regulatory treatments may lead to sub-optimal decisions by management in evaluating specific gas distribution plant replacement projects where the cost/benefit relationship is questionable.

Q. Is it possible for new future investment in T&D plant to create operational efficiencies that reduce expenses from the levels included in test year revenue requirement calculations?

A. Yes. Many types of O&M expenses are influenced by the age and condition of utility plant. As noted above, service calls for gas leaks and gas leak repair expenses are impacted by the condition of mains and service lines and the systematic replacement of problem areas in the gas distribution system can produce profound improvement (i.e., reductions) in these costs. In the electric business, the replacement, relocation or undergrounding of distribution facilities can save on outage restoration as well as tree/brush forestry management costs. Automation opportunities exist through modernization of T&D facilities, with examples such as automated meter reading and substation automation, where staffing and O&M expenses may be avoided through new capital investments.

The "infrastructure investments" that Mr. Story claims are contributing to "financial pressures" for the Company[12] actually represent capital expenditures that are aimed at efficiently serving new and existing customers, growing margin revenues and controlling expense levels. Therefore, depreciation expense on T&D investments

[12] *Id.* p. 78, l. 1.

should not be subject to single issue rate tracking unless all of the corresponding operational impacts of such tracking are also recognized within the tracker. However, as a practical matter, it would likely be impossible to design a comprehensive tracking mechanism to capture all financial impacts arising from new capital investment, because of the capital intensity of the utility business and the complex ways in which changes in utility plant assets impact business operations.

Q. Would the financial impact of tracking changes in electric and gas T&D depreciation expense be substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases?

A. No. In the back-casting analysis performed by PSE, the annual financial impacts of the proposed Depreciation Tracker, if it had been in effect in the years 2003 through 2005, would have ranged from $3.1 to $5.9 million per year. When these annual amounts are reduced for income taxes at the 35 percent statutory Federal rate, these amounts represent no more than 2.5 percent of Puget Energy's reported 2005 consolidated net income.[13]

Q. Should increases in T&D depreciation expense be viewed as entirely beyond the control of management?

A. No. While it is true that significant capital investment is continuously required by utilities to replace, extend and modernize electric and gas T&D facilities,

[13] Puget Energy, Inc. 2005 Annual Report, page 2 shows 2005 Consolidated Net Income of $155.7 million. $5.9 million times (1-35%) / 155.7 = 2.5%.

management has considerable discretion and control over capital expenditure timing and cost levels and should be actively involved in facilities planning and design, construction workforce management, materials procurement, contractor bidding and administration and other elements of capital expenditure optimization.

Q. Can the input values and computations involved in administering the Company's proposed Depreciation Tracker tariff be readily audited and verified through expedited regulatory reviews?

A. No. The primary input values are calculations of annual depreciation expense which result from application of approved depreciation accrual rates to all of the balances within PSE's gas and electric T&D utility plant accounts. While a cursory review of depreciation expense accruals and the resulting tariff rate calculations would not by itself be burdensome, ignoring the GRNA proposal of PSE and other utilities' potential future tracker proposals, any intensive review of changes in the underlying Plant in Service accounts that drive depreciation expense would not, in my opinion, be possible as part of an expedited review. Plant in Service balances represent the cumulative accounting for all of the construction work orders that support plant additions and retirements occurring throughout the year, representing a significant audit effort if such balances needed to be thoroughly analyzed before being allowed to impact utility rates. In a rate case, the Staff and intervenors have an opportunity to scrutinize new utility plant additions and retirements that have occurred since the prior case test year, and then more rigorously test and verify the depreciation accruals that result from changes in Plant in Service.

VII. REBUTTAL TO PUGET'S GAS REVENUE NORMALIZATION ADJUSTMENT (GRNA) WITNESS

Q. At pages 27 through 38 of his testimony, Mr. Amen describes several concerns he has with traditional ratemaking for gas utilities, including annual variations in actual sales volumes and margins due to weather fluctuations, declining gas consumption per customer due to conservation effects, and the corresponding financial impacts felt by PSE. In your opinion, are these new concerns that require dramatically changed regulatory approaches?

A. No, these are not new concerns. Gas distribution utilities have always been subject to the sales impact of weather variation around "normal" degree day levels, which in some years causes significant gas margin (revenues less purchased gas cost) variances above or below intended levels. However, over multiple years, the effects of actual heating season weather conditions will tend to average out near the normalized level used to set gas utility delivery rates. Mr. Amen has not demonstrated any changed circumstances in weather trends or impacts upon PSE that now justify modification of the Commission's long standing regulatory approach to balanced test year regulation based upon normalized weather conditions.

The more gradual conservation trend reducing PSE's gas usage per customer is also not a new phenomenon, because consumers have been replacing less efficient furnaces and other appliances and building tighter, more efficient houses for many years. Indeed, Mr. Amen states at page 33 of his direct testimony, "The yearly decline in residential use per customer has averaged approximately 1.2% since 1994 on a weather-adjusted basis and PSE expects this trend to continue into the future". No dramatically changed facts or circumstances now support elimination of normal test year ratemaking that sets gas delivery rates based upon then-current normal weather sales volumes, allowing productivity gains elsewhere in the business to offset the gradual effects of changing sales volumes.

Q. Should the Commission approve PSE's proposed GRNA tariff because of weather effects upon customer usage or because of conservation effects?

A. No. Gas utility delivery revenues (revenues less gas costs) are subject to fluctuation for several reasons, including sales volume variation due to weather, variation due to conservation and price elasticity effects as well as growth in revenue from adding new customers. Puget's GRNA proposal would adjust rates to eliminate gas usage and revenue fluctuations due to weather or conservation effects, effectively guaranteeing collection by the utility of the gas margin revenue <u>per customer</u> that was used to set rates.[14] At the same time, PSE would be allowed to collect and retain for its shareholders (not track through rates) steadily increasing margin revenues associated with adding new customers. The combined effect of rate tracking for anticipated declines in usage per customer, while not tracking favorable revenue impacts from adding customers, will assure the utility and its shareholders of stable

[14] The proposed GRNA would guarantee PSE recovery of the gas sales margin "per customer" that was established in the rate case by tracking changes from these values and adjusting future rates. While these changes are labeled "conservation" in Mr. Amen's testimony, they also include all customer demand response to changes in pricing of natural gas (elasticity effects) that occur through purchased gas adjustments.

and increasing future revenue levels while shifting all risks associated with usage per customer declines due to weather and conservation onto customers. Customers would pay higher rates as a result of their collective success in reducing usage and would pay higher rates when weather is mild, while paying lower rates only when sales growth due to severe winter weather is normalized through the GRNA. All of this would occur while PSE gas margin revenues continue to grow as customers are added to the system.

Q. At page 33, Mr. Amen poses the question, "Historically, has PSE experienced a decline in gas use per customer" and then answers, "Yes" with reference to his Exhibit No. ___(RJA-4). What is the significance of this presentation of "per customer" statistical information?

A. On a "per customer" basis, PSE gas delivery volumes are declining, while on a total basis, such volumes are not declining. Total sales volumes are the product of the total number of customers being served as well as the usage "per customer" in any given year. Mr. Amen's testimony is silent with regard to total delivery volume trends or the number of customers being served, instead focusing upon the usage "per customer" data where he can show declines and then argue for exceptional ratemaking remedies.

Q. Have PSE total gas delivery volumes changed much in the past few years as a result of conservation by customers, as suggested by the Company's GRNA testimony?

A. No. According to information contained in the Puget Energy 2005 Annual Report, actual gas volumes delivered in the past five years have been relatively stable, in spite of milder than normal weather in each of the three most recent years:

Year	Therms (millions)	% Colder/(Warmer) Than Average
2001	1039	4%
2002	1047	3%
2003	1025	-6%
2004	1010	-8%
2005	1034	-6%

Source: 2005 Puget Energy Annual Report to Shareholders, pages 138 and 139.

Q. If we look at financial impacts, has PSE actually experienced declining gas margins in recent years, as implied by the testimony of Mr. Amen that discusses weather variability upon sales and generally declining usage due to conservation?

A. No. Mr. Amen is careful in his testimony to discuss usage "per customer", rather than overall volume and margin revenue data. The reality is that PSE gas margin revenues are growing as a result of adding customers and raising rates through traditional rate cases. According to information reported by Puget in its Gas Commission Basis Reports, gas margin revenues from Sales to Customers (less purchased energy costs) have actually grown from $230 million in 1997[15] to about $336 million in the period ended September 2005,[16] an increase of more than $100 million. In this time period, one rate reduction (a one percent revenue decrease in WUTC Docket Nos. UE-951270 and UE-960278) and two rate increases were approved by the Commission. The two rate increases, in Docket Nos. UG-011571 and UG-040460, increased annual margin revenues by $34.3 million in September 2002 and by $25.3 million in March 2005. [17]

Q. Would Mr. Amen's proposed GRNA tariff account <u>fully</u> decouple changes in sales volumes from the margin revenues that PSE would collect in the future?

A. No. PSE does not want to completely decouple sales volumes, but instead wants to retain for shareholders (by not tracking) the favorable effects of sales growth caused by adding new customers, while increasing utility rates for changes in usage on a "per customer" basis. This selective decoupling effect can be seen within Mr. Amen's Exhibit No. ___(RJA-8), which shows an <u>Example of Monthly Deferral Calculation</u> if the GRNA is approved. These calculations illustrate how the Company proposes to keep for its shareholders, as an addition to "Base Line Margin", all of the revenues associated with its calculated "Customer Growth Adjustment".[18] By adding more "Base Line Margin" to the amounts against which actual margin revenue is tracked, the Company ensures that its future revenues will not just be stabilized, but will grow directly in proportion to added new customers.

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[15] Response to WUTC Data Request No. 136; Dec 1997 $409M revenue, less $179 purchased energy.
[16] *Id.* $879M revenue, less $540M purchased energy.
[17] Response to Public Counsel Data Request No. 66.
[18] See ll. 1-11 of Exhibit No. ___(RJA-8).

It is quite possible to design a full decoupling mechanism that would guarantee ultimate recovery of a fixed dollar amount of total margin revenue, but the proposed GRNA does much more than this. Puget's proposed GRNA would not stabilize and decouple margin revenues at a Commission-authorized fixed dollar level, but would instead amplify future revenue growth by increasing delivery prices for conservation effects on "per customer" sales, while letting PSE retain all revenue growth that is caused by adding new customers. In the Company's confidential response to Public Counsel Data Request No. 44, simulation calculations for the proposed GRNA mechanism confirm that PSE intends to retain significant ongoing margin revenue growth from new customers for its shareholders, while also increasing rates through the GRNA mechanism to track anticipated further declines in usage per customer.[19]

Q. If we look backwards, instead of forward, how much higher would PSE's actual growth in gas margin revenues have been in the past five calendar years if the Company's proposed GRNA decoupling rates had been effective for gas utility operations?

A. According to the Company's response to Public Counsel Data Request No. PC-045, the Company would have collected positive additional revenues through the GRNA in every year, above and beyond the historically favorable actual margin trends

[19] The projected "Customer Growth Adjustment" in PSE's Response to PC DR No. 44 indicates anticipated residential margin revenue increases of about **Confidential Begins] ********** [Confidential Ends]**per year along with commercial/industrial customer growth of about **[Confidential Begins] ****** ******* **[Confidential Ends]** per year.

mentioned above, by the following amounts:

Year	GRNA Revenues
2001	$7,110,931
2002	$1,843,666
2003	$1,882,868
2004	$9,750,213
2005	$9,533,081

Source: Attachment A to PSE's Response to Public Counsel Data Request PC-045.

The consistently positive revenue amounts indicate how the proposed GRNA would favor shareholders, by charging customers higher rates to make up for declining usage per customer, while ignoring the fact that margin revenues in total are growing due to customer growth.

Q. Does traditional ratemaking involve the measurement of overall gas delivery volumes, in a manner that recognizes <u>both</u> the number of customers being served, as well as the recently declining usage "per customer" that Mr. Amen has chosen to focus upon?

A. Yes. This holistic test year approach under traditional regulation is critically important to the establishment of just and reasonable utility rates, because it accounts for <u>all</u> of the elements of the revenue requirement, including the number of customers being served in the test year, their usage levels, and all of the investment and expenses incurred to provide gas delivery services to such customers within the test year. The reasonableness of resulting utility rates is heavily dependent upon a balanced review of all ratemaking elements at a common point in time. Departures from the traditionally balanced test year approach should only be implemented when compelling facts justify upsetting this balance by establishing special cost trackers or accounting deferrals subject to strictly applied regulatory criteria.

Q. PSE may argue that, because the Company incurs additional investment and expenses when it connects and serves new customers, the Commission should ignore the increasing gas delivery levels and revenues caused by adding new customers and adopt rate tracking for only declining usage "per customer". Would this be reasonable?

A. No. As noted in my prior response, traditional regulation involves an intensive review of <u>all of the elements</u> of the revenue requirement within the established test year, including all costs associated with adding and serving new customers. It would be inappropriate to assume that PSE realizes no financial benefit from customer growth between rate cases that can help to mitigate conservation effects. It would also be inappropriate, in my view, to assume that PSE is unable to deploy new technology or improved methods of operation to exploit productivity gains useful in mitigating cost increases or ratepayer conservation effects.[20] I would encourage the

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[20] In its response to Public Counsel Data Request No. 39, PSE states, "The prefiled direct testimony of many of PSE's witnesses in this proceeding identify a variety of technological innovations, efficiency measures and best practices that PSE has undertaken over the past several years to improve productivity and reduce the cost associated with providing regulated utility services in Washington, including, for example, the prefiled direct testimonies of: Kimberly J. Harris, Exhibit No. ___(KJH-1T), Susan McLain, Exhibit No. ___ (SML-1CT); Eric M. Markell, Exhibit No. ___ (EMM - 1CT); Roger Garratt, Exhibit No. ___(RG-1HCT); David E. Mills, Exhibit No. ___ (DEM- 1CT); Bertrand A. Valdman, Exhibit No. ___ (BAV-1CT); Donald E. Gaines, Exhibit No. ___ (DEG-1CT); and Tom M. Hunt, Exhibit No. ___ (TMH-1T)."

Commission to not accept any unproven assumptions regarding whether or not customers added to PSE's gas delivery system between rate cases are financially harmful or beneficial to the Company.

Q. In a previous section of your testimony you described the incentives created by regulatory lag. Has PSE proposed the new GRNA tariff out of concern that regulatory lag may work against the interests of shareholders in the future without such tracking?

A. Yes. With respect to the GRNA, Mr. Amen states at page 27 that PSE is proposing this ratemaking mechanism for "three important and interrelated reasons". He then describes concerns with accurate forecasting of gas volumes that will be used by customers in future periods, with declining future gas volumes due to energy efficiency programs for customers, and with the impact of weather on PSE's financial condition. In subsequent testimony, Mr. Amen explains that sales volume fluctuations due to weather cause earnings variability,[21] while a declining long-term trend in weather-adjusted usage per customer is also discernable due to conservation.[22]

The weather impact upon actual sales volumes in any given year can be significant, but over many years sales will tend to gravitate toward average or "normal" levels. On the other hand, any longer term conservation trends expose the Company to regulatory lag between rate cases, when declining usage revenues due to

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[21] Direct Testimony of Ronald J. Amen, Exhibit No. ___ (RJA-T1, pp. 30-32 and 36-37) and Exhibit No. ___(RJA-4).

[22] *Id.* p. 33 and Exhibit No. ___ (RJA-5).

conservation effects cannot be readily translated into rate increases under traditional ratemaking methods. Any ongoing conservation effects among existing customers may very well be offset by productivity gains that reduce expenses or with new revenues from added customers that are not accounted for in the proposed GRNA.

Q. In your opinion, is the expected financial impact of PSE gas customer conservation and weather fluctuation substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases?

A. No. In the back-casting analysis performed by PSE, the annual financial impacts of the GRNA if applicable in 2001 through 2005 would not have exceeded $10 million in any year. When reduced for income taxes at the 35 percent statutory Federal rate, these amounts represent about 4 percent of Puget Energy's reported 2005 consolidated net income.

Q. In a previous section of testimony, you described the incentives created by regulatory lag. Does regulatory lag serve to discourage utility management from actively promoting conservation of energy?

A. Not significantly. Utility shareholders will generally benefit when sales volumes increase between test periods and are harmed when sales decline. Sales volumes are influenced by the addition of new customers and by changes in usage levels of existing customers, suggesting that utility promotion of energy conservation by existing customers might be actively discouraged by management. However, in this era of high-priced natural gas, conservation measures are necessary to attract new customers and to retain existing gas utility customers that may otherwise elect alternative energy sources such as electricity when appliances are being installed or replaced. PSE has little choice in this environment but to promote the efficient use of natural gas.

As noted at page 33 of Mr. Amen's direct testimony, "PSE's customers have reduced their gas consumption, not unlike other gas customers through the U.S. [footnote omitted], primarily by the use of increased efficiency gas appliances and tighter, more energy efficient homes as a result of improved insulation and window products and higher building code standards." Clearly, conservation in gas usage is a long-term phenomenon, driven by replacement of gas burning appliances with ever more efficient newer technology as well as consumer demand response to higher commodity prices. The Commission should, in my opinion, expect PSE to provide energy conservation programs for its customers as a necessary element of its public service obligation.

Q. If the Commission is concerned about the potential disincentive to utility management to promote reduced gas consumption between rate cases, are there alternatives to the GRNA decoupling approach that can be employed?

A. Yes. Regulators have responded to such "disincentive" concerns in the design of utility demand side management ("DSM") programs by approving shareholder incentives or compensation for DSM-caused lost margins within such programs. By carefully targeting such incentives, it is possible to match the additional compensation to shareholders to actual achievements under DSM measures that are deployed, rather than globally shifting all risks associated with sales declines from shareholders to customers.

Q. Would a properly targeted regulatory incentive to fully compensate shareholders for only the margin dollars actually lost to utility conservation programs need to be scoped as broadly as the GRNA mechanism proposed by PSE?

A. No. The GRNA provides compensatory rate increases for <u>all</u> experienced usage per customer reductions, whether the reductions are caused by utility conservation programs, routine replacement of older appliances, turnover in housing stock with more efficient designs or simple price elasticity demand responses of consumers. In fact, utility sponsored conservation programs appear to produce only a modest impact on anticipated sales volumes and margin revenues. In its response to NWEC Data Request No. 033, PSE stated that, "…a gas energy efficiency stretch goal of 4.2 million therms was set for 2006 and 2007 in collaboration with the Conservation Resources Advisory Group." Even if we assume that PSE achieved <u>all</u> of its "stretch" goals through conservation programs over these two years, the resulting 2.1 million annual therms of conservation demand reduction is only about 0.2 percent of PSE's annual sales that exceed 1 billion therms. Such a small impact upon annual sales from utility sponsored conservation efforts is insufficient cause to introduce a complex new rate tracker that addresses all variations in usage per customer, most of which variation is likely caused by other factors including weather, price elasticity and continuing turnover of old appliances and housing.

Q. Can the input values and computations involved in administering the Company's proposed GRNA tariff be readily audited and verified through expedited regulatory reviews?

A. Probably not. In his Exhibit No.__(RJA-8), Mr. Amen outlines the monthly calculations involved in calculating current accounting deferrals associated with the GRNA. The Company's proposed tariff (Exhibit No. ___RJA-9) for the GRNA adds considerable complexity to these monthly calculations by adding monthly accrued interest to deferred balances for each of the applicable rate schedules and then calculating the "Rate" to be charged by reference to tables of usage (Section 5) and meter count (Section 6) values shown in the tariff. For these calculations to be readily audited on an expedited basis, Staff and other concerned parties would need to dedicate significant resources to the analysis of cumulative deferrals, the annual re-determination of this rate and the required true-up of prior year over or under-recoveries.

Q. Please summarize your specific recommendations regarding PSE's proposed Depreciation Tracker and GRNA mechanism.

A. For all of the reasons explained in my testimony, I recommend the Commission reject PSE's proposed Depreciation Tracker and GRNA mechanism.

Q. Does this conclude your testimony at this time?

A. Yes.