M E M O R A N D U M

JULY 17, 2002

TO: DIVISION OF THE COMMISSION CLERK AND ADMINISTRATIVE SERVICES

FROM: OFFICE OF THE GENERAL COUNSEL (KEATING) WCK

RE: DOCKET NO. 011605-EI - REVIEW OF INVESTOR-OWNED ELECTRIC UTILITIES' RISK MANAGEMENT POLICIES AND PROCEDURES.

Attached is the original and seven copies of Direct Testimony of Todd F. Bohrmann to be filed in the above-referenced docket.

WCK/jb

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of investor-owned electric utilities' risk management policies and procedures.	DOCKET NO. 011605-EI DATED: JULY 17, 2002

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of Direct Testimony of Todd F. Bohrmann has been furnished by U. S. Mail this 17th day of July, 2002, to the following:

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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DOCKET NO. 011605-EI - Review of Investor-Owned Electric Utilities' Risk Management Policies and Procedures

WITNESS: **Direct Testimony of Todd F. Bohrmann,** Appearing On Behalf Of Staff

DATE FILED: July 17, 2002

DIRECT TESTIMONY OF TODD F. BOHRMANN

Q Would you please state your name and business address.

A My name is Todd F. Bohrmann; 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32399-0850.

Q By whom are you employed and in what capacity?

A I am employed by the Florida Public Service Commission as an Economic Analyst for the Bureau of Electric Reliability, Division of Economic Regulation.

Q Please give a brief description of your educational background and professional experience.

A I was graduated from the University of Central Florida in 1989 with a Bachelor of Arts degree in Economics. I earned a Master of Business Administration degree from the University of Central Florida in 1992.

I was employed by the Florida Department of Environmental Protection as an economist from November 1992 through May 1994. I began employment with the Florida Public Service Commission as a Regulatory Analyst in May 1994. I was promoted to my current position in April 2001.

Q What are your present responsibilities with the Commission?

A I provide technical support and advice to the Commission for docketed and undocketed matters concerning electric utilities in Florida. Among my responsibilities, I am the lead technical analyst for the Commission's fuel and purchased power cost recovery clause.

Q Have you previously testified before the Commission?

A Yes. On April 29-30, 1997, I presented a framework for establishing territorial boundaries in a dispute between Gulf Power Company and Gulf Coast

Electric Cooperative in Docket No. 930885-EU.

Q What is the purpose of your testimony?

A My testimony addresses Issues 2-4 as identified in Order No. PSC-02-0192-PCO-EI, in Docket No. 011605-EI, issued February 12, 2002. In addition, my testimony addresses Issues 1A and 1B as identified by Order No. PSC-02-0821-PCO-EI, in the same docket, issued June 14, 2002. Finally, my testimony also addresses Issues 7A and 7B as identified in Order No. PSC-02-0854-PCO-EI, in the same docket, issued June 21, 2002.

The purpose of my testimony is two-fold: 1) provide essential background information about managing risks associated with fuel procurement; and 2) provide a course of action that the Commission should follow to monitor the cost recovery of each investor-owned electric utility's (utility) risk management activities.

Q Have you attached any exhibits to your direct testimony?

A Yes, I have attached twelve (12) exhibits to my direct testimony. TFB-1 is titled "Investor-Owned Electric Utilities' Natural Gas-Fired Generation: 1991, 2001, and 2011." TFB-2 is titled "History of Risk Management". TFB-3 is titled "Establishment of and Modifications to Fuel and Purchased Power Cost Recovery Clause." TFB-4 is titled "Components of a Utility's Risk Management Plan." TFB-5 is titled "Total Fuel Cost Statistical Measures for Florida Power & Light Company, Florida Power Corporation, Gulf Power Company, and Tampa Electric Company: July 1996 through June 2001." TFB-6 is titled "Comparison of High Bill Complaints Filed with the Commission by Florida Power & Light Company's, Florida Power Corporation's, and Tampa Electric Company's Ratepayers." TFB-7 is titled "Example of A Utility Engaging in Futures

Contracts to Hedge Its Natural Gas Costs." TFB-8 is titled "Example of A Utility Engaging in Options Contracts to Hedge Its Natural Gas Costs." TFB-9 is titled "Excerpts from Order No. 14546, Docket No. 850001-EI-B, Issued July 8, 1985, Pages 4-5." TFB-10 is titled "Definition and Hypothetical Example of Each Type of Risk That A Utility May Experience with its Fuel Procurement Transactions." TFB-11 is titled "Types of Hedging Techniques." TFB-12 is titled "Glossary of Terms."

I have offered the following exhibits for informational purposes only. TFB-2 provides information to place this docket in its appropriate historical context. TFB-3 provides information about the establishment of and modifications to the fuel and purchases power cost recovery clause. TFB-5 provides information which links each utility's fuel cost volatility to the number of mid-course corrections the Commission has granted each utility from July 1996 through June 2001. TFB-7 provides information about the mechanics of hedging a utility's fuel procurement through futures contracts. TFB-8 provides information about the mechanics of hedging a utility's fuel procurement through options contracts. TFB-10 provides a definition and hypothetical example of each type of risk that a utility may experience with its fuel procurement. TFB-11 provides information about each type of hedging technique that a utility may implement to minimize the risks associated with its fuel procurement. TFB-12 provides a definition of unique terms that appear in my testimony.

Q To what extent did/will Florida Power Corporation (Florida Power), Florida Power & Light Company (FPL), Gulf Power Company (Gulf Power), and Tampa Electric Company (Tampa Electric) use natural gas to generate electricity in the past, present, and future?

A As TFB-1 illustrates, the amount of each utility's natural gas-fired generation has increased during the past ten years and is expected to increase substantially over the next ten years. In 1991, a utility might have used natural gas to provide peaking capacity, but utilities now have increasingly turned to natural gas-fired generation for base load and cycling capacity needs.

Q To what extent has each utility used *futures* and *options contracts* to reduce uncertainty over natural gas prices?

A During the past four years, FPL has engaged in a limited number of exchange-traded futures and options contracts to reduce natural gas price volatility. Florida Power, Gulf Power, and Tampa Electric have engaged in virtually no exchange-traded futures and options contracts. The four utilities do engage in numerous *forward and swap contracts* where the utility and the seller(s) can specify the contract's terms and conditions to meet their needs.

ISSUE 1A: What role should the Commission take concerning the manner in which each investor-owned electric utility manages risks associated with fuel procurement?

Q What is the Commission's role concerning the manner in which each utility manages the risks associated with its fuel procurement?

A The Commission's role - informed, neutral arbiter of a utility's ratepayers' and shareholders' interests - remains unchanged from the status quo. Through its ratemaking authority, the Commission authorizes each utility to recover its prudent fuel and purchased power costs (fuel costs) *dollar-for-*

dollar through the fuel and purchased power cost recovery clause (fuel clause). The fundamental question for this docket is whether a utility which does not minimize the risks associated with its fuel procurement is acting prudently.

Q Does the regulatory treatment that the Commission provides to each utility impact the level of risks that a utility's ratepayers and shareholders bear?

A Yes. The Commission establishes a levelized fuel and purchased power cost recovery factor (fuel factor) for each utility on a calendar year basis through a post-hearing order, commencing January of each year. Unless the Commission modifies a utility's fuel factor through a mid-course correction, the fuel factor remains fixed throughout the calendar year. Meanwhile, a utility incurs fuel costs that fluctuate instantaneously. Hence, a utility's ratepayers participate in a *floating-for-fixed* swap which does reduce fuel cost volatility from the <u>ratepayer's</u> perspective.

The utility, like any individual or firm, can *hedge* its cash flows to minimize the uncertainty associated with those cash flows. However, if a utility can collect, dollar-for-dollar, all prudent fuel costs from its ratepayers, the utility's shareholders are participating in a *perfect hedge*. From the <u>shareholders'</u> perspective, the utility does not need to expend additional time, money, or effort to hedge those cash flows further. Therefore, a utility which further hedges its fuel procurement does so for the benefit of its <u>ratepayers</u>, not its shareholders.

Q Can the utility's ratepayers minimize these risks independently?

A No. A few ratepayers, large industrial customers, may have the sufficient load, financial wherewithal, time, market knowledge, and willingness to minimize these risks independently. However, the overwhelming majority of ratepayers do not.

Q Pursuant to its role, should the Commission require each utility to file a risk management plan?

A Yes. In TFB-4, I have outlined the components of a comprehensive risk management plan (plan) that each utility should file with the Commission. The Commission should mandate that each utility submit its plan no later than 60 days after the final Commission order in this docket. Once the Commission staff determines that the utility has filed a *complete risk management plan*, Commission staff will evaluate each utility's plan within 60 days. The Commission can then either approve, reject, or modify the utility's plan. After the initial approval, the utility should seek approval from the Commission for each substantial modification. To protect the utility's competitive interests, each utility can petition the Commission for the appropriate confidential treatment of such sensitive information as permitted by law.

Q Why should each utility submit this information to the Commission?

A The Commission must make timely, informed decisions about the prudence of the billions of dollars that are recovered through the fuel clause from the utilities' ratepayers annually. Whereas previously the Commission may have sought information only about the utility's cost level, the Commission should now also seek information about the cost volatility that the utility manages as well.

The Commission needs information about how each utility manages these risks for three reasons. First, the Commission must know the risks *ex ante* that a utility incurs for its ratepayers in its fuel procurement. Second, once the Commission knows the type and amount of these risks, the Commission may set conditions for recovery to limit the utility's ratepayers' risks. Third, the Commission needs this information to make more timely, better informed decisions about the prudence of a utility's fuel procurement.

In March 2001, for example, the Commission was concerned about the prudence of FPL's and Florida Power's actions regarding its natural gas procurement transactions during a period of extremely high natural gas prices during December 2000 and January 2001. After 15 months and significant discovery between the two utilities and staff, the Commission recently stated through two proposed agency action orders that both FPL and Florida Power prudently incurred the incremental costs associated with the events of December 2000 and January 2001. If FPL and Florida Power had filed their respective plans prior to December 2000, the Commission could have compared each utility's actions with each utility's plan approximately one year earlier.

<u>ISSUE 1B:</u> Is each investor-owned electric utility taking reasonable steps to manage the price risk associated with its natural gas and residual oil transactions, as well as purchased power transactions based on natural gas prices, through the use of physical, operational, or financial hedging practices, or a combination of those practices?

Q What criterion should the Commission implement to determine whether each utility is taking reasonable steps to manage the price risk associated with its natural gas-fired and residual oil-fired generation resources?

A A utility should procure no less than the <u>minimum</u> amount of each fuel that the utility <u>must</u> dispatch on its system through one or more *fixed price mechanisms*.

Q Please explain.

A Under the constraints of non-economic limitations, each utility dispatches its system's resources in ascending order of each resource's marginal costs to meet the utility's load. As the relative price of a fuel rises, the resource's marginal cost increases and the utility may dispatch the resource less frequently. Possibly, a utility may not dispatch a resource ever once the relative price of a fuel is greater than a given level. However, depending upon the type and amount of the utility's resources, a utility may dispatch a certain amount of a specific resource regardless of the relative price of a fuel.

Q What impact would this event have on the utility's ratepayers?

A Assume a utility must dispatch a minimum 100 MW of natural gas-fired capacity at all times regardless of the relative price of natural gas. If the utility does not manage the price risk associated with its natural gas procurement, its ratepayers may someday pay two, three, or ten times the historical price for that natural gas. This scenario places a harsh economic burden on the utility's ratepayers.

Q How would a utility's hedging actions protect the utility's ratepayers from the unlimited exposure to natural gas price increases?

A Once again, assume a utility must dispatch a minimum 100 MW of natural gas-fired capacity at all times regardless of the relative price of natural gas. However, the utility has implemented fixed price mechanisms to cap its ratepayers' exposure to 150 percent of the historical price of natural gas. If the ten year average price for natural gas is $2.50 per million British thermal units (MMBtu), the utility would cap its ratepayers' exposure to natural gas prices at $3.75 per MMBtu for the 100 MW of must-run natural gas-fired capacity through one or more fixed price mechanisms.

Q Does this strategy impose any costs upon the utility's ratepayers?

A Yes. A utility which implements fixed price mechanisms loses the opportunity to take advantage of any fuel price decreases in the spot market. In some time periods, a utility may purchase its fuel less expensively with a different strategy. During these periods, a utility's ratepayers can view any additional costs as insurance against substantially higher fuel costs during other periods.

Q Are these "insurance" costs a prudent fuel cost for the utility?

A Yes. If the utility incurs these insurance costs pursuant to a Commission-approved plan, I believe these costs would be prudent. In general, insurance not only protects the insured against loss, but also provides the insured "peace of mind" that any future loss will be protected as well. For example, an individual does not consider his automobile insurance premiums an imprudent cost if he does not file a claim with his insurance company during a given year.

Q On a prospective basis, describe how the Commission would compare a utility's actions with the utility's plan?

A The Commission would expect a utility's fuel procurement activities to be consistent with the utility's plan. If an activity is reasonably consistent with the utility's plan, the utility would recover this cost through the fuel clause. Conversely, if an activity is not reasonably consistent with the utility's plan, the utility would not recover this cost through the fuel clause.

ISSUE 7A: What incentive(s), if any, should the Commission establish to encourage investor-owned electric utilities to optimally manage the risks to ratepayers associated with fuel and purchased power price volatility?

Q Before we discuss an explicit Commission incentive, does each utility have an implicit incentive to manage pro-actively the risks associated with fuel procurement?

A Yes. Each utility has an implicit incentive to enhance the goodwill that exists between itself and its ratepayers through stable rates. In TFB-6, the data show an increase in the number of "high bill" complaints that FPL's, Florida Power's, and Tampa Electric's ratepayers filed with the Commission after the Commission approved a series of requested rate increases. These data suggest the loss of goodwill that can develop between a utility and its ratepayers during a period of volatile rates. A utility can enhance its goodwill with ratepayers by finding a balance between minimizing fuel costs and minimizing fuel cost volatility.

Q Should the Commission approve an explicit incentive to encourage a utility to pro-actively manage the risks associated with its fuel procurement?

A No. For the reasons set forth below, the Commission should not approve an explicit incentive at this time.

Q Should a utility's ratepayers receive the benefits associated with the utility's risk management efforts?

A Yes. Under the Commission's current policy, a utility's ratepayers bear all costs and risks associated with the utility's prudent actions to procure fuel. Conversely, a utility's shareholders bear neither any cost nor risk associated with the utility's prudent actions to procure fuel. Therefore, a Commission incentive to share the benefits of a utility's risk management efforts would misdirect resources to shareholders, and away from ratepayers. This incentive would reward the utility's shareholders who have not borne, do not bear, and will not bear any costs or risks associated with the utility's prudent actions to procure fuel.

Q At some future time, should the Commission consider approving an explicit incentive to each utility to manage the risks associated with its fuel procurement?

A Yes. By their own admission, the utilities have little to no experience in executing financial hedging transactions. Each utility will expend sufficient resources to build the infrastructure needed to identify, evaluate, and execute financial hedging transactions that create value for its ratepayers. After the utility builds its infrastructure, the Commission will need several years of data to determine whether and to what extent each utility's efforts have created value for its ratepayers. Once the Commission evaluates these data, then the Commission can entertain such incentive mechanisms that create additional value that can be shared between the shareholders AND ratepayers. I do not believe that the public interest is served by an incentive that benefits utility shareholders before the utility demonstrates even the first dollar of value is accrued to its ratepayers.

Q Absent an explicit incentive, how can the Commission most effectively encourage each utility to pro-actively manage the risks associated with its fuel procurement?

A The Commission can encourage each utility to pro-actively manage the risks associated with the utility's fuel procurement. First, pursuant to Commission approval of the utility's plan, the Commission can authorize the utility to recover gains and losses from futures contracts, premiums received and paid for options contracts, net settlement proceeds from swap contracts, and transaction costs associated with these contracts through the fuel clause. Second, the Commission should exercise no bias for or against any hedging technique referenced in TFB-11 to manage the risks associated with the utility's fuel procurement. These actions will provide each utility with greater certainty about the regulatory treatment of its hedging transaction cash flows.

Q Can an explicit incentive to a utility to pro-actively manage these risks be counter-productive?

A Yes. An incentive mechanism that produces one or more of the following outcomes can become counterproductive and misallocate resources:

1. The incentive mechanism mandates the utility to take actions that the utility would not take in the absence of an incentive;
2. The incentive mechanism mandates the utility to take actions that the utility would take regardless of any incentive;
3. The incentive mechanism does not create any additional value, but merely re-allocates existing value;
4. The utility has direct control over the bases on which the utility's actions are compared; or

5. The bases on which the utility earns the incentive are outside the utility's control.

Q FPL, Florida Power, and Gulf Power have put forth their respective incentive mechanisms that they propose the Commission should approve to encourage each utility to pro-actively manage the risks associated with the utility's fuel procurement. Do you have any comments about each utility's proposals?

A Yes. I have some general comments that apply to the three proposals, and comments that are specific to each proposal. I will state my general comments first. If the Commission believes an incentive mechanism is warranted, the Commission should consider the following:

1. As an antecedent condition of receiving any incentive, the utility should first receive Commission approval of its plan in the format proposed in TFB-4;
2. Initially, the Commission should approve any incentive mechanism as part of a pilot program with a minimum two year term;
3. Any mechanism should provide an incentive to the utility to find a balance between minimizing fuel costs AND minimizing fuel cost volatility;
4. Any incentive mechanism should create additional value that the Commission can allocate between the shareholders and ratepayers;
5. Any incentive mechanism should not consider any transaction between the utility and an affiliated entity when

calculating the amount of the incentive;

6. The Commission should strictly define the events which qualify as a force majeure; and

7. The Commission should not allow the recovery of any incremental capital and O&M costs (e.g., personnel, computer hardware and software, allocated common costs) through the fuel clause. Such costs are "fuel procurement administrative functions" which the Commission has historically authorized the utilities to recover through its base rates as contemplated by Order No. 14546, in Docket No. 850001-EI-B, issued July 8, 1985. TFB-9 provides relevant portions of this Order.

Q What are the more favorable features of FPL's proposal?

A FPL's proposal has the following more favorable features:

1. FPL will establish a fixed price for a pre-determined percentage of its natural gas and residual oil requirements. Any difference between these fixed prices and FPL's actual costs will accrue to its shareholders; and

2. For an event to qualify as a force majeure event, FPL's proposal has a two-prong test. First, the event must be an unpredictable event such as an extended unscheduled nuclear unit outage, acts of God, acts of government, acts of nature, and acts of war. Second, this unpredictable event must cause a natural gas-fired or residual oil-fired generation variance of greater than or equal to +45 percent

or less than or equal to -30 percent from FPL's forecasts.

Q What are the less favorable features of FPL's proposal?

A FPL's proposal has the following less favorable features:

1. FPL has not submitted a comprehensive plan prior to or concurrent with its proposal;
2. FPL's proposal seeks to recover the balance of its natural gas and residual oil requirements based on a spot index price. A stated goal of FPL's procurement efforts is to obtain natural gas and residual fuel at below-spot market prices. This feature does not create any value to FPL's ratepayer, and only rewards FPL for actions that would have occurred regardless of any incentive;
3. FPL's proposal seeks to recover a risk premium as a component of the fixed price FPL will guarantee to its ratepayers. This risk premium would compensate FPL for the timing, volume, and execution risks associated with setting a fixed price for its ratepayers. While such risks exist, FPL's proposal does not include any quantitative analysis about the price volatility that exists within the natural gas and residual oil markets;
4. FPL's proposal does not indicate how FPL would determine the fixed price for natural gas and residual oil that FPL would guarantee to its ratepayers;
5. FPL's proposal does not indicate how FPL would set the pre-determined percentage of its natural gas and residual oil

requirements;

6. FPL's proposal suggests that the Commission authorize FPL to recover approximately $3 million in capital costs and $1 million in incremental operation and maintenance (O&M) costs annually through the fuel clause;

7. Currently, FPL records its actual natural gas and residual oil costs on its Schedules A3-A5. Under FPL's proposal, FPL would no longer record actual natural gas and residual oil costs on these schedules. The Commission should remain informed about FPL's proposal's effectiveness by comparing FPL's actual costs with the costs recovered from the ratepayers;

8. FPL's proposal allocates 20 percent of the *gains* from all non-separated wholesale energy sales, except emergency sales, and 20 percent of the savings from all wholesale energy purchases to its shareholders;

9. Under the FPL proposal's implementation schedule, the Commission and other parties do not have an opportunity to put forth an alternative to FPL's proposed stipulation; and

10. FPL has represented that its proposal's size and shape may change on an annual basis. Essentially, the Commission would authorize FPL to have an incentive, any incentive, and the details on the size and shape of this incentive could change on an annual basis.

Q What is your opinion of FPL's proposal?

A In its current form, the Commission should reject FPL's proposal. The structure of FPL's proposal does not reasonably share the benefits and costs of finding a balance between minimizing fuel costs and minimizing fuel cost volatility between FPL's ratepayers and shareholders.

Q What are the more favorable features of Florida Power's proposal? Please explain.

A Florida Power's proposal has the following more favorable features:

1. Florida Power will establish a fixed price for a pre-determined volume of its natural gas and residual oil requirements. Any difference between these fixed price and Florida Power's actual costs will accrue to its shareholders;
2. Florida Power will calculate the fixed price based on a mechanistic formula that the Commission can easily monitor and duplicate; and
3. Florida Power characterizes its proposal as a two-year pilot program during which Florida Power, the other parties, and the Commission can gain experience in financial hedging transactions.

Q What are the less favorable features of Florida Power's proposal?

A Florida Power's proposal has the following less favorable features:

1. Florida Power has not submitted a comprehensive plan prior to or concurrent with its proposal;
2. Florida Power's proposal seeks to recover a risk premium as a component of the fixed price Florida Power will guarantee

to its ratepayers. This risk premium would compensate Florida Power for the timing, volume, and execution risks associated with setting a fixed price for its ratepayers. While such risks exist, Florida Power's proposal does not include any quantitative analysis about the price volatility that exists within the natural gas and residual oil markets;

3. Florida Power's proposal does not indicate how Florida Power would set the pre-determined volume of natural gas and residual oil that Florida Power would hedge during a given calendar year;

4. Florida Power's proposal suggests that the Commission authorize Florida Power to recover approximately $10 million in capital costs and an unspecified amount in incremental O&M costs annually through the fuel clause;

5. Currently, Florida Power records its actual natural gas and residual oil costs on its Schedules A3-A5. Under Florida Power's proposal, Florida Power would no longer record actual natural gas and residual oil costs on these schedules. I believe that the Commission should remain informed about Florida Power's proposal's effectiveness by comparing Florida Power's actual costs with the costs recovered from the ratepayers; and

6. Florida Power's proposal allocates 33 percent of the gain from all non-separated wholesale energy sales and 33 percent of the savings from all wholesale energy purchases to its

shareholders.

Q What is your opinion of Florida Power's proposal?

A In its current form, the Commission should reject Florida Power's proposal. The structure of Florida Power's proposal does not reasonably share the benefits and costs of finding a balance between minimizing fuel costs and minimizing fuel cost volatility between Florida Power's ratepayers and shareholders.

Q What are the more favorable features of Gulf Power's proposal? Please explain.

A Gulf Power's proposal has the following more favorable features:

1. As a result of its hedging transactions, Gulf Power would allocate $3 in below-market savings to its ratepayers for every $1 that Gulf Power would retain for its shareholders. Therefore, Gulf Power's proposal aligns its shareholders' interests with its ratepayers' interests;
2. Gulf Power's proposal limits its ratepayers' above-market exposure to no more than 10 percent of Gulf Power's projected costs. Gulf Power's shareholders are responsible for any above-market exposure greater than 10 percent of Gulf Power's projected costs;
3. Gulf Power's proposal would limit its shareholder exposure to losses from its hedged positions to no more than five percent of the value of its forward 42-month projection;
4. Southern Company Services, who will implement Gulf Power's hedging program, has experience with hedging fuel

procurement transactions for Savannah Electric Power Company, Alabama Power Company, and Mississippi Power Company;

5. Gulf Power's proposal strikes a balance between two competing goals: minimizing fuel costs and minimizing fuel cost volatility; and

6. Gulf Power's proposal does not include a risk premium component.

Q What are the less favorable features of Gulf Power's proposal?

A Gulf Power's proposal has the following less favorable features:

1. Gulf Power has not submitted a comprehensive plan prior to or concurrent with its proposal;

2. Gulf Power's proposal does not indicate how Gulf Power would set the pre-determined percentage of its natural gas and oil requirements that Gulf Power would hedge during a given calendar year; and

3. Gulf Power's proposal suggests that the Commission authorize Gulf Power to recover an unspecified amount in capital costs and incremental O&M costs annually through the fuel clause.

Q What is your opinion of Gulf Power's proposal?

A As I have stated previously, the Commission should not authorize an explicit incentive to encourage each utility to pro-actively manage the risks associated with the utility's fuel procurement at this time. However, if the Commission determines that such an incentive is warranted, the structure of Gulf Power's proposal shares the benefits and costs of finding a balance between minimizing fuel costs and minimizing fuel cost volatility between Gulf Power's ratepayers and shareholders best among the three utilities' proposals.

ISSUE 7B: If the Commission were to approve any utility's incentive plan for optimally managing fuel price risk which includes a change in the method for calculating shareholder gains on wholesale sales as specified in Order Nos. PSC-00-1744-PAA-EI and PSC-01-2371-FOF-EI, what changes, if any, should be made to the requirements of these orders?

Q Can you describe the changes that FPL and Florida Power have included in their proposals for the Commission's shareholder incentive for wholesale energy sales as provided by Order Nos. PSC-00-1744-PAA-EI, in Docket No. 991779-EI, issued September 26, 2000, and PSC-01-2371-FOF-EI, in Docket No. 010283-EI, issued December 7, 2001, respectively (collectively, Order No. 00-1744)?

A Yes. Currently, the Commission allows each utility's shareholders to retain 20 percent of the gains on its non-separated wholesale energy sales, except for emergency sales, only for gains that exceed the utility's three-year moving average of gains from these sales. Moreover, the Commission requires each utility to allocate 100 percent of the savings from wholesale energy purchases to the utility's ratepayers. FPL's and Florida Power's proposals would allocate 20 and 33 percent, respectively, of all gains from non-separated, non-emergency wholesale energy sales and would allocate 20 and 33 percent, respectively, savings from wholesale energy purchases to its shareholders.

Q What were the amounts of gains from non-separated wholesale energy sales, excluding emergency sales, for FPL and Florida Power, respectively, during 2001?

A FPL and Florida Power received gains from non-separated wholesale energy sales, excluding emergency sales, of $17.0 million and $11.2 million, respectively, during 2001. However, neither FPL nor Florida Power exceeded their respective three-year moving averages of $37.9 million and $11.4 million. Therefore, FPL and Florida Power allocated all of the gains from these sales to their ratepayers during 2001.

Q What were the amounts of savings from wholesale energy purchases for FPL and Florida Power, respectively, during 2001?

A FPL and Florida Power received savings from wholesale energy purchases of $14.6 million and $4.0 million, respectively, during 2001.

Q What reasons did the Commission provide for establishing the current incentive mechanism for non-separated, non-emergency wholesale energy sales?

A On Page 11 of Order No. 00-1744, the Commission provided the following reasons for authorizing this current incentive mechanism:

> We find that this incentive structure will allow ratepayers: (1) to continue to receive the substantial cost reduction benefits achieved through the IOUs' current level of non-separated sales; and (2) to benefit from a credit to the fuel clause of 80 percent of the gains on non-separated sales above the threshold. This incentive structure also minimizes the possibility that the IOUs could be rewarded for behavior that is already occurring. The IOUs are rewarded only for performing better than they performed, on average, over the previous three year period. To the extent an IOU surpasses the threshold, its threshold will increase for

the next year. To the extent an IOU does not surpass the threshold, its shareholders will not receive as an incentive any portion of the gains that the IOU does achieve.

Q Why should the Commission not modify the shareholder incentive for non-separated wholesale energy sales as described by Order No. 00-1744?

A The Commission should not change this shareholder incentive for the following reasons:

1. FPL's and Florida Power's proposals represent nothing but an attempt to restate their arguments presented to the parties and Commission in several proceedings over several years prior to Order No. 00-1744.
2. No other party nor the Commission has indicated any desire to reconsider the size and/or shape of this shareholder incentive.
3. By Order No. 00-1744, the Commission provided for a shareholder incentive with a uniform size and shape among the utilities. Prior to Order No. 00-1744, each utility interpreted Order No. 12923 (predecessor to Order No. 00-1744) slightly differently which evolved into a shareholder incentive of non-uniform size and shape among the utilities. If the Commission approved one or both of FPL's and Florida Power's proposals, the Commission would regress back to a non-uniform shareholder incentive for wholesale energy transactions.
4. This shareholder incentive is operating as the Commission

intended. FPL's and Florida Power's ratepayers have experienced a reduction in fuel costs of $31.6 million and $15.2 million, respectively, in 2001 alone due to each utility's "normal" efforts to locate and dispatch the next available resource with the lowest marginal costs, regardless of that resource's owner. Once the utility has created additional value beyond its normal efforts, its shareholders retain 20 percent of this additional value. Moreover, if a utility falls short of its three-year moving average in one year, the threshold amount will be reduced in the following year.

5. This shareholder incentive became effective January 1, 2001 by Order No. PSC-00-2385-FOF-EI, in Docket No. 000001-EI, issued December 12, 2000. Therefore, the parties and the Commission have only one full year of data to analyze the impact this shareholder incentive has on ratepayers and shareholders. No person can analyze one data point, and reasonably conclude a change to the size or shape of this shareholder incentive is necessary and appropriate at this time.

ISSUE 2: What is the appropriate regulatory treatment for gains and losses an investor-owned electric utility incurs from hedging fuel and purchased power transactions through futures contracts?

ISSUE 3: What is the appropriate regulatory treatment for the premiums an investor-owned electric utility receives and pays for hedging fuel and purchased power transactions through options contracts?

ISSUE 4: What is the appropriate regulatory treatment for the transaction costs an investor-owned electric utility incurs from hedging its fuel and purchased power transactions through futures and options contracts?

Q What is the appropriate regulatory treatment for gains and losses from hedging a utility's fuel transactions through exchange-traded future contracts?

A The Commission should allow recovery through the fuel clause of gains and losses from exchange-traded futures contracts made pursuant to a Commission-approved plan to hedge natural gas, coal, residual oil, distillate oil, and wholesale energy prices.

Q What is the appropriate regulatory treatment for premiums received and paid for hedging a utility's fuel transactions through exchange-traded options contracts?

A The Commission should allow recovery through the fuel clause of premiums received and paid for exchange-traded options contracts made pursuant to a Commission-approved plan to hedge natural gas, residual oil, distillate oil, and wholesale energy prices.

Q What is the appropriate regulatory treatment for net settlement proceeds for hedging a utility's fuel transactions through swap contracts?

A The Commission should allow recovery through the fuel clause of net settlement proceeds for swap contracts made pursuant to a Commission-approved plan to hedge natural gas, residual oil, distillate oil, and wholesale energy prices.

Q What is the appropriate regulatory treatment for the transactions costs associated with a utility hedging its fuel transactions with futures, swap, and options contracts?

A The Commission should allow recovery through the fuel clause of transaction fees to non-affiliated entities associated with futures, swap, and options contracts made pursuant to a Commission-approved plan to hedge natural gas, coal, residual oil, distillate oil, and wholesale energy prices. The Commission will review such expenditures to affiliated entities on a case-by-case basis.

Q Does this conclude your testimony?

A Yes.

Exhibit TFB-1 (Page 1 of 1)

INVESTOR-OWNED ELECTRIC UTILITIES' NATURAL GAS-FIRED

ELECTRIC GENERATION: 1991, 2001, AND 2011

(GWH)	1991	2001	2011
Florida Power Corp.	149/<1%	5,764/14%	16,091/32%
Florida Power & Light	12,871/18%	24,496/25%	84,556/66%
Gulf Power Company	14/<1%	127/1%	3,281/26%
Tampa Electric Company	10/<1%	311/2%	10,278/43%
Note: Values for 1991 and 2001 are actual; values for 2011 are forecasted; percent values represent natural gas-fired generation as a percent of net energy for load			
Source: Utilities' 1992 and 2002 Ten Year Site Plans			

HISTORY OF RISK MANAGEMENT

An essential component of the human condition is the need and desire to manage the risk that he may encounter in his daily life. Since the beginning of time, one could classify each individual into one of two groups: risk-seeking and risk-averse. An individual who *speculates* seeks out risk for potential financial gain. An individual who hedges avoids risk and values certainty over his cash flow more than potential financial gain. To illustrate how an individual may manage risks that he encounters on a daily basis, I provide the following examples. On any given day, I may send a premium to an insurance company to protect against loss for my life, health, home, or automobile. Also, if I plan to walk outside and a high probability of rain exists, I will choose to carry an umbrella with me. Finally, I have allocated funds that I have set aside for my retirement to several types of investments, instead of placing all of my funds into a single investment. These examples show that identifying, quantifying, and managing risks that an individual may encounter is an intrinsic part of life.

As the rule of law spread throughout the world, a seller (e.g., wheat farmer) could enter into a *forward contract* with a buyer (e.g., bakery) at the beginning of the growing season for a specific quantity of wheat at a specific price on a specific delivery date at a specific delivery location. This contract provided both the wheat farmer and the bakery more certainty over the following: 1) the quantity of wheat the farmer would deliver to the bakery; 2) the location and timing of delivery; and 3) the price that the bakery would pay the farmer for his wheat.

As commerce increased, buyers and sellers created central marketplaces to facilitate trade with standardized terms and conditions, except for the price. In the United States, buyers and sellers created approximately 1,600 such marketplaces during the nineteenth century near major railheads, inland water ports, and seaports. In 1872, dairy merchants in New York created the Butter and Cheese Exchange of New York to bring order to the chaotic marketplace that existed then. As this exchange became successful, the exchange increased the number of products traded, such as eggs, poultry, and dried fruits. In 1882, the exchange changed its name to the New York Mercantile Exchange (NYMEX). During the next 120 years, the NYMEX, through a series of consolidations and mergers with other exchanges, has offered futures and options contracts for numerous precious metals and energy commodities.

ESTABLISHMENT AND MODIFICATION TO FUEL AND PURCHASED POWER COST RECOVERY CLAUSE

By Chapter 366, Florida Statutes, the Legislature delegated its authority to set rates for each utility to the Commission. As an exercise of its ratemaking authority, the Commission established and modified the fuel clause through a series of orders as the mechanism to recover a utility's prudently-incurred fuel costs on a dollar-for-dollar basis. I have traced the origins of the current fuel and purchased power cost recovery clause (fuel clause) to Order No. 9273, Docket No. 74680-CI, issued March 7, 1980. This order authorizes each utility to collect a levelized factor to recover fuel and purchased power costs (fuel costs), adjusted for any over- or under-recovery of costs during the previous period, over a six-month projected period. In addition, the utility would pay (receive) interest at the commercial paper rate for any over-recovery (under-recovery) of fuel costs.

The Commission has substantially modified the fuel clause on five occasions since 1980. First, the Commission mandated that each utility would credit 80 percent of the gains from its *economy energy* sales to the fuel clause by Order No. 12923, in Docket No. 830001-EU-B, issued January 24, 1984. The remaining 20 percent of these gains would accrue to the utility's shareholders. Previously, the Commission would estimate gains from these sales during a base rate proceeding and adjust the utility's revenue requirements accordingly.

Second, the Commission provided each party the opportunity for a "mid-course correction" to a utility's fuel factor when the utility experiences a greater than 10 percent positive or negative variance between fuel revenues and costs by Order No. 13694, in Docket No. 840001-EI-B, issued September 24, 1984.

Third, the Commission standardized the types of fuel costs eligible for recovery through the fuel clause by Order No. 14546, in Docket No. 850001-EI-B, issued July 8, 1985. This order provides clear regulatory guidance about whether a utility can recover a cost through base rates or the fuel clause.

Fourth, the Commission lengthened the recovery period from six to twelve months by Order No. PSC-98-0691-FOF-PU, in Order No. 980269-PU, issued May 19, 1998. The Commission re-affirmed this decision by Order No. PSC-01-1665-PAA-EI, in Docket No. 010001-EI, issued August 15, 2001.

Fifth, the Commission modified the shareholder incentive provisions established in Order No. 12923 for economy energy sales. The Commission stated that a utility's shareholders would receive 20 percent of the gains from all non-separated wholesale energy sales, except for emergency sales, after the utility exceeds the previous three year moving average of gains (threshold) from these sales by Order No. PSC-00-1744-PAA-EI, in Docket No. 991779-EI, issued September 26, 2000.

COMPONENTS OF A UTILITY'S FUEL PROCUREMENT RISK MANAGEMENT PLAN

When a utility files its fuel procurement risk management plan with the Commission, this plan should include information regarding the following components:

1. Identify overall quantitative and qualitative risk management objectives;
2. Identify minimum quantity of fuel to be hedged;
3. Identify and quantify each risk, general and specific, that the utility may encounter with its fuel procurement;
4. Describe the utility's oversight of its fuel procurement activities;
5. Verify that the utility provides its fuel procurement activities with independent and unavoidable oversight;
6. Describe the utility's corporate risk policy regarding fuel procurement activities;
7. Verify that the utility's corporate risk policy clearly delineates individual and group transaction limits and authorizations for all fuel procurement activities;
8. Describe the utility's strategy to fulfill its risk management objectives;
9. Verify that the utility has sufficient policies and procedures to implement its strategy;
10. Indicate the number and type of personnel who are responsible for fulfilling the utility's risk management objectives;
11. Verify that the utility has a sufficient number and type of personnel who can fulfill its risk management objectives.
12. Describe the utility's cost effective response to each general and specific risk associated with its fuel procurement;
13. Describe the utility's reporting system for fuel procurement activities;
14. Verify that the utility's reporting system consistently and comprehensively identifies, measures, and monitors all forms of risk associated with fuel procurement activities; and
15. If the utility has current limitations in implementing certain hedging techniques that would provide a net benefit to ratepayers, provide the details of a plan for developing the resources, policies, and procedures for acquiring the ability to use effectively the hedging technique.

Total Fuel Cost Statistical Measures for Florida Power & Light, Company, Florida Power Corporation, Gulf Power Company, and Tampa Electric Company: July 1996 through June 2001

cents per kwh	FPL	FPC	GULF	TECO
Average	2.07	2.08	1.73	2.10
Standard Deviation	0.59	0.37	0.18	0.14
Mid-course corrections	3	4	0	2
Source: Monthly Schedule A3 for each utility from July 1996 - June 2001				

The data in this table indicate the costs and cost volatility that each utility experienced in its monthly total fuel costs from July 1996 through June 2001. When reading data in this table, higher values in the "average" row indicate that the utility recovered higher fuel costs from its ratepayers. Also, higher values in the "standard deviation" row indicate that the utility experienced higher fuel cost volatility.

The table also indicates the number of mid-course corrections that the Commission approved for each utility during this time period. A utility's ratepayers experience the utility's fuel cost volatility most directly and immediately through a mid-course correction. Generally speaking, a utility which experiences high fuel cost volatility will seek mid-course corrections from the Commission more frequently.

COMPARISON OF "HIGH BILL" COMPLAINTS FILED WITH COMMISSION

	Complaints: Jan00 - Jun00	Complaints: May01 - Oct01	% Change
Florida Power & Light	32	142	344%
Florida Power	16	57	256%
Tampa Electric	12	25	108%
Source: Commission's Division of Consumer Affairs			

During the period June 2000 through April 2001, the rates for the three largest utilities rose substantially for all rate classes. A residential customer of Florida Power & Light Company (FPL) who uses 1,000 kilowatt-hour monthly (typical residential ratepayer) experienced a 26 percent increase in his total bill during this time period. Typical residential ratepayers for Florida Power Corporation (Florida Power) and Tampa Electric Company (Tampa Electric) experienced 12 percent and seven percent increases in their total bills during this time period, respectively.

I attribute most of these total bill increases to an increase in each utility's fuel factor. I believe that a utility's ratepayers are sensitive to changes in the utility's rates. As I illustrate in the table above, the Commission experienced sharp increases in "high bill" complaints from each utility's ratepayers. A reasonable person can infer from these data that a utility's ratepayers value rate stability.

EXAMPLE OF A UTILITY ENGAGING IN FUTURES CONTRACTS TO HEDGE ITS NATURAL GAS COSTS

A utility can hedge its natural gas costs with exchange-traded futures contracts. In a small minority of futures contracts purchased, a utility would purchase and receive delivery of a commodity, such as natural gas, through futures contracts in the following manner. Assume a utility wishes to hedge 25 percent of its December 200X natural gas requirements (four million MMBtu) on August 7, 200X. Because one NYMEX natural gas futures contract is equivalent to 10,000 MMBtu, the utility instructs its broker to purchase 400 natural gas futures contracts at the NYMEX for December 200X delivery at either a specific price, the prevailing market price, or no more than a maximum price. Assume that the broker bought these 400 futures contracts for an average price of $2.50 per MMBtu.

During the month prior to delivery, the utility informs the NYMEX that the utility wishes to receive delivery of its four million MMBtu at the contract's delivery point, Henry Hub in Louisiana. The NYMEX then matches the utility's 400 futures contracts with one or more sellers who can deliver four million MMBtu of natural gas during December. Once the utility has received delivery of its natural gas, the utility pays NYMEX $10 million for the natural gas ($2.50 per MMBtu x four million MMBtu). Then, NYMEX compensates the seller(s) based upon the price of the December 200X natural gas futures contract when the seller(s) sold its(their) contracts.

However, in the overwhelming majority of futures contracts purchased, the buyer executes an offsetting trade to close out his position prior to receiving delivery of the commodity. For example, the price of a natural gas futures contract for December delivery is $2.50 per MMBtu on August 7, 200X. The price for natural gas on the spot market is $2.70 per MMBtu. Utility A which anticipates burning at least 100,000 MMBtu of natural gas in December purchases 10 natural gas contracts. Utility A had previously entered into a contract with Supplier X to receive 100,000 MMBtu with the price indexed to the spot market. Utility A has now established its natural gas costs at $2.50 per MMBtu regardless the direction of natural gas prices between August 7 and the last trading day of the December 200X natural gas futures contracts. The following two scenarios demonstrate:

Scenario 1 - Prices Rise

On November 25, 200X, the price of a natural gas futures contract for December delivery has risen to $3.00 per MMBtu. The price for natural gas on the spot market is also $3.00 per MMBtu. Supplier X delivers 100,000 MMBtu of natural gas to Utility A at $3.00 per MMBtu. However, Utility A sells its 10 natural gas futures contracts at $3.00 per MMBtu, a $0.50 per MMBtu gain in the futures market. Therefore, Utility A's effective natural gas price in December is $2.50 per MMBtu.

Date	Cash Market	Futures Market
August 7, 200X		Purchases 10 contracts for Dec delivery at $2.50 per MMBtu
November 25, 200X	Purchases 100,000 MMBtu of natural gas at $3.00 per MMBtu	Sells 10 contracts for Dec delivery at $3.00 per MMBtu

Scenario 2 - Prices Fall

On November 25, 200X, the price of a natural gas futures contract for December delivery has fallen to $2.25 per MMBtu. The price for natural gas on the spot market is also $2.25 per MMBtu. Supplier X delivers 100,000 MMBtu of natural gas to Utility A at $2.25 per MMBtu. However, Utility A sells its 10 natural gas futures contracts at $2.25 per MMBtu, a $0.25 per MMBtu loss in the futures market. Therefore, Utility A's effective natural gas price in December is $2.50 per MMBtu.

Date	Cash Market	Futures Market
August 7, 200X		Purchases 10 contracts for Dec delivery at $2.50 per MMBtu
November 25, 200X	Purchases 100,000 MMBtu of natural gas at $2.25 per MMBtu	Sells 10 contracts for Dec delivery at $2.25 per MMBtu

EXAMPLE OF A UTILITY ENGAGING IN OPTIONS CONTRACTS TO HEDGE ITS NATURAL GAS COSTS

A utility can hedge its natural gas costs with exchange-traded options contracts. In a small minority of options contracts purchased, a utility would purchase and receive delivery of a commodity, such as natural gas, through *call* options contracts in the following manner. A utility would purchase and receive delivery of a commodity, such as natural gas, through an options contract in the following manner. Assume that the same utility in TFB-7 wishes to hedge an additional 500,000 MMBtu of its December 200X natural gas requirements on August 7, 200X in case residual oil prices are more expensive than natural gas for December 200X delivery. Because one NYMEX natural gas options contract is equivalent to 10,000 MMBtu, the utility would instruct its broker to purchase 50 natural gas call options contracts at the NYMEX for December 200X delivery at a specific strike price at either a specific premium, the prevailing market premium, or no more than a maximum premium. Further, assume that the broker bought these 50 contracts with a $2.50 per MMBtu strike price for an average premium of $0.06 per MMBtu. The utility now has the right, but not the obligation, to purchase 500,000 MMBtu of natural gas at $2.50 per MMBtu for December 200X delivery through the NYMEX. The utility would pay $30,000 to NYMEX for this right. Let's assume that it is now November 1, 200X. The utility needs those additional 500,000 MMBtu of natural gas, and instructs its broker to exercise its 50 options contracts. The utility now owns 50 additional natural gas futures contracts at a price of $2.50 per MMBtu. From this time until delivery of the natural gas, the process is similar to what I described in TFB-7.

Also, remember that the utility bought the right for $30,000 to purchase 500,000 MMBtu of natural gas at $2.50 per MMBtu for December 2002 delivery through the NYMEX. Assume that the utility does not need those extra 500,000 MMBtu of natural gas after all. The utility can either close out its position with an offsetting trade or allow its options to expire worthless. Even if the options expire worthless, the utility may have acted in the most cost effective manner to acquire those extra 500,000 MMBtu of natural gas.

However, in the overwhelming majority of options contracts purchased, the buyer executes an offsetting trade to close out his position prior to receiving delivery of the commodity. For example, the price of a natural gas futures contract for December delivery is $2.50 per MMBtu on August 7, 200X. The price for natural gas on the spot market is $2.30 per MMBtu. Utility A which anticipates burning at least 100,000 MMBtu of natural gas in December purchases 10 natural gas call options contracts at $0.05 per MMBtu premium. Utility A will exercise these call options if the price on the last trading day for December natural gas delivery is greater than $2.55 per MMBtu. Otherwise, these call options will expire worthless. Utility A had previously entered into a contract with Supplier X to receive 100,000 MMBtu with the price indexed to the spot market. Utility A has now established its natural gas costs at no greater than $2.55 per MMBtu regardless the direction of natural gas prices between August 7 and the last trading day of the December 200X natural gas contracts. The following two scenarios demonstrate:

Scenario 1 - Prices Rise

On November 25, 200X, the price of a natural gas futures contract for December delivery has risen to $3.00 per MMBtu. The price for natural gas on the spot market is also $3.00 per MMBtu. Supplier X delivers 100,000 MMBtu of natural gas to Utility A at $3.00 per MMBtu. However, Utility A exercises its 10 natural gas call options contracts at $2.50 per MMBtu and then sells its 10 natural gas contracts at $3.00 per MMBtu. This action results in a $0.50 per MMBtu gain in the futures market. Therefore, Utility A's effective natural gas price in December is $2.55 per MMBtu.

Date	Options Market	Cash Market	Futures Market
August 7, 200X	Purchases 10 natural gas $2.50 call options at $0.05 per MMBtu		
November 25, 200X	Exercises 10 natural gas $2.50 call options	Purchases 100,000 MMBtu of natural gas at $3.00 per MMBtu	Sells 10 contracts for Dec delivery at $3.00 per MMBtu

Scenario 2 - Prices Fall

On November 25, 200X, the price of a natural gas futures contract for December delivery has fallen to $2.25 per MMBtu. The price for natural gas on the spot market is also $2.25 per MMBtu. Supplier X delivers 100,000 MMBtu of natural gas to Utility A at $2.25 per MMBtu. However, Utility A does not exercise its 10 natural gas call options because the spot price is less than the strike price. Utility A allows these options to expire worthless. Therefore, Utility A's effective natural gas price in December is $2.30 per MMBtu.

Date	Options Market	Cash Market	Futures Market
August 7, 200X	Purchases 10 natural gas $2.50 call options at $0.05 per MMBtu		
November 25, 200X	Allows the 10 natural gas $2.50 call options to expire worthless	Purchases 100,000 MMBtu of natural gas at $2.25 per MMBtu	

EXCERPTS FROM ORDER NO. 14546, DOCKET NO. 850001-EI-B,
ISSUED JULY 8, 1985, PAGES 4-5

As a result of [the Commission's] determinations in this proceeding, prospectively, the following charges are properly considered in the computation of the average inventory price of fuel used in the development of fuel expense in the utilities' fuel cost recovery clauses:

1. The invoice price of fuel.
2. Any revisions to the invoice price.
3. Any quality and/or quantity adjustments to the invoice price.
4. Transportation costs to the utility system, including detention or demurrage.
5. Federal and state taxes and purchasing agents' commissions.
6. Port charges.
7. All quantity and/or quality inspections performed by independent inspectors.
8. All additives blended with fuel prior to burning or injected into the boiler firing chamber along with fuel.
9. Inventory adjustments due to volume and/or price adjustments.
10. Fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers. Recovery of such costs should be made on a case-by-case basis after Commission approval.

The following types of fossil fuel-related costs are more appropriately considered in the computation of base rates:

1. Operations and maintenance expenses at generating plants or system storage facilities. This includes unloading and fuel handling costs at the generating plant or storage facility.
2. Transportation charges between dedicated storage facilities and generating plants.
3. Fuel procurement administrative functions.
4. Fuel additives neither blended with fuel prior to burning nor injected into the boiler firing chamber along with fuel.

DEFINITION AND HYPOTHETICAL EXAMPLE OF EACH TYPE OF RISK THAT A UTILITY MAY EXPERIENCE WITH ITS FUEL PROCUREMENT TRANSACTIONS

Event risk is the uncertainty related to the occurrence of random events. An example of a hypothetical event risk is: During the months of August and September of each year, the probability that a tropical storm or hurricane may develop in or move into natural gas-producing areas of the Gulf of Mexico is high. When this events occurs, natural gas prices experience a short-term increase.

Price risk is the uncertainty related to the market value of assets and liabilities, both physical and financial. An example of a hypothetical price risk is: The market price of natural gas changes instantaneously 24 hours per day, 365 days per year due to political, economic, weather, and random events.

Basis risk is the uncertainty related to price fluctuations between two different products, locations, or time periods. An example of a hypothetical basis risk is: The price difference between natural gas at Henry Hub in Louisiana and natural gas in the Florida Gas Transmission zone that Utility X is located changed from five cents to ten cents.

Counterparty risk is the uncertainty related to performance in payment or delivery by a counterparty. An example of a hypothetical counterparty risk: Supplier Y defaulted on its contract with Utility X to provide 100,000 MMBtu of natural gas per day. Utility X replaced this natural gas with a spot market purchase at a price 25 cents above the market price.

Modeling risk is the uncertainty related to inaccurate or incorrect forecasts. An example of a hypothetical modeling risk is: The model that Utility X uses to model the economic dispatch of its system consistently underestimates the amount of Utility X's natural gas-fired generation. Until Utility X recognizes and corrects this model's error, Utility X must purchase natural gas on the spot market at the last minute at 20 cents higher than the market price.

Volume risk is the uncertainty related to a numerical difference between the utility's scheduled energy supply and forecast load. An example of a hypothetical volume risk is: The afternoon maximum temperature in Utility X's major population center was 103 degrees Fahrenheit on July 24, 2002. Utility X's natural gas-fired generation for that day was 20 percent higher than expected.

Shaping risk is the uncertainty related to a timing difference between the utility's scheduled energy supply and forecast load. An example of a hypothetical shaping risk is: Assume that Utility X's meteorologist correctly forecasted July 24, 2002's afternoon maximum temperature of 103 degrees Fahrenheit in Utility X's major population center. On the previous day, Utility X projected that an additional 100 MW would be needed for its system between 2:00 P.M. and 6:00 P.M. the following day. Utility X purchased 100 MW of must-run wholesale energy from Merchant Plant Z for the hours of 6:00 A.M. to 6:00 P.M. Although this 100 MW wholesale energy purchase satisfied Utility X's incremental demand in the afternoon, this must-run purchase also displaced otherwise economic natural gas-fired generation in Utility X's dispatch queue from 6:00 A.M. to 9:00 A.M.

TYPES OF HEDGING TECHNIQUES

Physical

When a utility enters a contract with one or more counterparties to accept delivery of a specified amount of fuel, the utility is employing a physical hedging technique. A utility can implement physical hedging techniques to respond cost effectively to **price, basis, volumetric, and shaping** risks that a utility may encounter with fuel procurement.

A utility can enter a contract with one or more counterparties to accept fuel for a fixed price to manage **price and basis** risk. When a utility enters a fixed price contract for fuel, the seller assumes the inherent risks associated with changes in the fuel price and basis from the date the contract is signed to the end of the contract. However, the utility knows its costs for that fuel quantity during that period with certainty.

On the other hand, the utility loses the opportunity to take advantage of any fuel price decrease. When a utility enters a fixed price contract for fuel, the utility should negotiate with as much information available to the utility at that time. However, unforeseen events may cause the fuel price on the spot market to decline from the date the contract is signed to the end of the contract. If the utility enters a fixed price contract with as much information as possible, a potential decline in the spot market price is acceptable in return for certain fuel prices.

A utility can also enter a contract with one or more counterparties to accept a specified quantity of fuel to manage **volumetric** risk. This contract will provide the utility certainty that the utility has a specified fuel quantity at its generating units. However, some counterparties may insist upon a "take-or-pay" clause in its contract with a utility. A "take-or-pay" clause essentially states that the utility must accept delivery or pay for a minimum amount of fuel during a given time period. Under the appropriate circumstances, a "take-or-pay" clause is acceptable in return for a specified fuel quantity.

A utility can enter a contract with one or more counterparties with an options to make or accept delivery of a specified quantity of fuel to manage **shaping** risk. These contracts will provide the utility with more flexibility to match its load with its system resources. For example, let's assume that Utility X has a sufficient supply of natural gas and residual oil for its system resources under most likely load and fuel price forecasts. However, if natural gas prices rise relative to residual oil, Utility X will have too much natural gas and not enough residual oil as Utility X dispatches its residual oil-fired assets more frequently than its natural gas-fired assets. In this instance, Utility X should have contracts in place to purchase additional residual oil as needed. Also, Utility X should explore all opportunities to sell its excess natural gas to another entity.

Operational

When a utility has appropriate policies, procedures, and personnel in place to manage the internal risks associated with fuel procurement, the utility is employing operational hedging techniques. A utility can implement operational hedging techniques to respond cost effectively to **event, counterparty, and modeling** risks that a utility may encounter with fuel procurement.

To manage **event** risk, a utility should have an established, written policy of the utility's cost effective countermeasures for each identified contingent event. A utility should have established, written procedures that instruct its personnel how and when to implement these countermeasures. A utility should recruit, hire, train, motivate, and retain a sufficient number of personnel who can identify these contingent events, design cost effective countermeasures for each contingent event, and implement these countermeasures when appropriate.

To manage **counterparty** risk, a utility should have an established, written policy of entering fuel procurement contracts only with counterparties who can pay for or deliver the specified fuel quantity in a timely manner. A utility should have established, written procedures that instruct its personnel how to ascertain whether a counterparty can pay for or deliver the specified fuel quantity in a timely manner. A utility should recruit, hire, train, motivate, and retain a sufficient number of personnel who can ascertain whether a counterparty can pay for or deliver the specified fuel quantity in a timely manner.

To manage **modeling** risk, a utility should have an established, written policy for designing, testing, and updating engineering, economic, and weather models to generate timely, accurate forecasts. A utility should have established, written procedures that instruct its personnel for designing, testing, and updating its engineering, economic, and weather models. A utility should recruit, hire, train, motivate, and retain a sufficient number of personnel who can design, test, and update engineering, economic, and weather models to generate accurate and precise forecasts.

Financial

When a utility enters into a futures, swap or options contract to initiate action with the specific intent of protecting an existing or anticipated physical market exposure from unexpected or adverse price fluctuations.

A utility can implement financial hedging techniques to respond cost effectively to **price, counterparty, volumetric, and shaping** risks that a utility may encounter with fuel procurement.

To manage **price** risk, a utility can set the price that the utility will pay for a given fuel by opening a *long* position on one or more futures or options contract. When a utility enters a futures contract for fuel, the utility knows its costs for that fuel quantity during that period with certainty.

On the other hand, the utility loses the opportunity to take advantage of any fuel price decrease. When a utility enters a futures contract for fuel, the utility should do so with as much information available to the utility at that time. However, unforeseen events may cause the fuel price on the spot market to decline from the date the futures contract is entered to the delivery date. If the utility enters a futures contract with as much information as possible, a potential decline in the spot market price is acceptable in return for certain fuel prices.

To manage **counterparty** risk, the utility knows that the commodity exchange becomes the counterparty for each individual or firm which opens a long or *short* position in a given commodity. Backed by its clearing members, the NYMEX provides assurance of delivery for those who hold long positions and payment for those who hold short positions.

To manage **volumetric** risk, a utility can open a long position on one or more futures or options contracts with a commodity exchange to accept a specified quantity of fuel. The fuel price associated with such contracts will be set based on price paid for the futures contracts or the strike price for the options contracts. The commodity exchange will match up the utility with an individual or firm who holds a short position and arrange fuel delivery at the specified location during the delivery month. These contracts will provide the utility certainty that the utility has a sufficient fuel supply at its generating units.

To manage **shaping** risk, a utility can enter an options contract to make (put) or accept (call) delivery of a specified quantity of fuel. An options contract will provide the utility with more flexibility to match its load with its system resources. For example, let's assume that Utility X has a sufficient supply of natural gas and distillate oil for its system resources under most likely load and fuel price forecasts. However, if natural gas prices rise relative to distillate oil, Utility X will have too much natural gas and not enough distillate oil as Utility X dispatches its distillate oil-fired assets more frequently than its natural gas-fired assets. In this instance, Utility X should have purchased distillate oil calls to set a maximum price for any additional distillate oil purchases as-needed. Also, Utility X should buy natural gas puts to set a minimum price for sales of any excess natural gas.

GLOSSARY OF TERMS USED IN TESTIMONY AND EXHIBITS

Complete risk management plan: Commission staff will make an affirmative statement that a utility's risk management plan contains all of the components listed in TFB-4. An affirmative statement of completeness does not imply agreement or approval of these components.

Dollar-for-dollar basis: the Commission has authorized each utility to recover each dollar the utility spends on prudent fuel and purchased power costs through the fuel clause. The Commission defers any difference between a utility's fuel revenues and fuel costs to the following recovery period(s).

Economy energy sale: a non-firm, short-term wholesale energy sale in which the buyer can purchase energy from the seller at a lower price than the buyer can generate the energy. These sales are made for economic, not reliability, reasons.

Ex ante: (Latin) before the fact.

Fixed price mechanism: a fixed price forward contract, a futures contract, an options contract, or floating-for-fixed swap contract.

Forward contract: a unique contractual arrangement to make or accept delivery between two or more counterparties of a specified product at a specified price with unique terms and conditions.

Futures contract: a standardized contractual arrangement to make or accept delivery between a party and an exchange of a specified commodity at a specified price with standardized terms and conditions.

Gains: as implied in Order No. 12923, the difference between the midpoint of the seller's incremental costs and the buyer's decremental costs and the seller's incremental costs. The Commission re-defined gains as the difference between incremental revenues and incremental costs of a non-separated wholesale energy sale by Order No. 00-1744.

Hedge: the initiation of an action with the specific intent of protecting an existing or anticipated physical market exposure from unexpected or adverse price fluctuations.

Long: the market position of a party who has purchased a futures or options contract.

Options contract: a standardized contractual arrangement which provides the buyer the right, but not the obligation, to purchase (**call**) or to sell (**put**) the underlying futures contract at a specified price with standardized terms and conditions in exchange for a one-time premium payment. The contract also requires the seller, who receives the premium, to meet this obligation.

Perfect hedge: the initiation of an action with the specific outcome of protecting 100 percent of an existing or anticipated physical market exposure from unexpected or adverse price fluctuations.

Short: the market position of a party who has sold a futures or options contract.

Speculation: the initiation of an action with the specific intent to profit from the specific directional price move of a commodity.

Standard deviation: a measure of volatility. The square root of the arithmetic average of the squares of the difference between each data point and the mean within a data series.

Swap: a contractual agreement between two parties to exchange cash flows at specified futures dates according to a prescribed manner. A **floating-for-fixed** swap occurs when a party exchanges a floating cash flow for a fixed cash flow. Conversely, a **fixed-for-floating** swap occurs when a party exchanges a fixed cash flow for a floating cash flow.