State of Florida

Public Service Commission

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-M-E-M-O-R-A-N-D-U-M-

DATE: JUNE 6, 2002

TO: DIRECTOR, DIVISION OF THE COMMISSION CLERK & ADMINISTRATIVE SERVICES (BAYÓ)

FROM: DIVISION OF ECONOMIC REGULATION (MCNULTY, BOHRMANN) RJ
OFFICE OF THE GENERAL COUNSEL (C. KEATING) WCK JDJ

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

AGENDA: 06/18/02 - REGULAR AGENDA - PROPOSED AGENCY ACTION - INTERESTED PERSONS MAY PARTICIPATE

CRITICAL DATES: NONE

SPECIAL INSTRUCTIONS: NONE

FILE NAME AND LOCATION: S:\PSC\ECR\WP\011605EI.RCM

CASE BACKGROUND

By Order No. PSC-01-0710-PCO-EI, issued March 21, 2001, in Docket 010001-EI, the Commission granted Florida Power Corporation's (FPC) February 9, 2001 petition for a mid-course correction to its fuel and purchased power cost recovery factors (factors) to collect an actual $29.4 million under-recovery for 2000 and a projected $73.0 million under-recovery for 2001.

The Commission granted FPC's petition for mid-course corrections for the following reasons. First, the Commission found the assumptions that FPC used to determine its estimated under-recovery amount to be reasonable. Second, the mid-course correction was expected to mitigate a more severe rate impact of FPC collecting its estimated under-recovery during 2002. Third, the mid-course correction was expected to reduce the interest expense that FPC's ratepayers would pay on the 2001 estimated under-recovery balances if those balances were recovered in 2002, instead of 2001. Finally, the mid-course correction was expected to allow FPC to recover the additional fuel and purchased power costs in a timely manner.

Although the Commission granted FPC's petition for mid-course correction the Commission did not state whether FPC had prudently incurred these incremental costs. The Commission indicated that any party or the Commission staff could raise issues regarding the prudence of these incremental costs, if necessary, at the hearing scheduled in Docket No. 010001-EI, commencing November 20, 2001.

During the discovery process, staff reviewed information related to whether FPC took all reasonable measures to mitigate the substantial increase in natural gas wellhead prices that occurred from March 1999 to March 2001. By Order No. PSC-01-1829-PCO-EI, in Docket No. 010001-EI, issued September 11, 2001, the Prehearing Officer identified the following issue:

> ISSUE 19D: For the period March 1999, to March 2001, did FPC take reasonable steps to manage the risks associated with changes in natural gas prices?

The parties and staff were preparing to address this issue at the hearing in that docket, commencing November 20, 2001. However, the Office of Public Counsel filed a motion to defer consideration of this issue as well as five other related issues on November 2, 2001. The Prehearing Officer granted this motion by Order No. PSC-01-2273-PCO-EI, in Docket No. 010001-EI, issued November 19, 2001. The Commission directed staff to open a new docket to address these six issues. Staff established Docket No. 011605-EI to address these six issues on November 27, 2001. The Prehearing Officer for this docket identified these six issues in the Order Establishing Procedure (OEP) issued in this docket (Order No. PSC-02-0192-PCO-EI, issued February 12, 2002.) With this recommendation, staff is seeking a proposed agency action Commission decision to resolve Issue 6 in the OEP (previously identified as Issue 19D in Docket No. 010001-EI).

At the May 21, 2002, Agenda Conference, the Commission approved Staff's recommendation on an identical issue as pertains to Florida Power & Light Company (FPL). Staff recommended the Commission recognize that FPL took reasonable steps to manage the risk associated with changes in natural gas prices based upon FPL's expectation of future changes in natural gas prices and the regulatory treatment of its fuel procurement activities.

DISCUSSION OF ISSUES

ISSUE 1: For the period March 1999 to March 2001, did FPC take reasonable steps to manage the risk associated with changes in natural gas prices?

RECOMMENDATION: Yes. Based upon FPC's expectations of future changes in natural gas prices and regulatory treatment of its fuel procurement activities, FPC took reasonable steps to manage the risk associated with changes in natural gas prices.

STAFF ANALYSIS: Staff presents its analysis in four parts: description of and reasons for increase in natural gas prices; regulatory treatment regarding financial hedging transactions; FPC's response to increase in natural gas prices; and staff's analysis of FPC's response.

Description of and Reasons For Increase in Natural Gas Prices

FPC generates a significant percentage of its electricity through natural gas-fired generation. The market price of natural gas changed substantially from March 1999 to March 2001. The monthly average price of natural gas at the wellhead (wellhead price) was $1.70 per 1,000 cubic feet (MCF) in March 1999. During 1999, the wellhead price did not exceed $2.68 per MCF. The wellhead price increased steadily throughout 2000 and reached a high of $8.06 per MCF in January 2001. By March 2001, the wellhead price dropped to $5.15 per MCF.

In the short term, weather has the largest impact on natural gas demand. Natural gas consumption for many applications is not sensitive to weather conditions. However, a colder-than-normal period during the winter can significantly impact space-heating demand for natural gas as a direct application and as a feedstock for the production of electricity. As the demand for natural gas increases, the wellhead price will increase. The months from November 2000 through March 2001 nationwide were seven percent colder-than-normal and 23 percent colder than a year earlier. Consequently, natural gas consumption by residential consumers (who are most weather sensitive) increased to 2,618 billion cubic feet (BCF) during this period, a 23 percent increase over the prior year's consumption levels.

Also, demand for natural gas-fired generation increased in the western United States during this period. Hydroelectric power serves a significant percentage of load in the western United States. During 2000, the Pacific Northwest experienced below normal amounts of rain and snow which impacted the amount of available hydroelectric power. Utilities called upon natural gas-fired generation to serve load that hydroelectric units would have otherwise served. This increase in natural gas-fired generation placed upward pressure on prices.

On the supply side of the equation, the wellhead price impacts the economic decisions that countless firms make regarding natural gas production and storage. For example, when the wellhead price is low, the incentive for firms to seek out new sources of natural gas is low. As the market price increases, so does the incentive for these firms to seek out new sources of natural gas. The wellhead price during 1999 was $2.19 per MCF. According to the United States Energy Information Administration, natural gas production nationwide totaled 18,832 BCF in 1999. One year later, the wellhead price rose to $3.69 per MCF, and natural gas production increased to 18,987 BCF. Last year, the wellhead price rose to $4.12 per MCF, and natural gas production increased to 19,355 BCF.

As 1998 ended, available natural gas in underground storage totaled 2,730 BCF which was approximately seven percent higher than the 25-year average and the most since 1991. During 1999, the industry experienced a normal pattern of seasonal withdrawals and injections. However, as wellhead prices started 2000 high and continued to rise steadily throughout the year, this trend had two impacts on available natural gas storage levels. First, owners of the natural gas in storage withdrew more gas than normal from storage to take advantage of the high wellhead prices. Second, these same owners injected less natural gas than normal in the hopes that wellhead prices would eventually fall before the winter. On November 1, 2000, available natural gas in storage was 2,732 BCF, a 24-year low for the start of the winter season. Then, as most areas in the contiguous 48 United States experienced much colder than normal weather in November and December, available natural gas storage fell to 742 BCF by March, 2001.

Regulatory Treatment Regarding Financial Hedging Transactions

Financial hedging is a term of art to describe the purchase or sale of an exchange-traded futures or options contract with the specific intent of protecting an existing or anticipated physical market position from unexpected or adverse price fluctuations. Although individuals and firms have reduced their exposure to price changes in agricultural products and precious metals for decades, if not centuries, through exchange-traded futures and options contracts, the New York Mercantile Exchange (NYMEX) did not offer a natural gas futures contract until 1990 or a natural gas options contract until 1992. Since 1992, the NYMEX has introduced other products, such as wholesale electricity and coal futures contracts, relevant to electric generation.

By Order No. 14546, issued July 8, 1985, in Docket No. 850001-EI-B, the Commission delineated whether a fuel-related expense is eligible for recovery through the fuel clause. This order states, in pertinent part:

> 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.

Because the Commission issued this order approximately five years prior to the NYMEX's introduction of the natural gas futures contract, these guidelines do not contemplate cash flows associated with financial hedging transactions. Until now, no party has requested a decision from the Commission asking whether and how a utility can charge and credit these cash flows to the fuel clause. If the Commission supplemented these guidelines set forth in Order No. 14546, each utility could engage in prudent financial hedging transactions with greater certainty of the regulatory treatment of such cash flows.

Since the advent of the fuel clause, the Commission has required each utility to purchase fuel prudently and reasonably. The Commission and the parties have typically interpreted prudent and reasonable costs as synonymous with minimizing fuel costs. However, no party has asked the Commission how much weight each utility should assign to minimizing <u>fuel cost volatility</u> in its fuel procurement transactions. Although one reason that the Commission may approve a party's request for a mid-course correction to a utility's fuel factor is to minimize rate shock (<u>see</u> Order No. PSC-01-0963-PCO-EI, in Docket No. 010001-EI, issued April 18, 2001), a mid-course correction impacts the <u>rate</u> that a utility's ratepayers pay, not the <u>cost</u> that the utility incurs to purchase the fuel to generate electricity.

Staff has identified the following issues in this docket that allow the Commission to supplement the guidelines set forth in Order No. 14546:

Issue 2: What is the appropriate regulatory treatment for gains and losses from hedging an investor-owned electric utility's fuel transactions through futures contracts?

Issue 3: What is the appropriate regulatory treatment for the premiums received and paid for hedging an investor-owned electric utility's fuel transactions through options contracts?

Issue 4: What is the appropriate regulatory treatment for the transaction costs associated with an investor-owned electric utility hedging its fuel transactions?

FPC's Response to Increase in Natural Gas Prices

With inputs such as relative fuel prices, unit availability, and load curves, FPC simulates its system dispatch during a given time period. As part of the output from this simulation, FPC projects the price ($/MMBtu), generation (MWH), and efficiency (Btu/kwh) by fuel type for its system during the given time period. FPC uses this output to calculate, in part, its factors for the next calendar year. Also, FPC provides similar data on a monthly basis on how its system actually operated. The table on the next page indicates FPC's estimated, actual, and the difference between actual and estimated fuel cost of system net generation, price per MMBtu, and generation by fuel type for the period November 2000 through March 2001.

Comparison of FPC's Estimated, Actual, and Difference between Actual and Estimated Fuel Cost of System Net Generation, Price per MMBtu, and Generation by Fuel Type: November 2000 - March 2001				
		Fuel Cost of System Net Generation ($000)	Price ($/MMBtu)	Generation (MWH)
Nuclear	Estimated	$9,289	$0.33	2,758,272
	Actual	$9,540	$0.33	2,835,925
	Difference	**$251**	**$0.00**	**77,653**
Coal	Estimated	$114,213	$1.83	6,551,090
	Actual	$109,315	$1.96	5,901,527
	Difference	**$-4,898**	**$0.13**	**-649,563**
Residual Oil	Estimated	$38,742	$3.40	1,099,154
	Actual	$81,302	$4.09	1,945,200
	Difference	**$42,560**	**$0.69**	**846,046**
Distillate Oil	Estimated	$17,648	$5.85	227,015
	Actual	$30,231	$6.64	372,748
	Difference	**$12,583**	**$0.79**	**145,733**
Natural Gas	Estimated	$53,901	$4.48	1,279,352
	Actual	$88,045	$6.27	1,619,855
	Difference	**$34,144**	**$1.79**	**340,503**

As natural gas wellhead prices rose, FPC implemented two strategies to mitigate the impact of these rising prices on its ratepayers. First, FPC partially mitigated the wellhead price increases by increasing generation at FPC's other generating units that do not burn natural gas, to the extent available capacity existed at these units. FPC's current generation assets are divided approximately equally among nuclear, coal-fired, oil-fired, and natural gas-fired generation with the remainder comprised of wholesale energy purchases. FPC did manage to increase generation of its residual oil, distillate oil, and nuclear units during this period. However, FPC decreased generation at its four coal-fired units. FPC's decrease in coal-fired generation was mainly the result of a higher than expected amount of forced outage and maintenance outage hours at these units. Staff has reviewed the utility's documentation of its unit availability for coal-fired generation during this period. Staff believes the utility has reasonably explained the greater-than-expected outage hours at its coal-fired units during this period.

Second, FPC minimized its use of natural gas by using the "fuel-switching" capabilities of several generating units to burn oil, instead of natural gas. Excluding its nuclear units, FPC estimates that over 40 percent of its generation capacity can switch between oil and natural gas.

Staff's Analysis of FPC's Response

From 1998 through 2000, FPC purchased 100 percent of its natural gas requirements at or indexed to the spot market price for natural gas. When the price of natural gas was less than $2.00 at the wellhead during March 1999, this strategy appeared prudent. However, as wellhead prices rose above $10.00 briefly during January 2001, FPC did take actions, as described above, to mitigate this price increase. However, FPC's mitigation options are limited. Although FPC may have been able to engage in financial hedging, FPC took reasonable steps to mitigate fuel price volatility. Nether FPC nor the Commission recognized the full potential for a dramatic rise in natural gas prices. Also, no party had requested that the Commission establish a program or mechanism to manage fuel volatility. Due to the circumstantial nature of this event, staff believes that FPC should not be held accountable on this occasion for not engaging in financial hedging.

The Commission has scheduled a workshop and hearing in this docket on June 17, 2002, and August 12-13, 2002, respectively on whether and how each utility should develop on a prospective basis a fuel procurement policy that protects its ratepayers from fuel price volatility.

In summary, based upon FPC's expectations of future changes in natural gas prices and regulatory treatment of its fuel procurement activities, FPC took reasonable steps to manage the risk associated with changes in natural gas prices.

ISSUE 2: Should this docket be closed?

RECOMMENDATION: No. If no person whose substantial interests are affected by the Commission's proposed agency action on Issue 1 files a protest within 21 days of the issuance of the order, the Commission's proposed agency action shall become final upon issuance of a consummating order. However, the docket shall remain open to address the remaining issues established in this docket.

STAFF ANALYSIS: If no person whose substantial interests are affected by the Commission's proposed agency action on Issue 1 files a protest within 21 days of the issuance of the order, the Commission's proposed agency action shall become final upon issuance of a consummating order. However, the docket shall remain open to address the remaining issues established in this docket.