CAC EXHIBIT B (BEB)

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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| PETITION OF PSI ENERGY, INC FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE; FOR APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND OF RULES AND REGULATIONS APPLICABLE TO SUCH RATES AND CHARGES; FOR THE AUTHORITY TO REFLECT ITS QUALIFIED POLLUTION CONTROL PROPERTY AND OTHER NEW PLANT AND EQUIPMENT IN ITS RATES AND CHARGES; FOR APPROVAL OF ITS IMPLEMENTATION OF THE FEDERAL ENERGY REGULATORY COMMISSION'S SEVEN-FACTOR TEST; FOR APPROVAL OF VARIOUS RATE TRACKING MECHANISMS, INCLUDING A PROPOSED MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR MANAGEMENT COST ADJUSTMENT RIDER AND CONTINUED USE OF A PURCHASED POWER TRACKING MECHANISM; AND FOR APPROVAL OF RELATED ACCOUNTING TREATMENT AND DEPRECIATION RATES AND OTHER ACCOUNTING RELIEF RELATIVE TO ITS BUSINESS. | ) | CAUSE NO. 42359 |

Testimony of

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Synapse Energy Economics, Inc.

Prepared on Behalf of

THE CITIZENS ACTION COALITION OF INDIANA

PUBLIC VERSION

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## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME, BUSINESS POSITION AND ADDRESS.**

A. My name is Bruce Edward Biewald. I am president of Synapse Energy Economics, Inc., 22 Pearl Street, Cambridge, Massachusetts, 02139.

**Q. PLEASE DESCRIBE YOU EMPLOYMENT, QUALIFICATIONS, AND EXPERIENCE?**

A. I am president and owner of Synapse Energy Economics, Inc., a consulting company specializing in economic and policy analysis of the electricity industry, particularly issues of restructuring, market power, electricity market prices, consumer protection, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power. I graduated from the Massachusetts Institute of Technology in 1981, where I studied energy use in buildings. I was employed for 15 years at the Tellus Institute, where I was Manager of the Electricity Program, responsible for studies on a broad range of electric system regulatory and policy issues. I have testified on energy issues in more than eighty regulatory proceedings in twenty-five states and two Canadian provinces. I have co-authored more than one hundred reports, including studies for the Electric Power Research Institute, the U.S. Department of Energy, the U.S. Environmental Protection Agency, the Office of Technology Assessment, the New England Governors' Conference, the New England Conference of Public Utility Commissioners, and the National Association of Regulatory Utility Commissioners. My papers have been published in the *Electricity Journal*, *Energy Journal*, *Energy Policy*, *Public Utilities Fortnightly* and numerous conference proceedings, and I have made presentations on the economic and environmental dimensions of energy throughout the U.S. and internationally. I also have consulted for federal agencies, including the Department of Energy, the

Department of Justice, the Environmental Protection Agency, and the Federal Trade Commission. Details of my experience are provided in Exhibit BEB-1.

**Q. HAVE YOU TESTIFIED PREVIOUSLY IN INDIANA?**

A. Yes. I most recently testified before the Commission in July, 2002, regarding a proposed settlement of a pending NIPSCO rate investigation. Previously, I testified before the Commission regarding NIPSCO system reliability and excess capacity in Cause No. 38405 in November, 1986. I made a presentation regarding stranded costs in the Commission's Forum on Electric Industry Competition in November, 1996. I also made presentations regarding various aspects of electric utility restructuring before the Indiana Energy Conference in October, 1996 and the Regulatory Flexibility Committee of the Indiana General Assembly in September, 1997. I also prepared and filed testimony regarding the proposed termination of the operating agreement between PSI Energy, Inc. and Cincinnati Gas & Electric Company in Cause No. 41952 in June, 2001, but the case was settled before my testimony was admitted.

**Q. ON WHOSE BEHALF DO YOU APPEAR IN THIS PROCEEDING?**

A. On behalf of the Citizens Action Coalition of Indiana, Inc.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The Citizens Action Coalition has asked me to review aspects of the Company's rate proposal that may unfairly allocate risk to its customers.

**Q. PLEASE SUMMARIZE YOUR KEY CONCLUSIONS AND RECOMMENDATIONS.**

A. My conclusions are as follows:

- The scope and number of the Company's existing and proposed rate adjustment trackers is large in comparison to similar regulated utilities. These trackers provide significant risk reduction benefits to the Company.

- Based on the information that the Company has provided, I project the net cost or credit to customers of the Summer Reliability Tracker and conclude that, contrary to the Company's claims, the tracker is likely to result in a net cost to customers beginning in 2004.
- The system for accounting and tracking of transactions is complex and prone to abuse.
- The Company's proposed NOx Emission Allowance (EA) tracker differs from its existing SO2 tracker in that is allows the Company to retain a portion of any profits it receives through its NOx EA transactions. This represents a potentially inappropriate incentive for the Company, as PSI should not be allowed to gain from EA sales made possible through NOx compliance costs that it is fully recovering from customers.
- The trackers reduce or eliminate the incentive for the Company to manage costs and risks associated with the tracked costs, even though the Company is in a better position than its customers to manage those costs and risks.
- The inclusion of the previously unregulated merchant plants into PSI's rate base provides additional risk reduction benefits to Cinergy's shareholders by assuring them of recovering through PSI's retail rates the cost of its holding company's unprofitable unregulated investments.
- Cinergy actively analyzes and manages risks to shareholders, but neither PSI nor Cinergy adequately analyzes or manages risks to regulated customers.
- Cinergy and PSI have made some, but very limited progress toward managing environmental risks, diversifying the resource mix, and realizing attractive opportunities to invest in efficiency and renewable generating sources.

Based on these conclusions, my recommendations to the Commission are as follows:

- The Commission should disallow the Summer Reliability Tracker's off-system sales profit sharing mechanism and require the Company to credit all such profits to customers. The Company should also establish a monitoring process independent of its holding company to verify that PSI's off-system sales activity is optimized for the benefit of its customers.

- The Commission should open a sub-docket to more carefully review and thoroughly audit the Company's use of the Post Analysis Cost Evaluation model and the corresponding issues pertaining to the Joint Generation Dispatch Agreement.
- The Commission should reject the net revenue allocation scheme of the Company's proposed NOx Emission Allowance tracker and require the Company to allocate 100 percent of net gains and losses from allowance transactions to customers.
- The Commission should consider the risk reduction effects of the Company's existing and proposed trackers and of the inclusion of merchant plants in the Company's base rates in determining an appropriate return on equity.
- PSI should be required to conduct an analysis of options to further mitigate its environmental risks, by diversifying its resource mix, by retrofitting additional emission controls to existing facilities, by increasing its supply-side efficiency, by investing in a comprehensive set of demand-side management programs, and by developing renewable generating resources in its service territory. The Company should be required to pursue those resource options that are found to be attractive in that analysis.

**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A. I begin my testimony with a general discussion of risk exposure and rate of return on common equity. I present the results of my rate adjustment tracker analysis and relate them to the Company's risk exposure and proposed rate of return on equity. In the following section, I examine the Company's proposed Summer Reliability Tracker and provide a projection of the tracker's cost to customers that contradicts the Company's expectation that the tracker will result in a credit to customers in the initial years of its existence. I also examine the reasonableness of the profit-sharing mechanism of the tracker, and provide my opinion about the overall equity of the tracker. I follow this with a discussion of the issues surrounding the Company's Post Analysis Cost Evaluation and their implications for the Company's Joint Generation Dispatch Agreement.

Next, I examine how the Company's proposed NOx Emission Allowance tracker may improperly allocate net gains and losses from EA transactions between the Company and its customers. I also observe that the tracker will further reduce the Company's exposure to environmental compliance risks. I then proceed to a discussion of the declining value of Cinergy's merchant plants prior to their transfer to PSI, and the risk allocation implications of their inclusion in PSI's rate base. Finally, I examine whether PSI may have imprudently managed its environmental risks and discuss the value of energy efficiency and renewable energy investments in reducing PSI's vulnerability to these risks.

## II. <u>RISK EXPOSURE AND RETURN ON EQUITY</u>

**Q. TO WHAT FORMS OF RISK IS A REGULATED UTILITY COMPANY TYPICALLY EXPOSED TO?**

A. Regulated utility companies are exposed to many different forms of risk, including weather, financial, economic, environmental, and regulatory risks.

**Q. HOW ARE THE COMMON SHAREHOLDERS OF A REGULATED UTILITY COMPENSATED FOR EXPOSURE TO THESE RISKS?**

The Return on Equity (ROE) is intended to reasonably compensate common shareholders for exposure to these risks. The Company is requesting a Return on Equity of 11.5 percent.[1] In determining whether the Company's requested ROE is excessive, the Commission should consider the following:

- The risk reduction effect of the Company's existing and proposed trackers and pre-approved costs; and
- If the Commission's pre-approval of the Company's merchant plant acquisition has effectively shifted from Cinergy to PSI customers most of the risks associated with the investment in those plants.

[1] Prefiled Case-in-Chief testimony of Roger A. Morin, page 4, line 10.

**Q. WHAT RATE ADJUSTMENT TRACKERS ARE CURRENTLY INCLUDED IN THE COMPANY'S REVENUES?**

A. The following table presents a list of the riders that were in effect in April 2003[2], along with the per books jurisdictional revenue attributable to each during the test year ending September 30, 2002. The information in this table was obtained from Schedule C-3.4 in Mr. Farmer's Petitioner's Exhibit X-8.

| Rider No. | Description | Per Books Amount (000s) |
|---|---|---|
| 60 | Fuel Cost Adjustment | - |
| 62 | Qualified Pollution Control Property | $4,752 |
| 63 | Emission Allowance | $16,111 |
| 66 | DSM Recovery of On-Going Expense | $8,806 |
| 67 | Recovery of Pre-approved Purchased Power Costs | $22,365 |
| Total | | $52,034 |

In addition to these trackers, the Company also has an environmental Construction Work in Progress (CWIP) Tracker that generated $27.8 million in the test year.[3] Including this amount to the total tracker revenue in Table A would increase the total revenue to $79.8 million.

**Q. HOW DOES THE COMPANY'S TOTAL TRACKER REVENUE COMPARE TO ITS RETAIL OPERATING REVENUES DURING THE TEST YEAR?**

A. The Company's pro forma operating revenues under current rates, exclusive of all trackers, is $1,251.2 million.[4] Netting out fuel costs, which the Company is allowed to fully recover, and adding in the $79.8 million tracker revenue, results

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[2] Petitioner's Exhibit BB-1 (Bailey). The rate adjustment mechanisms under consideration in this proceeding are sometimes referred to as "riders" and sometimes as "trackers." I will use the two terms interchangeably.

[3] Petitioner's Exhibit C-5 (JPS-5) (Steffen), line 2, column G.

[4] Petitioner's Exhibit C-5 (JPS-5) (Steffen), line 2, column F.

in operating revenues of $952.7 million. Thus, the Company's total tracker revenue is equivalent to 8.4% of its operating revenue during the test year.

If we include the Company's pro forma fuel costs in the calculation of tracked revenue, then $378.3 million of the Company's $1,331.0 million of operating revenues, or 34.4%, are "tracked" under the Company's current rates.

These numbers, while significant, do not paint the full picture of the Company's ability to recover its costs. The vast majority of the Company's "untracked" operating expenses are not subject to the high levels of volatility and uncertainty that characterize its "tracked" expenses. The Company is virtually assured of recovering these more predictable expenses through the return on its rate base. As explained in greater detail below, the Company's trackers enhance its ability to recover all of its costs by greatly reducing the possibility that it will not be able to recover costs of a volatile nature in a timely manner.

**Q. WHAT ADDITIONAL TRACKERS IS THE COMPANY REQUESTING APPROVAL FOR IN THIS RATE CASE?**

A. In addition to the above trackers, the Company is seeking approval for the following proposed trackers, which are described in the prefiled testimonies of Kent K. Freeman (Exhibit Z) and Stephen M. Farmer (Exhibit CC):

<u>Rider No. 68</u>

MISO Tracker to track Midwest Independent Transmission System Operator related management costs.

<u>Rider No. 69</u>

NOx Emission Allowance Tracker to track the sales and purchases of NOx Emission Allowances.

<u>Rider No. 70</u>

Summer Reliability Tracker to track summer purchased power costs, PowerShare costs, and off-system sales profits. This tracker is intended to effectively replace Rider No. 67.

**Q. HOW DO THE COMPANY'S TRACKERS AFFECT ITS EXPOSURE TO RISK?**

A. By passing through a substantial portion of its operating costs to retail rates, the Company's rate tracking mechanisms effectively reduce its shareholders' exposure to risk in that they (1) reduce regulatory lag; (2) allow certain significant categories of costs (e.g. environmental costs) that increase to be put into rates without consideration of other, related categories of costs (e.g. cost of capital) that decrease; (3) tend to defer general rate cases, with their attendant risks and costs; (4) tend to decrease the scope and detail of regulatory review of tracked costs compared to a general rate case.

Furthermore, such riders can, in many situations, greatly reduce volatility of net earnings on a monthly, quarterly and annual basis, by virtue of the fact that they eliminate or significantly reduce the likelihood of failing to recover the costs associated with particularly volatile line items. Such a reduction of volatility in net earnings, *per se*, can constitute a material reduction in the financial risk of the firm as a whole from the perspective of shareholders and is of significant value to them, more generally.

**Q. WHAT ARE THE POTENTIAL BENEFITS TO RATEPAYERS OF THE COMPANY'S REDUCED VOLATILITY AND RISK EXPOSURE?**

A. As the Company has noted several times in its testimony, reduced volatility and risk exposure may have a positive impact on the Company's credit rating, hence reducing the cost of capital for both equity and debt. This will tend to reduce retail electric rates. However, several other factors also affect electricity rates, including the Company's approved return on equity. If the Company's approved ROE does not account for the risk reduction effects of its trackers and other risk reduction measures which I discuss later in my testimony, then customers may be required to subsidize excessive shareholder earnings by paying inordinately high rates.

**Q. HOW DO THE NUMBER AND SCOPE OF THE COMPANY'S EXISTING AND PROPOSED TRACKERS COMPARE WITH THOSE OF OTHER ELECTRIC UTILITY COMPANIES?**

A. Roger A. Morin's prefiled testimony explains how he calculated the company's proposed return on equity by reference to a peer group of 13 comparable investment-grade vertically integrated electric utilities. These utilities are listed in Petitioner's Exhibit G-11 (RAM-11). Exhibit BEB-2 presents a comparison of the rate adjustment trackers included in the general rate schedules of each of the 13 utilities in Petitioner's Exhibit G-11, as well as PSI's existing and proposed trackers. These 14 utilities own 26 regulated electric generation, transmission, and distribution companies in 16 separate states with varying degrees of deregulation and regulatory oversight. The average number of trackers employed by each of the 26 companies is 2.12.[5] Across the 14 utilities, the average is 2.35 trackers per utility. With six trackers,[6] PSI has the highest number among the 26 utility companies, and is one of only two companies (Alabama Power is the other) that have trackers for perhaps the four most significant cost categories that are commonly tracked: fuel adjustment, purchased power, environmental cost recovery, and emission allowances.

**Q. WHAT DOES THIS SUGGEST ABOUT PSI'S EXPOSURE TO RISK RELATIVE TO ITS INDUSTRY PEERS?**

A. The large number of PSI's rate adjustment trackers relative to its industry peers suggests that the Company is relatively well protected against many risks to which other utilities are often exposed.

**Q. DON'T THE UNIQUE REGULATORY AND BUSINESS CIRCUMSTANCES OF EACH UTILITY HINDER THE USEFULNESS OF SUCH A COMPARISON?**

A. Although regulatory conditions do differ from state to state, there are a number of risks that are almost universally applicable to regulated utilities. As mentioned above, perhaps the most significant of these are fuel costs, purchased power capacity costs, and environmental compliance costs, including the cost of

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5 Rather than base my comparison on the absolute number of trackers that each company has, I have chosen to identify trackers by category. Hence, the absolute number of trackers that Company has does not necessarily match its categorical number. In the case of PSI, the Company has an existing SO2 emission allowance tracker and has proposed a NOx emission allowance tracker. Because these two trackers both address emission allowances, I have grouped them together and counted them as a single tracker for the purposes of my analysis.

6 Again, this is the categorical, rather than absolute, number of trackers that PSI currently employs and is proposing.

purchasing emission allowances. These are the uncertainties that rate adjustment trackers are intended to account for and minimize,[7] and I believe that a tracker-based comparison can serve as an indicative measure of a company's protection against risk.

**Q. IN YOUR VIEW, WOULD THE COMPANY'S PROPOSED RETURN ON EQUITY BE APPROPRIATE IF ITS PROPOSED TRACKERS ARE APPROVED?**

A. The magnitude and number of PSI's existing trackers and the magnitude of its proposed trackers, particularly the Summer Reliability Tracker which I will discuss later in my testimony, greatly reduce the Company's exposure to several different types of risk. A reasonable return on equity for PSI would account for the risk reduction effect of the Company's rate tracking mechanisms.

## III. SUMMER RELIABILITY TRACKER

**Q. UNDER THE COMPANY'S PROPOSED SUMMER RELIABILITY TRACKER, HOW ARE THE COSTS OF PURCHASED POWER AND THE PROFITS FROM OFF-SYSTEM SALES SHARED BETWEEN THE COMPANY AND ITS CUSTOMERS?**

A. As explained in the pre-field Case-in-Chief testimony of Douglas F. Esamann, under the proposed tracker, 100 percent of summer purchased power costs are borne by customers. Off-system sales profits are assigned to customers in the following manner: 100 percent of off-system sales profits during the summer, and 25 percent of profits during the non-summer months (October to May). During the non-summer months, 75 percent of profits from off-system sales are retained by the Company. Assuming replication of test-year experience, this arrangement would result in a 50/50 sharing of profits between PSI customers and its holding company.

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[7] In Page 25, Line 22, of Steven M. Fetter's Prefiled Case-in-Chief testimony, Mr. Fetter states, in reference to fuel and purchased power trackers, "These mechanisms mitigate a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations."

**Q. HAS THE COMPANY PROVIDED PROJECTIONS FOR SUMMER PURCHASED POWER COSTS?**

A. Yes. The Company provided data request response NUCOR/PSI-2.7-A, which contains projected summer purchased power costs from 2003 to 2007 (see attached Exhibit BEB-3).

**Q. WHAT AMOUNT DOES THE COMPANY EXPECT TO SPEND ON PURCHASED POWER?**

A. NUCOR/PSI-2.7-A indicates that, between 2003 and 2007, the Company projects that it will need to purchase 1,237,264 MWh at a total cost of $97,763,843.

**Q. DOES THE COMPANY INDICATE THE PORTION OF THESE COSTS THAT ARE INCLUDED IN THE SUMMER RELIABILITY TRACKER?**

Yes. The same data request response indicates that the Tracker portion of these costs is $81,012,312. Averaged over the five-year projection period, this is equivalent to approximately $16.2 million per year.

**Q. ARE THE COMPANY'S PURCHASED POWER PROJECTIONS REASONABLE?**

A. There is reason to believe that the Company's purchased power projections are conservatively low. PSI has contracts with a number of large wholesale customers that are due to expire between 2003 and 2007. The Company's Base Case Load Forecast upon which the above purchased power projections are based assume that these wholesale customers do not enter into new supply contracts with PSI. As noted in page 12 of Diane L. Jenner's prefiled case-in-chief testimony, this assumption provides a conservatively low view of PSI's future load. If PSI continues to serve all of its current wholesale load, the Tracker portion of summer purchased power costs would be approximately $65.6 million in 2007 – compared to about $13.6 million using the assumption that PSI does not renegotiate any new wholesale contracts.[8] This serves to illustrate that the projected cost of purchased power during the summer months is heavily dependent on the Company's expected load.

[8] From NUCOR/PSI-2.7-A

**Q. WHAT OTHER UNCERTAINTIES AFFECT PSI'S PROJECTED LOAD AND PURCHASED POWER REQUIREMENTS?**

A. As identified by the Company, the other primary uncertainties with respect to PSI's projected load and purchased power requirements are whether: PSI can cost-effectively implement new and enhanced DSM programs; PSI will be able to increase customer participation in PowerShare programs; PSI's interruptible customers will switch back to firm service once their current contracts expire; and PSI's reserve margin criteria should be changed to 17% rather than 15%.[9]

**Q. HOW DOES EACH OF THESE UNCERTAINTIES AFFECT THE COMPANY'S PROJECTED LOAD AND PURCHASED POWER REQUIREMENTS?**

A. Increases in demand-side resources and customer participation in peak load management programs will have the effect of decreasing the actual load relative to the Base Case Load forecast, thus reducing the Company's need for purchased power. If the Company's interruptible contracts are not renewed, the actual load will be higher relative to the Base Case, and the Company's purchased power needs will be greater. Under a 17 percent reserve margin requirement, the actual load does not change relative to the forecast, but purchased power requirements increase by 43 percent over the eight-year period from 2003 to 2010.

**Q. WHAT ARE THE LOW AND HIGH-END ESTIMATES OF THE COMPANY'S PROJECTIONS FOR PURCHASED POWER REQUIREMENTS?**

A. Data from Petitioner's Exhibit W-2 (DLJ-2) indicate that the Company's projected total purchased power requirements between 2003 to 2010, inclusive, range from a low of 1,658 MW to a high of 5,202 MW. The low-end estimate represents a 31 percent reduction from the Base Case and is based on the aggressive assumption that RTP/CallOption demand-side resources remain at high 2001 levels. The high-end estimate, which exceeds the Base Case level by 117 percent, assumes that PSI continues meeting all of its current wholesale customer load through 2010.

[9] The uncertainty over PSI's reserve margin criteria, particularly the component for unscheduled outages, is discussed on pages 14-15 of Ms. Jenner's pre-filed testimony.

**Q. IN YOUR OPINION, DOES THE COMPANY'S BASE CASE LOAD FORECAST PROVIDE A REASONABLE AND ACCURATE ESTIMATE FOR DETERMINING PURCHASED POWER REQUIREMENTS?**

A. I believe that the Company's Base Case load forecast may be unreasonably low. The forecast assumes that PSI does not renegotiate any new wholesale customer contracts after its current contracts expire, and it assumes that *all* of its current interruptible load contracts are renewed. These are very conservative assumptions, and in my view, it is more likely that the Company would continue to meet at least some portion of its existing wholesale customer load and would find that some interruptible load customers fail to renew their contracts and become firm customers. For instance, Ms. Jenner's pre-filed Case-in-Chief testimony states that "recent experience in other regions has shown that actual interruption has caused some interruptible customers to switch back to firm service" (page 14, line 10).

Based on these factors, it appears that the Company's Base Case load forecast should be adjusted to reflect less conservative assumptions about its projected load for purposes of projecting summer purchased power. This would result in a higher level of projected summer purchased power.

**Q. HAS THE COMPANY PROVIDED PROJECTIONS FOR PROFITS FROM OFF-SYSTEM SALES?**

A. Yes. Page 5 of Ms. Jenner's pre-filed Case-in-Chief testimony contains a chart with estimated monthly off-system sales profits from re-dispatch analyses from October 2002 through September 2003. The total profits for the one-year period are approximately $17.9 million.

**Q. HAS THE COMPANY PROVIDED OFF-SYSTEM SALES PROFITS PROJECTIONS BEYOND SEPTEMBER 2003?**

A. To my knowledge, the Company has not provided any such projections in its pre-filed testimony or in response to data requests.

**Q. IN HIS PREFILED TESTIMONY AND HIS CROSS EXAMINATION BEFORE THE COMMISSION ON JUNE 9, 2003, MR. ESAMANN MADE REFERENCE TO THE EXPECTATION THAT THE NET IMPACT OF THE SUMMER RELIABILITY TRACKER WOULD CONSTITUTE A CREDIT RATHER THAN A CHARGE TO THE COMPANY'S CUSTOMERS. HAS THE COMPANY PROVIDED COST ESTIMATES TO SUPPORT MR. ESAMANN'S EXPECTATION REGARDING THE SUMMER RELIABILITY TRACKER?**

Yes. In response to OUCC Data Request 101, the Company provided the following estimate of the projected credit for the Summer Reliability Tracker annual amount:

| Component | Dollars (000) |
|---|---|
| Estimated profits from Off System sales (1) | [redacted] |
| Reliability Purchases (demand component) (2) | [redacted] |
| PowerShare® Costs (Call & Quote Option) (3) | [redacted] |
| Estimated Credit | [redacted] |

(1) Based on a comparison of two ProMod Runs Twelve Months ended September 30, 2003. Base Case run (i.e. Native plus off-system sales) minus Native Case run.
(2) Demand portion of reliability purchases (subject to Commission approval).
(3) Pro Forma level per Petitioner's Exhibit AA-3 (JRB-3)

**Q. IN YOUR VIEW, IS THIS A REASONABLE ESTIMATE OF THE ANNUAL CREDIT FOR THE SUMMER RELIABILITY TRACKER?**

A. While this may be a reasonable estimate for the credit from the tracker in the 12-month period ending September 2003, other data that the Company has provided actually implies that the tracker will result in net costs to its customers in the years following 2003. Exhibit BEB-4 presents confidential data response CAC/PSI-2.8-J. [redacted] In 2004, the Company projects that it will need to make [redacted] of summer power purchases.[10] In 2005, the cost of projected summer power purchases rises to just under [redacted]. The credit to retail customers from off-systems sales profits in Ms. Jenner's redispatch analysis was [redacted]. [redacted] This data is presented in graphical form in confidential Exhibit BEB-5.

**Q. IN HIS TESTIMONY, MR. ESAMANN STATES THAT THE PROPOSED PROFIT SHARING MECHANISM IN WHICH PSI RETAINS 75% OF NON-SUMMER OFF-SYSTEM SALES PROFITS WOULD PROVIDE THE COMPANY WITH INCENTIVE TO MAXIMIZE ITS OFF-SYSTEM SALES PROFITS. PLEASE COMMENT ON THE APPROPRIATENESS OF THIS INCENTIVE.**

A. I do not believe that such a profit sharing mechanism as proposed in the Company's tracker is either proper or necessary. As a regulated utility, PSI is bound to provide quality electricity service at the lowest possible cost to its customers. In exchange, it receives a state-sanctioned monopoly within its service territory and charges state-sanctioned rates which provide it with the opportunity to earn a reasonable rate of return on its investment in providing service. As a result, the Company should not require any other motive to optimize its operations for the benefit of its customers other than its legal mandate to do so. In claiming that additional profit in the form of an incentive is necessary to maximize the cost efficiency of its resources, the Company is subverting its responsibility to its customers as a regulated utility.

**Q. IS THERE A SINGLE IDEAL APPROACH TO UTILITY INCENTIVES?**

A. No. In many situations utility rates are set simply to recover prudently incurred costs, and regulators hope or assume or enforce through prudence reviews that the regulated utility will fulfill its obligations to provide reliable service at the lowest reasonable cost. A utility subject to this sort of "traditional regulation" would,

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[10] Based on wholesale forwards from 3/19/03.

presumably, attempt to minimize its overall costs of providing service, subject to various constraints and risk-related considerations. This would involve dispatching the system economically, minimizing fuel and purchased power costs, and maximizing net revenue from off-system sales.

In some regulatory contexts explicit performance incentive systems are put in place to specifically penalize (or, conversely, reward) particularly poor (or good) utility performance. Synapse Energy Economics, Inc. prepared a report entitled "Performance-Based Regulation in a Restructured Electric Industry" for the National Association of Regulatory Utility Commissioners. In that report, we analyzed experience with existing performance-based regulation (PBR) programs and potential designs of future PBR programs. We concluded that the specifics of a PBR approach should naturally depend upon the context and the objectives in any particular situation. In other words, there is no single ideal approach to incentives. But such approaches should not result in windfall profit opportunities for investors at the expense of customers.

**Q. DO THE TRACKERS REDUCE UTILITY INCENTIVES TO REDUCE COSTS?**

A. Yes. "Traditional rate regulation" involves occasional rate cases with cost increases or decreases between rate cases borne by the shareholders. To the extent that trackers and adjustment clauses eliminate the regulatory lag between rate cases, they also reduce the associated incentives to the Company to increase revenues or reduce costs during those periods.

**Q. CAN YOU COMMENT SPECIFICALLY ON PSI'S PROPOSED INCENTIVE APPROACH FOR OFF-SYSTEM SALES?**

A. Yes. The Company's proposal is for 100% of off-system sales profits in the summer to be credited to customers, and for 25% of off-system sales profits in other months to be credited to customers, with shareholders benefiting from 75% of the off-system sales profits in the non-summer months. In my view the 75% "incentive" to the Company for non-summer off-system sales is excessive. It is unreasonable and unjustified.

Moreover, incentive approaches can have unintended consequences, and incentive frameworks with large discontinuities are particularly prone to problems. PSI (or its affiliates hopefully acting on its behalf) makes decisions that influence PSI's summer resource balance and costs. They also make decisions that influence PSI's annual resource balance and costs. If a resource decision (e.g., to add a baseload resource rather than a peaking resource) will result in a large increase in PSI's non-summer off-system sales revenue (which shareholders would keep 75% of under the Company's proposal) but would increase costs that are passed through to customers, how would that be evaluated? A very specific targeted incentive of this type could serve to undermine the overall objective of low net costs of serving regulated customers.

**Q. DID MR. ESAMANN ADEQUATELY ADDRESS THIS ISSUE IN HIS ORAL TESTIMONY BEFORE THE COMMISSION?**

A. No. Under cross-examination during his testimony before the Commission on June 9, 2003, Mr. Esamann failed to adequately address concerns regarding the issue of PSI's split incentive approach to off-system sales profits. Instead, Mr. Esamann chose to refocus attention on how the profit-sharing mechanism is intended to produce an equal sharing of off-system sales profits. Exhibit BEB-6 presents the relevant excerpt from the transcript of the June 9, 2003 hearing.

**Q. IN YOUR OPINION, DOES THE SUMMER RELIABILITY TRACKER EQUITABLY DISTRIBUTE THE COSTS OF PURCHASED POWER AND THE PROFITS FROM OFF-SYSTEM SALES BETWEEN THE COMPANY AND ITS CUSTOMERS?**

A. I do not believe that the Summer Reliability Tracker would equitably distribute the costs and profits from these off-system sales and purchases. Even taking the Company's estimates at face value, the proposed tracker requires customers to bear 100 percent of summer purchased power costs while crediting them with only 50 percent of off-system sales profits. Contrary to the Company's claims, the tracker's cost/profit distribution mechanism will likely result in a net cost to customers starting in 2004. Furthermore, the problematic split incentive mentioned above raises the possibility that off-system sales profits will be more likely to arise at times when the ratepayers benefit the least.

**Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION CONCERNING THE APPROVAL OF THE PROPOSED SUMMER RELIABILITY TRACKER?**

A. I recommend that the Commission reject the tracker as it is currently proposed. As I note elsewhere in my testimony, rate adjustment trackers such as the Summer Reliability Tracker often confer handsome benefits to shareholders while providing little or no tangible benefits to customers. I recommend that the Commission approve a modified version of the Summer Reliability Tracker that allows customers to retain 100 percent of off-system sales profits in all months of the year. Given the Company's failure to justify its need for such a significant profit incentive and given the magnitude of the Company's proposed rate increase, it stands to reason that customers should receive all of the off-system sales profits. Modifying the tracker in this manner would also greatly increase the probability that customers would indeed receive a net credit from the tracker, as Mr. Esamann has claimed.

Confidential Exhibit BEB-7 presents my analysis of the tracker's estimated net cost to customers under a scenario in which 100 percent of off-system sales profits are allocated to customers[redacted]. Averaged over the five-year period from 2003 to 2007, the rate impact of the tracker would be essentially revenue neutral, equaling an annual credit of [redacted].

**Q. WHAT PROCEDURES DEFINE HOW PSI AND OTHER CINERGY COMPANIES ENTER INTO TRANSACTIONS WITH ONE ANOTHER AND HOW ARE SUCH TRANSACTIONS ACCOUNTED FOR AMONG THE CINERGY COMPANIES?**

A. The Joint Generation Dispatch Agreement (JGDA) and Joint Transmission Agreement (JTA) were negotiated during 2001 in the context of FERC Docket

Nos. ER01-200-000 and ER01-200-001 and IURC Cause No. 41954. The IURC approved the settlement agreement containing the terms of the JGDA and JTA on September 11, 2001. The agreement sets out the manner in which Cinergy's generating and transmission assets are dispatched, and the manner in which system energy transfers, off-system purchase and sales, transmission system costs, and other transactions are allocated among the Cinergy companies.

Cinergy established an Administrative Operating Committee (AOC) to implement the JDGA. The minutes of that Committee are confidential. The topics that it deals with include specifics of how to implement the JDGA, including the treatment of various types of generating resources, the treatment of various types of loads, and the treatment of various types of transactions. The "Post Analysis Cost Exchange Program" (PACE) is used in implementing the JDGA. There are algorithms in PACE which determine the allocation and treatment of dispatch costs and transactions. These details can be complex, and they can have large impacts upon how costs are allocated among the Cinergy companies. There is a strong incentive for Cinergy to maximize the net revenues that are allocated to the deregulated business units and away from PSI, where they would be credited to regulated customers.

**Q. ACCORDING TO THE TERMS OF THE SETTLEMENT AGREEMENT, WHEN WILL THE NEXT COMMISSION PROCEEDING ASSESSING THE JGDA OCCUR?**

A. Section II.(F) of the settlement agreement provides for a 2004 process to "assess the feasibility, efficacy, and equity of continuing joint system dispatch and associated system energy transfers." Unless all the parties to the settlement agreement concur otherwise, PSI is required to file a petition with the Commission by March 15, 2004 to initiate an IURC assessment of the functioning of the JGDA.

**Q. WHAT DO YOU RECOMMEND THAT THE IURC DO WITH RESPECT TO THE JGDA, THE AOC, AND PACE?**

A. The interpretation and implementation of the JGDA and JTA are extremely complex, subject to manipulation, occurring in a context in which the decisionmakers have conflicting or problematic incentives, and important to the determination of the appropriate level of costs to be allocated to PSI for purposes of this rate case. The Company has provided some information on the AOC and PACE, but it was not in the Company's filing and it was obtained late in the discovery process. The Company's rate case filing was voluminous, but there was no witness who identified the issues in interpreting and implementing the JGDA, the implications of various transactions upon PSI, and the accounting procedures for those transactions. I believe that a more thorough review is required than has been possible in the rate case, and that such a review will take considerable time. I recommend that a sub-docket be initiated to address issues related to the JGDA, the AOC, and PACE. The issues would include:

(1) review of the implementation decisions made with respect to the JGDA;

(2) examination of the logic behind the PACE system to determinate whether it is logical, consistent, and fair;

(3) auditing of the methods and calculations of cost allocations associated with O&M, emissions, and transmission;

(4) consideration of the status of and adequacy of hourly market price data for use in the pricing of transactions;

(5) review of the transactions entered into and the basis for entering into particular transactions;

(6) examination of the timing of various decisions, e.g., when a contract is entered into, compared with when its treatment within PACE is determined (since time lags could create opportunities for risks to be shifted, as they were with the transfer of the merchant plants to regulated rates);

(7) assessment of the role of individuals on the AOC to determine whether and to what extent PSI's interests as a regulated utility and entity separate from Cinergy are being effectively are being effectively represented; and

(8) consideration of reserve margin requirements in the context of the implementation of the JGDA and PACE, to make sure that PSI's reserve requirement is determined on the basis of its customers' needs.

In effect, PSI should not be permitted to increase its rates based on the decisions of the AOC and the allocations of PACE until the Commission can verify that PSI manages its operations and transactions (including off-system power purchase sales activity) in the interests of its customers. The IURC should fully understand the processes, and the documentation and explanation should be sufficient to provide some confidence that PSI customers are not subsidizing the other Cinergy legal entities, or bearing risks that are not appropriately placed on the regulated entity.

**Q. HOW WOULD THIS SUB-DOCKET RELATE TO THE 2004 PROCESS?**

A. The sub-docket would provide a great deal of information and education with regard to the workings of the JGDA, the AOC, and PACE. It would focus on setting appropriate rates for PSI. The 2004 process would focus on whether to continue, amend, or terminate the JGDA. So the sub-docket would provide a great deal of useful background on how the JGDA has been implemented, which would help to inform the 2004 process.

## IV. NOX EMISSION ALLOWANCE TRACKER

**Q. WHAT ENVIRONMENTAL COMPLIANCE COSTS DOES PSI FACE?**

A. Because of its high level of reliance on coal-fired generation, PSI faces significant environmental compliance costs. The Company has spent approximately $540 million for equipment and $53.6 million for SO2 emission allowances in order to meet 1990 Clean Air Act Amendment regulations.[11] According to its own estimates, the Company faces $600 million or more in costs for additional pollution control measures.[12]

**Q. WHAT MUST PSI DO TO COMPLY WITH THE NOx SIP CALL?**

A. To comply with the SIP call, PSI needs to reduce its NOx emissions by 63%, or about 21,000 tons per year. The Company's NOx Compliance Plan includes installation of selective catalytic reduction and selective non-catalytic reduction

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[11] William F. Tyndall prefiled Case-in-Chief testimony, page 3.

[12] Douglas F. Esamann prefiled Case-in-Chief testimony, page 34.

controls, low NOx burners, and boiler optimization equipment at multiple generating units.[13]

**Q. WHICH OF THE COMPANY'S ENVIRONMENTAL COMPLIANCE COSTS ARE CURRENTLY RECOVERABLE THROUGH RATES?**

A. The Company has received approval for deferred ratemaking treatment for its NOx Construction Work in Progress (CWIP) projects, allowing the Company to recover the costs of its NOx Compliance Plan. Rider No. 63 also allows the Company to recover its costs associated with the acquisition of $SO_2$ emission allowances. In a separate SB 29 proceeding, the Company is requesting approval for an additional tracker which would allow it to concurrently recover depreciation and operation and maintenance expenses of its CWIP rather than defer the costs for future recovery.

**Q. WHAT ARE THE ESTIMATED RATE IMPACTS OF THE NOx CWIP AND SB 29 TRACKERS?**

A. Stephen Farmer testified under cross-examination that the revenues from NOx CWIP would increase base rates by approximately 3 percent, or about $33 million ($27.8 million of annualized CWIP revenue from Line 2, Column G of Petitioner's Exhibit C-5 plus $4.8 million of revenues from Rider No. 62 from Petitioner's Exhibit X-8). These costs are reflected in the test year period. Beyond the test year, Mr. Farmer approximated that the CWIP tracker would generate an additional $18 million in annual revenues on top of the 3 percent rate increase.[14] Adding this to the $33 million that is being included in base rates yields a total rate increase of about $51 million, or a 4 percent increase over current rates.

On an annualized basis, the rate impact of the SB 29 tracker is estimated to be between $12 and $13 million.[15] This would bring the cost to customers of PSI's NOx compliance plan to well over $60 million each year.

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13 Esamann prefiled Case-in-Chief testimony page 34.

14 Stephen M. Farmer's cross examination by Michael Mullett, page 45, line 15.

15 Stephen M. Farmer's cross-examination by Michael Mullett, page L-48, line 11.

**Q. WHAT PROJECTIONS HAS THE COMPANY PROVIDED WITH REGARD TO THE RATE IMPACT OF THE NOx EMISSION ALLOWANCE TRACKER?**

A. To my knowledge, the Company has not provided any projections predicting the rate impacts of the NOx Emission Allowance Tracker.

**Q. HOW MANY NOx EMISSION ALLOWANCES WILL THE ENVIRONMENTAL PROTECTION AGENCY (EPA) ALLOCATE TO PSI IN FUTURE YEARS?**

A. The Company estimates that, beginning in 2004, the EPA will allocate approximately [redacted] of NOx emission allowances to PSI each year.[16]

**Q. HOW DOES THE EPA'S ALLOCATION OF EMISSION ALLOWANCES COMPARE TO THE COMPANY'S PROJECTIONS OF FUTURE NOx EMISSIONS?**

A. According to its confidential estimates, PSI expects to emit more than [redacted] tons of NOx each year through 2007. The Company's projected emissions exceed its EPA EA allocation by an average of [redacted] tons per year between 2004 and 2007.[17] However, because of the Early Reduction Credits that PSI has earned and expects to earn through 2003, the Company does not anticipate the need to obtain additional NOx EAs or install additional NOx reduction equipment until approximately 2007 (see page 11 of John J. Roebel's pre-filed Case-in-Chief testimony).

**Q. UNDER WHAT CIRCUMSTANCES MIGHT THE COMPANY BE REQUIRED TO PURCHASE NOx EMISSION ALLOWANCES PRIOR TO 2007?**

A. If the Company's planned NOx reduction projects are delayed or experience operational problems, the Company's NOx emissions may exhaust its balance of EAs. Also, if the Company's electricity generation exceeds anticipated levels, NOx emissions may also increase and potentially require the Company to obtain EAs prior to 2007. In the previous section of my testimony I noted that the

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[16] Confidential Data Response OUCC/PSI-9-234-A.

[17] Ibid.

Company's load forecast may be unreasonably low. This increases the probability that PSI will need to acquire more EAs than it has projected.

Furthermore, the NOx SIP Call's flow control mechanism could restrict the Company's ability to use its banked EAs, and increase the likelihood that the Company will need to purchase additional EAs.[18]

**Q. WHAT UNCERTAINTIES EXIST CONCERNING THE MARKET FOR NOx EMISSION ALLOWANCES?**

A. It is extremely difficult to predict the future cost of NOx emission allowances. Like wholesale electricity markets, the market for EAs is subject to considerable volatility and price risk. Unexpected plant outages and high summer temperatures can cause sudden and dramatic increases in NOx EA prices. Likewise, "overinvestment" in NOx reduction measures by affected utilities can cause significant reductions in NOx EA prices. Publicly available data from the Cantor Environmental Brokerage Market Price Index indicates that NOx Early Reduction Credits were recently trading for approximately $5,500 per ton per year in Indiana.[19]

**Q. HOW DOES THE PROPOSED NOx EA TRACKER MITIGATE THE RISKS OF ENVIRONMENTAL COMPLIANCE?**

A. The Company's proposed NOx EA tracker assigns the majority (80 percent) of NOx EA acquisition costs related to serving native load to retail rates. Although the Company does not currently forecast the need to acquire additional EAs before 2007, changes in load, plant operations and other unforeseen circumstances could change the Company's NOx EA position. Beyond 2007, the Company's NOx EA situation is highly unknown. By allocating the principal share of NOx EA acquisition costs to retail customers, the proposed tracker serves to further reduce the environmental compliance risks that PSI faces. Adding the NOx EA tracker to its existing NOx program CWIP and SO2 EA trackers puts the Company in a position of very little risk exposure to the costs of complying with current environmental regulations.

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18 See William F. Tyndall's cross-examination hearing transcript, page I-53.

19 Data as of June 2, 2003. Available at http://www.emissionstrading.com/index_mpi.htm, accessed 6/30/03.

**Q. ARE THERE ANY SIGNIFICANT DIFFERENCES BETWEEN THE NOx AND SO2 EA TRACKERS?**

A. Yes. Whereas the NOx EA tracker allocates 80 percent of net gains or losses from NOx transactions related to serving its native load obligations to customers, the SO2 EA tracker allocates 100 percent of such gains or losses to customers. I find this difference questionable because the Company appears to be supporting two otherwise entirely similar tracking mechanisms that have different cost allocation schemes. It would seem more appropriate for both trackers to allocate the same percentage of net gains and losses to customers. The disparate allocation schemes grant the Company the ability to profit where such opportunity exists (in the case where the Company has opportunity to sell some of its banked NOx EAs), while requiring customers to bear fully the costs of environmental compliance where profitable opportunities do not exist (in the case of the Company's continuing to be a net buyer of SO2 EAs).

Furthermore, the opportunity for gains from NOx EA sales has been created by the Company's pre-approved NOx compliance measures. The Company is already allowed to earn a return on these expenditures via the NOx CWIP tracker. Permitting the Company to profit from NOx EA sales when it already earns a return on the NOx compliance expenditures that create the sales opportunity would provide an inappropriate incentive for the Company and would prevent customers from realizing all of the potential economic benefits created by the NOx pollution controls which customers are fully funding through higher rates.

**Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION CONCERNING THE COMPANY'S PROPOSED NOx EA TRACKER?**

A. I recommend that PSI's NOx EA tracker be amended to allocate 100 percent of net gains and losses from NOx EA transactions to customers. The Company's proposal to retain 20 percent of potential gains from its NOx EA transactions constitutes an inappropriate profit incentive and does not appear to be in the best interest of its ratepaying customers. Allocating 100 percent of net gains and losses from NOx EA transactions to customers would also be consistent with the Company's existing SO2 EA tracker.

**Q. IN YOUR VIEW, DO THE COMPANY'S PROPOSED TRACKERS PROVIDE EQUAL BENEFIT TO ITS RETAIL CUSTOMERS AND SHAREHOLDERS?**

A. In my opinion, the Company's proposed trackers assign the majority of risks to its retail customers. The proposed Summer Reliability Tracker requires customers to bear 100 percent of summer purchased power costs, which are one of the Company's most significant risks. The proposed NOx EA Tracker likewise assigns 80 percent of EA acquisition costs to retail rates. The cumulative effect of these trackers is to shield PSI's shareholders from a large portion of the Company's most significant risks – at the expense of retail customers.

**Q. MR. ESAMANN'S TESTIMONY (PAGE 5, LINES 1-2) STATES THAT PSI'S "TRACKER PROPOSALS…ALIGN CUSTOMER AND SHAREHOLDER INTERESTS IN A BALANCED MANNER." IN YOUR VIEW, IS THIS AN ACCURATE STATEMENT?**

A. No. I believe that the proposed Summer Reliability and NOx Emission Allowance trackers require PSI customers to bear a disproportionate amount of the Company's exposure to risk. The trackers serve to further protect shareholder earnings and also include inappropriate profit incentives. Because the proposed trackers require customers to bear the significant and volatile costs of the Company's reliability purchases and environmental compliance, it is fair to expect that these same customers be entitled to the full benefits of off-system sales and NOx EA sales, where such opportunities exist. I encourage the Commission to consider the asymmetrical risk distribution of the Company's trackers when determining their appropriateness. I further encourage the Commission to consider the risk reduction and earnings protection afforded to shareholders by all of the Company's existing and proposed trackers when determining the appropriateness of the Company's requested ROE.

## V. <u>MERCHANT PLANT ACQUISITIONS</u>

**Q. WHEN WERE THE HENRY COUNTY AND MADISON GENERATING PLANTS CONSTRUCTED?**

A. The application for the Henry County construction permit was received in December of 1998. Construction was suspended by the IURC in March, 2000, and resumed in April, 2001. The plant began operating in the summer of 2001. The construction of the Madison/Butler County plant was announced in July of 1999, and the plant began commercial operation in May and June of 2000.

**Q. WHEN DID CINERGY SEEK TO TRANSFER THE OWNERSHIP OF THESE PLANTS TO PSI?**

A. In December of 2001, Cinergy proposed to transfer the plants to PSI in Cause No. 42145.

**Q. WHAT WERE THE MARKET PRICE PROJECTIONS AT THE TIME THAT CINERGY INVESTED IN THE PLANTS?**

A. In 1998 and 1999, the wholesale electricity market in the Midwest experienced unprecedented price spikes. The uncertain nature of the incipient market pushed forward price projections upward through the first half of 2001. For example, in the first four months of 2001, on-peak electricity for the Calendar 2002 period was routinely being traded for more than $50 per MWh, and throughout 2000 the market for Summer 2002 on-peak power rarely dropped below $90 per MWh.

**Q. WHAT WERE THE ACTUAL MARKET PRICES DURING 2002?**

A. According to day-ahead trading reported by Energy Argus, spot market, on-peak electricity in 2002 averaged well under $30 per MWh, and on-peak summer electricity averaged less than $35 per MWh. In other words, market price expectations in 2000 and 2001 exceeded actual prices by up to 150 percent. Exhibit BEB-8 presents a graph of actual 2002 (as indicated by day-ahead forward trades) prices compared against forward trades from 2000 and 2001.

**Q. WHEN DID MARKET PRICE EXPECTATIONS BEGIN TO FALL MORE IN LINE WITH ACTUAL PRICES?**

A. Beginning in the spring of 2001, 2002 forwards experienced a significant price decline. Graphs of 2002 summer and calendar forwards are presented in Exhibits BEB-9 and BEB-10. In April 2001, 2002 calendar forwards were routinely being traded for more than $50 per MWh. By late June, prices rarely exceeded $40 per MWh, and by October, they were trading at prices close to $30 per MWh. Summer forward prices experienced a similar decline – from about $90 per MWh in April to about $50 per MWh by late September.

**Q. WHAT WAS THE CONDITION OF THE WHOLESALE MARKET WHEN CINERGY/PSI FILED ITS PETITION IN DECEMBER 2001?**

A. In December 2001, 2002 forward electricity prices dropped to their lowest levels since these products began trading in 2000. Calendar forwards were trading for little more than $30 per MWh and summer forwards had dropped below $50 per MWh.

**Q. HOW DID THE CHANGED MARKET CONDITIONS AFFECT THE PROFITABILITY OF THE MERCHANT PLANTS?**

A. The value of new peaking units such as the Henry County and Madison plants is heavily dependent on wholesale market prices, particularly prices prevailing at times when additional generation is needed to meet peak system demand. Unregulated electric generating companies are likely to invest in peaking combustion turbine plants if they believe that such plants will recoup their investment through sufficiently high wholesale electricity prices. In 2001, the wholesale electricity market in the Midwest shifted from a period of price spikes and extreme volatility to one characterized by much reduced prices and volatility. These shifting market conditions would make it increasingly difficult for merchant peaking units such as the Henry County and Madison plants to be profitable to Cinergy's unregulated business.

**Q. DID CINERGY ACKNOWLEDGE THAT THE PLANTS WERE UNPROFITABLE AT THE TIME THAT PSI REQUESTED APPROVAL FOR THEIR PURCHASE?**

A. Yes. Cinergy acknowledged that the plants were not profitable in the initial years of their operation, but claimed to believe that the plants would still recover their costs in the long run.[20]

**Q. DOES ANY EVIDENCE EXIST TO SUGGEST HOW CINERGY VIEWED THE MERCHANT PLANTS AS FINANCIAL INVESTMENTS AT THE TIME OF THE PROPOSED TRANSFER TO PSI?**

A. Yes. Presentations given at several of Cinergy's Board meetings in 2001 allude to the importance of Cinergy's ability to recover its stranded merchant power plant costs. Confidential Exhibit BEB-11 presents a slide from a presentation of 2001 Cinergy financial results by R. Foster Duncan at a board meeting in January 2002. [redacted]

**Q. HOW DID THE APPROVAL OF THE MERCHANT PLANT TRANSFER AFFECT CINERGY'S ANTICIPATED STOCK PERFORMANCE?**

A. Information presented at the January 2002 Cinergy board meeting suggests that the merchant plant transfer had a significant impact on Cinergy's expected earnings per share. Confidential Exhibit BEB-13 presents a slide from Mr. Duncan's presentation showing the estimated impact of the merchant plant transfer at cost-based rates on Cinergy's 2002 Energy Merchant EPS plan. [redacted]

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20 See, for instance, Section II(B) of Petitioner's Reply Brief in Cause No. 42145, submitted November 28, 2002.

**Q. HAVE ANY CONCERNS BEEN RAISED WITH RESPECT TO THE PRICE THAT PSI PAID FOR THE MERCHANT PLANTS?**

A. Yes. The price that PSI paid Cinergy for the Madison and Henry County plants was one of the most contentious issues in the merchant plant transfer proceeding, Cause No. 42145. Several intervenors, including the OUCC, PSI Industrial Group (PSI-IG), and the Midwest Independent Power Suppliers (MWIPS), argued that the proposed sale price was unreasonably high. After Cinergy and PSI agreed to a slightly lower price in their settlement agreement with the OUCC, PSI-IG and MWIPS continued to argue that the plants were significantly overpriced.

The intervenors raised concerns over PSI's failure to obtain an independent assessment of the market value of the facilities and the relatively high cost per kilowatt of the plants in comparison to other merchant and utility plant sales and construction in the region. In particular, both PSI-IG and the OUCC compared the cost of Cinergy's merchant plants.to the cost of a combustion turbine constructed by Indianapolis Power & Light (IPL). Per the terms of the settlement agreement in Cause No. 42145, PSI paid $528/kW for the merchant plants,[21] while IPL received approval in Cause No. 42033 to construct its combustion turbine plant at a cost of $341/kW.[22]

The evidence presented by the intervenors and the contentiousness surrounding the value of the Madison and Henry County plants further support the implication that the plants' value had significantly diminished since their inception, and that their transfer to PSI at book value constituted a boon to Cinergy shareholders at the expense of regulated ratepayers.

**Q. DID PSI CHALLENGE THE ARGUMENTS CONCERNING THE DIMINISHED MARKET VALUE OF THE MERCHANT PLANTS?**

A. Yes. PSI vigorously challenged the assertion that the merchant plants were worth less than their book value, and provided several counterarguments that attempted to justify the reasonableness of their purchased price. However, the confidential

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21 PSI purchased the plants for $376 million (Mr. Esamann's prefiled testimony, page 37). Dividing this by their combined capacity of 712 MW yields $528/kW.

22 Redacted Prefiled Testimony of OUCC witness Robert M. Endris in Cause No. 42145, page 30, line 17.

information in Exhibits BEB-11 and BEB-13 concerning the plants' impact on EMBU earnings per share provides indisputable evidence that their transfer to cost-based rates generated significant earnings protection for Cinergy shareholders.

**Q. IN LIGHT OF THE SETTLEMENT AGREEMENT APPROVED BY THE COMMISSION IN CAUSE NO. 42145, WHY ARE THESE ISSUES PERTINENT TO THE CURRENT PROCEEDING?**

A. I acknowledge that the profitability and value of the plants and Cinergy's motives for seeking their transfer were addressed at length in Cause No. 42145 and ultimately settled in an agreement that was approved by the Commission. By briefly revisiting these issues, I do not intend to cast doubt upon the terms of the settlement agreement. Rather, the purpose of my discussion of these issues is to examine how PSI's holding company benefits prospectively from reduced exposure to risk as a result of the merchant plant transfer and the implications of this reduced risk exposure on the Company's proposed rate of return on equity in this current rate case

The plants' lack of profitability in the initial years of their operation had a negative impact on Cinergy's earnings per share and posed similar risks for the future. Their transfer to a regulated affiliate operating under cost-based rates allows Cinergy to recover essentially all of the plants' capital costs and to earn a regulated rate of return on those investments. In effect, this represented a transfer of risk from Cinergy, who became protected from the risks of recovering the costs of its highly speculative merchant plant investment, to PSI's customers, who will now bear the economic risks of the plants priced at embedded cost.

**Q. WHAT ARE THE REGULATORY IMPLICATIONS OF MERCHANT PLANT TRANSACTIONS BETWEEN THE UNREGULATED AND REGULATED AFFILIATES OF THE SAME HOLDING COMPANY?**

A. Because of the potential for market abuse, such transactions have come under increasing scrutiny from regulatory agencies. For example, the Federal Energy Regulatory Commission (FERC) recently ordered an administrative review of long-term power purchase contracts between Southern Co.'s unregulated subsidiary and its regulated affiliates Georgia Power Co. and Savannah Electric and Power Co., over concerns regarding whether the agreements adversely affect wholesale competition.[23]

While it approved without hearing Cinergy's request to transfer its merchant plants to PSI, FERC also acknowledged the ramifications of such transactions on electricity market competitiveness and fairness, noting, "The ability of a franchised utility to assume its affiliated merchant's generation when market demand declines gives the affiliated merchant a safety net that merchant generators not affiliated with a franchised utility lack."[24]

Since Cinergy's merchant plant transfer, FERC has set a hearing for the proposed transfer of generating and interconnection facilities from Amergen Energy Generating Co. to its regulated affiliate, Ameren Union Electric. The Illinois Commerce Commission, which has pre-approval authority over the transfer, recommended to FERC that it reject the transaction.[25]

**Q. HOW DOES THE MERCHANT PLANT TRANSFER TO THE REGULATED COMPANY AFFECT THE RISK BORNE BY PSI RATEPAYERS AND ITS ONLY SHAREHOLDER, CINERGY?**

A. There are two important considerations relevant to risk allocation.

First, the fact that the IURC pre-approved this transfer on the terms that it did indicates that PSI is operating in a *very* favorable regulatory climate for shareholders. That is, the regulated utility business, PSI, is not only being protected from many risks attendant to its own business by its tracker mechanisms – it has also been used to transfer risk to PSI customers associated with the activities of Cinergy's unregulated subsidiaries that would have otherwise been borne by Cinergy's shareholders. From the perspective of current and prospective Cinergy shareholders, this risk transfer is quite valuable. From the perspective of PSI ratepayers, however, there is a problematic asymmetry with the situation,

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[23] Dow Jones Business News, "FERC Orders Review of Southern Power Deals," July 9, 2003.

[24] Foster Electric Report, "Concerned About the Effect on Competition, FERC Sets for Hearing the Proposed Transfer of Generation and Interconnection Assets of Ameren's Subsidiaries." Report No. 306, May 14, 2003.

[25] Ibid.

unless the risk transfer is reflected in the ROE allowed Cinergy on the plant investment, i.e. by lowering the ROE relative to what would otherwise be allowed. If there is no such adjustment to the allowed ROE for Cinergy's investment, then PSI's ratepayers will have been subjected to a "heads I win, tails you lose" proposition.

Second, there is the PSI business and regulatory risk reduction normally attendant to pre-approval of generating facilities. Pre-approval is intended to eliminate the risk of unnecessary plant, as well as plant that is excessively costly to construct or acquire. Similarly, it is intended to eliminate the risk of regulatory disallowance for unnecessary or excessively costly plant. The merchant plants, as well as the Noblesville Repowering Project, have been pre-approved by the Commission. This means, *a fortiori*, that the risks of their plant capacity being unnecessary or excessively costly, and the associated risks of partial or total regulatory disallowance, have been eliminated as far as these three plants are concerned. This risk reduction should also be reflected in a lower required ROE with respect to the investment in these three plants than would be the case in the absence of pre-approval.

## VI. MANAGING RISKS, RESOURCE DIVERSITY, AND AIR EMISSIONS

**Q. DOES CINERGY ACTIVELY MANAGE ITS RISKS?**

A. Yes. Cinergy appears to actively analyze and manage its risks, focusing on the risks to shareholders. The following is an excerpt from its 2002 annual report.

> We manage, on a portfolio basis, the market risks in our energy marketing and trading transactions subject to parameters established by our Risk Policy Committee. Our market and credit risks are monitored by the Global Risk Management function to ensure compliance with stated risk management policies and procedures. The Global Risk Management function operates independently from the business units and other corporate functions, which originate and actively manage the market risk exposures. Policies and procedures are periodically reviewed to ensure their responsiveness to changing market and business conditions. Credit risk mitigation practices include

> requiring parent company guarantees, various forms of collateral, and the use of mutual netting/closeout agreements.[26]

Cinergy's presentations to its Board of Directors also focus upon risks to shareholders and the role of favorable regulation in securing shareholder earnings. Confidential Exhibit BEB-14 presents a slide from the February 6, 2003 Cinergy Board Meeting presentation given by Cinergy's CEO of Regulated Businesses, Jim Turner. [redacted]. Confidential Exhibit BEB-15 is an excerpt from an internal memo from Jim Rogers to the Cinergy Board of Directors, dated October 1, 2002. [redacted]

**Q. DOES PSI ACTIVELY MANAGE RISKS TO REGULATED CUSTOMERS?**

A. No. PSI and Cinergy appear to be relatively passive in analyzing and managing risks to PSI customers. There is a notable contrast between the Company's focus on the projected effects of regulatory proposals on shareholder earnings, as referenced above, and its relative lack of inquiry and analysis concerning the rate impacts of its trackers on its customers in future years. The Company's heavy reliance on trackers effectively shifts PSI's risk exposure to its customers, yet the Company has demonstrated little concern in attempting to quantify these ratepayer risks beyond the test year period.

**Q. SHOULD PSI MANAGE THE RISKS TO ITS CUSTOMERS?**

A. Yes, of course PSI should analyze and manage the risks to which its customers are exposed. For example, PSI should monitor and analyze various uncertainties that bear upon its future costs of providing service, including fuel prices, power market prices, and environmental compliance costs – and take affirmative steps to mitigate those risks and their impact on customers. The Company is clear that

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26 Cinergy Corp. 2002 Annual Report, "The Faces of Leadership," page 58.

there is uncertainty in the components of those costs, but the trackers appear to give PSI sufficient confidence that fluctuations in those costs will not have a detrimental effect upon PSI's shareholder (Cinergy). The result appears to be a situation in which neither PSI nor Cinergy believes that the costs and risks covered under trackers need to be thoroughly analyzed and mitigated precisely because they are being tracked.

**Q. WHAT EFFECT DO THE TRACKERS HAVE UPON RISKS TO SHAREHOLDERS?**

A. Relative to traditional regulation, the trackers shift risk from shareholders to customers. Because the earnings are based upon the difference between two large numbers (total costs and total revenues), shareholders under traditional rate regulation (without trackers) are exposed to risks associated with volatility on the cost side (e.g., power costs could be higher than anticipated) and on the revenue side (e.g., sales could be lower than expected). With the trackers, earnings become relatively quite stable and predictable. Shareholders are protected from volatility in those components that are tracked. With trackers covering costs that are volatile or rising (e.g., fuel, purchased power, environmental compliance) PSI's shareholder is exposed to very little risk (e.g., stable items such as depreciation, or unlikely findings of imprudence with associated disallowances for costs such as transmission and distribution investment and wage and salary or tax expense). The result of the trackers is to reduce volatility and risk in shareholder returns, putting that volatility into the prices that customers pay.

**Q. ARE THERE ACTIONS THAT PSI COULD TAKE TO REDUCE ITS EXPOSURE TO ENVIRONMENTAL RISKS?**

A. Yes. PSI could more actively address its environmental risks. PSI has made some effort to diversify it generation mix, to reduce emissions from its existing plants, and to implement demand-side management programs. These efforts, however, are quite limited and reflect an approach of doing the minimum required. PSI should serve its customers with low cost, reliable power in a way that also diversifies the resource mix, cleans up the existing fleet of plants, and expands energy efficiency programs.

**Q. YOU MENTIONED PSI RESOURCE MIX, AND THE NEED FOR FUEL DIVERSITY AND EMISSIONS REDUCTIONS. WHAT IS THE CURRENT SITUATION AND WHAT SHOULD PSI DO?**

A. According to EPA data ("eGRID") Cinergy's generation mix in the year 2000 was 98% coal. Cinergy's emissions of $CO_2$, $SO_2$, and $NO_x$ in 2000 were 67 million tons, 560 thousand tons, and 154 thousand tons, respectively. It was the nation's fourth largest emitter of $CO_2$ and $SO_2$ (after AEP, Southern, and Xcel Energy) and the third largest emitter of $NO_x$ (after AEP and Southern). According to Cinergy's "Environmental, Health and Safety Progress Report 2002" its emissions of $SO_2$ and $NO_x$ decreased between 2000 and 2002, while its $CO_2$ emissions stayed level, and its particulate emissions increased.

PSI's share, relative to the Cinergy totals is about 59% of the 2000 amount of generation. PSI's share of $CO_2$ emissions is also 59% of the total. For $SO_2$, PSI's share is higher (66% of total) and for $NO_x$ PSI's share is lower (53% of total). These shares are based upon EPA's eGRID data.

Cinergy has made investments in selective catalytic reduction (SCR) to control $NO_x$ emissions (the "Environmental, Health and Safety Progress Report 2002," p.4, reports four out of nine planned SCR units to have been completed).

In addition, the repowering of Noblesville has increased the station's capacity and switched its fuel from coal to gas. This represents progress toward improving the efficiency of Cinergy's generating mix, and diversity of its fuel supply, but Noblesville represents just 300 MW of capacity in a system of about 12,000 MW.

Cinergy and PSI are making some progress in reducing some important types of air emissions and diversifying the fuel mix to include a small slice of gas in addition to coal. However, this progress is very gradual, and appears to be the minimum required to comply with regulations. Carbon dioxide emissions, fine particulates, and toxics such as mercury will be important for Cinergy to address. Demand side programs and renewable generating resources will be essential components of a low cost and prudent strategy to manage these emissions and associated risks.

**Q. YOU MENTIONED ENERGY EFFICIENCY PROGRAMS. WHAT IS THE CURRENT SITUATION WITH REGARD TO PSI'S DSM PROGRAMS AND WHAT SHOULD PSI DO?**

A. PSI's investments in demand-side management (DSM) programs during the 1990s are plotted in Exhibit BEB-16. PSI's annual spending on DSM peaked in 1994 at $40 million per year of spending (with incremental energy savings of 172 GWh/year), declining to less than $2 million per year in the late 1990s (with incremental energy savings of less than 20 GWh/year). DSM programs and investments in renewable generating technologies provide benefits in reducing exposure to environmental risks. For a Company that is heavily dependent upon coal-fired generating facilities in a policy context of increasingly comprehensive and stringent air emissions regulations (including likely future restrictions on emissions of carbon dioxide in order to address global climate change), the role of efficiency and renewables can be particularly important.

**Q. HOW DID THE COMPANY EXPLAIN ITS MARKED DECLINE IN DSM INVESTMENTS IN THE LATE 1990s?**

A. Richard G. Stevie, under cross-examination in this case, explained the Company's decreased DSM investments as follows:

> They [DSM investments] were greater in the early '90s up until about 1996 or 1997, somewhere in there, when I think it became – it became evident that for the larger customers, they felt that it would – it was very easy for them to go out into the marketplace and obtain energy efficiency services on their own rather than paying for it through the utility and having the utility provide those services.[27]

The data reported by the Company to EIA show PSI spending on DSM peaking in 1994 at $40 million (see Exhibit BEB-16). The notion that large customers can obtain energy efficiency on their own is a poor reason to discontinue cost-effective programs to encourage efficient use of electricity. Other companies have found ways to provide cost-effective programs to large and small customers.

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[27] Richard G. Stevie cross-examination by Michael Mullett, page J-127, line 11.

**Q. DO PSI'S DSM COST EFFECTIVENESS SCREENING MECHANISMS SUFFICIENTLY ACCOUNT FOR THE AVOIDED ENVIRONMENTAL COMPIANCE COSTS THAT RESULT FROM INCREASED ENERGY EFFICIENCY?**

A. I am concerned that the Company's DSM cost effectiveness screening mechanisms do not sufficiently account for the avoided environmental compliance costs of energy efficiency programs. The following is an excerpt from Michael Mullet's cross examination of Mr. Stevie:

> Q. Could you explain how environmental risk is factored into the various tests that are employed to evaluate the cost effectiveness of the demand side management program?
>
> A. The programs that we have pass the cost effectiveness test without including any potential environmental benefits. What you see is once these programs are passed on to the integrated resource planning process, that any reductions in environmental costs would be captured within the analysis of the integrated resource plan. We don't specifically identify a particular environmental savings for these programs here. They already pass the cost effectiveness test.[28]

This suggests that PSI's DSM cost screening mechanism does not address the environmental risks posed by future regulatory regulatory compliance costs (e.g. $CO_2$ and mercury emissions). Given the Company's heavy reliance on coal generation and its pronounced vulnerability to new environmental regulations, aggressively pursuing DSM would seem a prudent environmental risk management policy that the Company can ill afford to overlook.

**Q. HAVE YOU ANALYZED THE POTENTIAL FOR PSI TO INCREASE ITS INVESTMENT IN EFFICIENCY AND RENEWABLES?**

A. I have not conducted an analysis specific to PSI. I have, however, done an analysis of the broader region – the ten states ranging from the Dakotas in the west to Ohio in the east. The results specific to Indiana are summarized on a two-page document provided here as Exhibit BEB-17. The executive summary of the regional analysis is provided as Exhibit BEB-18.

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[28] Richard G. Stevie cross examination by Michael Mullett, page J-119, line 17.

For this region, we found that a "clean energy development plan" compared with the "business as usual" scenario could reduce electric system carbon dioxide emissions by 51 percent in 2020. This would be a 36 percent reduction relative to actual electric sector carbon dioxide emissions in the year 2000.

The cost of the clean energy plan, which emphasized efficiency programs and renewable electricity generating resources, was estimated to be only 3.4 percent higher than total electricity costs in the business as usual case. The details of this analysis are available in the report "Repowering the Midwest: The Clean Energy Development Plan for the Heartland," available online at http://www.repowermidwest.org.

For PSI to implement a utility system portion of the energy efficiency programs included in the regional clean energy plan would serve to reduce its exposure to the environmental compliance risks of dependence on coal, while actually reducing total costs to its customers. An aggressive and cost-effective set of demand-side management programs can cut demand growth to less than half of what it would otherwise be.

For PSI to implement its share of the renewable generating capacity would also serve to reduce its exposure to environmental risks, at costs that could reasonably be borne by customers. Based upon this regional study, and the state-specific results from the study, it is reasonable to conclude that PSI could and should aggressively develop and implement cleaner generating resources and energy efficiency programs, in order to better serve its customers.

In contrast with the clean energy plan, Cinergy's approach is minimal. The Company chooses to do what is required, but does not go beyond that minimum to anticipate future regulations, to proactively reduce its environmental footprint, or to significantly diversify it predominantly coal resource mix.

**Q. IN YOUR OPINION, DOES CINERGY'S CURRENT APPROACH REPRESENT PRUDENT MANAGEMENT OF PSI'S ENVIRONMENTAL RISK?**

A. No, it does not. There is a definite difference between managing environmental risk and managing environmental compliance risk. Cinergy's approach equates the two approaches. For Cinergy, global warming and climate change are not risks worth managing for PSI because they have yet to be reflected in environmental regulations or court orders legally requiring particular emissions to be reduced to particular levels.

But, the international scientific community has concluded that global warming and climate change are real phenomena with real costs and consequences to people and the planet—and the emissions from coal-fired power plants unquestionably contribute significantly to those phenomena. Moreover, Cinergy is making decisions today regarding PSI investments in technology, plant and equipment which will continue to have consequences 20, 40 even 60 years or more in the future.

Given those two factors—the reality of climate change and its consequences and the certainty that Cinergy's decisions today regarding PSI investments can and will affect that reality in the future—Cinergy must have a strategy for managing PSI's greenhouse emissions that is reasonably calculated to be least cost in the long run to be prudently managing PSI's environmental risk. A least cost plan to comply with only the most current environmental regulations is simply not enough in this day and age.

Most worrisome, Cinergy top management knows this, but has heretofore done nothing about it beyond running alternately hot and cold on the necessity for enactment of "four pollutant" legislation at the national level. But, with or without national legislation, Cinergy top management has an obligation to PSI customers to develop and propose to this Commission a strategy for managing PSI's greenhouse emissions that is reasonably calculated to be least cost in the long run. Until they have done that, in my opinion, Cinergy is not prudently managing PSI's environmental risk.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.