CONFIDENTIAL DECLASSIFIED

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

050001-EI

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	)	Docket No. 030001-EI
	)	Filed: October 2, 2003

CONFIDENTIAL

DIRECT TESTIMONY

OF

MICHAEL J. MAJOROS, JR.

On Behalf of the Citizens of the State of Florida

5-10-05

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CONFIDENTIAL DIRECT TESTIMONY

OF

MICHAEL J MAJOROS, JR.

DOCKET NO 030001-EI

INTRODUCTION

Q. Please state your name.

A. My name is Michael J. Majoros, Jr.

Q. By whom and in what capacity are you employed?

A. I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"), an economic consulting firm with offices at 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. Have you attached a summary of qualifications and experience?

A. Yes. Appendix A is a brief description of my qualifications and experience. It also contains a listing of my appearances before state and Federal regulatory bodies.

Q. At whose request are you appearing?

A. I am appearing at the request of Florida Office of Public Counsel ("OPC")

BACKGROUND OF CASE

Q. Please explain your understanding of the background in this case.

A. On February 24, 2003 Tampa Electric filed a petition before the Florida Public Service Commission requesting approval of its proposed modifications to its fuel and purchased power cost recovery factors. The Company claimed it faced an under-recovery of $60.6 million over the remainder of 2003. The projected under-recovery is due to several factors, including increased commodity costs in natural gas and oil, leading to increased purchased power costs and unusually cold weather. The

Company's projections reflect the shutdown of Gannon Units 1 and 2 and the tie-in of the repowered Bayside 1 unit.

The PSC did not accept the Company's request in its entirety. It allowed a portion of the costs to be recovered, but deferred recovery of $26.0 million in replacement power costs associated with the early shutdown of Gannon Units 1-4, until the Commission could determine the prudence of the decision.[1]

SUBJECT OF TESTIMONY

Q. What is the subject of your testimony?

A. My testimony addresses the benefits received by Tampa Electric's stockholders as a result of the early closure of Gannon Station, while ratepayers are correspondingly charged higher rates for fuel costs in this docket. Tampa Electric has failed to recognize the benefits it will achieve through lower operating expenses that stockholder's will enjoy, while its customers are charged higher fuel costs as a result of the Company's decisions. Since the closure of Gannon station earlier than planned was an economic decision that benefited the stockholders at the expense of the ratepayers, the Citizens are requesting that Tampa Electric's fuel cost recovery be offset by $9.1 million for 2003 and $16.0 million for 2004, so that Tampa Electric's stockholders are neither better nor worse off as a result of the early closure of the Gannon plants, while ratepayers receive some offset to the higher fuel costs. Tampa Electric proposes to charge these excess replacement fuel costs to its ratepayers through its Fuel and Purchased Power recovery charges. I disagree with Tampa Electric's proposal. The incremental O&M savings of $9.1 million for 2003 and

[1] Order Approving Mid-Course Correction to Fuel and Purchased Power Cost Recovery Factors, Docket No. 030001-EI, Order No. PSC-03-0400-PCO-EI, Issued March 24, 2003, at page 9.

$16.0 million for 2004 should be offset by the Commission in the fuel clause calculations in this docket.

Q. Please describe the circumstances behind the early shutdown of Tampa Electric's Gannon plant.

A. Tampa Electric has six coal fired units at its Gannon facility. On December 6, 1999 Tampa Electric entered into a Consent Final Judgment ("CFJ") with the Florida Department of Environmental Protection, and on February 29, 2000, a Consent Decree ("CD") with the United States Environmental Protection Agency, regarding Gannon Station. Under the CFJ and CD Tampa Electric agreed to cease coal-fired operations at Gannon by December 31, 2004. Additionally, the CD required Tampa Electric to repower coal-fired generating capacity at Gannon of no less than 200 MW by May 1, 2003.[2]

As part of its 2002 Ten Year Site Plan, Tampa Electric stated that it would operate Gannon 1-4 until the December 31, 2004 deadline and would repower Gannon 5 and 6 by May 2003 and May 2004 respectively.[3] The 2002 Tampa Electric budget process contemplated closure of Gannon's coal units in September, 2004, in compliance with the CFJ and CD agreements (Exhibit No. MJM-1). On February 6, 2003 the Company announced its decision to shut down the Gannon plant early. Tampa Electric anticipated that Gannon Units 1 and 2 would cease operations in mid-March 2003, and Gannon Units 3 and 4 would cease operations by October, 2003.[4]

Tampa Electric expected to lose 867,000 MWHs of coal-fired generation as a result of the early shutdown of Units 1-4. It also projected to spend $52/MWH to replace the lost generation. According to the Commission, the average fuel cost for

[2] Direct Testimony of William Whale ("Whale"), page 3.
[3] Order Approving Mid-Course Correction to Fuel and Purchased Power Cost Recovery Factors, Docket No. 030001-EI, Order No. PSC-03-0400-PCO-EI, Issued March 24, 2003, at page 6.
[4] Id.

coal-fired generation is approximately \$22/MWH or \$30/MWH less than Tampa Electric's estimated replacement power cost. Hence, staff estimated the incremental replacement power cost to be \$26 million, i.e., 867,000 x \$30. That is the amount of money that Tampa Electric proposed to pass-through to the ratepayers in its filing with the Florida PSC on February 24, 2003.

Q. What is the current status of the Gannon units?

A. Units 1 and 2 were actually shut down on April 7 and 8, 2003.[5] In May 2003 Gannon 1 and 2 were returned to service due to weather and other circumstances. They operated for several days and then were returned to long-term standby. According to Tampa Electric witness William Whale, Units 3 and 4 will be shut down around October 15, 2003, allowing Bayside Unit 2 to utilize the transmission facilities currently used by Gannon Unit 4.[6] Unit 5 was shut down on January 30, 2003 to allow conversion of its steam turbine generator to the Bayside Unit 1 combined cycle configuration.[7] According to the Company's website, Bayside Unit 1 went into commercial service in May 2003. Unit 6 is expected to shut down around September 30, 2003, in preparation for conversion to Bayside Unit 2. Although the website lists Bayside Unit 2 as scheduled for commercial service in May 2004, Mr. Whale's testimony gives a planned in-service date of January 15, 2004.[8]

<u>CORPORATE DECISION TO SHUT DOWN GANNON STATION EARLY</u>

Q. Did Tampa Electric make a corporate decision to shut down Gannon Units 1-4 early?

A. Yes. As discussed above, the Company was not obligated to shut these units down before December 31, 2004. In fact, the original plan appeared to be to run the units

[5] May 13, 2003 deposition of Buddy Maye, page 12.
[6] Whale, pages 3 and 4.
[7] Id., page 3.
[8] Id.

until sometime in September 2004, which would allow several months in which to accomplish the shutdown.

For example, Exhibit No. MJM-1 is an email from Bill Whale to Karen Sheffield, dated May 20, 2002. In this email Mr. Whale indicates that for the 2003/2004/2005/2006 budgets that are being asked for, Ms. Sheffield should assume that Gannon 1 through 4 will continue coal operation until September 30, 2004.

In another example, at page 17 of the May 13, 2003 deposition of Joann Wehle, Benjamin Smith and William Smotherman, Mr. Smotherman states "Prior to the mid-course correction our plan was to attempt to run the [Gannon] units through –through the summer of '04."[9]

Finally, Exhibit No. MJM-2, entitled "Tampa Electric Company Gannon Early Shutdown Issues Paper", states "Given the additions of Bayside 1 in May 2003 and Bayside 2 in December 2003, Tampa Electric does not need to run Gannon Units 1-4 through September 2004 as originally planned."

Q. **When does the Company claim they made the decision to shut down the units early?**

A. The Company claims that it "refined" the shutdown dates in late January and early February of 2003.[10]

Q. **When do you believe Tampa Electric decided to shut down Units 1-4 early?**

A. I believe that Tampa Electric made a corporate decision as early as October 2002 to shut down these units in 2003.

Q. **Why do you believe that Tampa Electric made this decision in October 2002?**

A. According to Bill Whale, the Company began planning an early shutdown in the fall of 2002. (Whale TR, p. 50). Bates page 3653, labeled "Key Strategies for 2003 –

[9] May 13, 2003 deposition of William Smotherman, page 17.
[10] Whale, page 8.

Gannon" is dated October 3, 2002. This document shows the Company's "base case" as assuming Gannon Units 1 and 2 would shut down on March 15, 2003, Units 3 and 4 would run until September 1, 2003 (or until the O&M dollars were gone), Unit 5 would shut down in February 2003 and Unit 6 in September 2003.

Although some of these dates have slipped, this is essentially the "early shut-down" time frame. This document demonstrates that as early as October 2002 the Company had made the decision that it would shut down its Gannon units earlier than called for in the Consent Decree. The finalized version of the Gannon Station Business Plan was completed in October 2002 and published with minor revisions on November 15, 2002. The October 2002 and November 15, 2002 versions of the business plan are based on the Company plan that was adopted in late September/early October 2002 for the early shut down of Gannon. This document is contained in the testimony of Public Counsel witness Zaetz (Exhibit No. WMZ-1).

Q. What was the basis of Tampa Electric's decision?

A. According to Mr. Whale:

> By late 2002, it became apparent that the units needed to be shut down in 2003. This realization was driven primarily by four factors: the declining availability and reliability of the units; the significant expenditures that would need to be incurred in an effort to keep the units running reliably; the potential for safety incidents; and, the short window of time until the units would be required to shut down under the CFJ and CD, regardless of how much the company might invest in an effort to keep them operating.[11]

Q. Of the reasons given for the early shut down, which do you feel was truly driving the decision?

A. I believe this was an economic decision. The Company shut the plants down in an effort to meet internal earnings goals.

[11] Whale, page 11.

Q. What is the basis of your conclusion that Tampa Electric decided to shut down Units 1-4 early to meet its internal earnings goals?

A. One only needs to read Mr. Whale's August 26, 2002 presentation to the corporate officers to understand how the Company plans to shut down Gannon in September 2004 were advanced to 2003. In this presentation to the Tampa Electric senior management Mr. Whale clearly articulates the economic advantages of the early shutdown of Gannon (Exhibit No. MJM-3). The Company would achieve substantial capital and O&M expense savings which would accrue to shareholders, and yet would pass the acknowledged higher purchased power costs through to ratepayers. As the Gannon plan evolved in 2003, all four units were required to run several weeks longer than originally planned. In the same presentation Mr. Whale laid out the adverse consequences that would directly impact customers, including the higher costs of purchased power (Exhibit No. MJM-3, page 20).

Q. How did Tampa Electric plan to meet its budget?

A. The presentation by Mr. Whale to the officers on August 26 included the specific wording (Exhibit No. MJM-3, page 15):

"Reductions to Achieve 2003 & 2004 Plug"

"Gannon – Accelerated Shutdown".

Through our depositions with Tampa Electric personnel, including Mr. Whale, we have determined that the phrase "Plug" means a budget reduction target.

Q. Were there other indicators that the decision was for economic purposes?

A. At a meeting of all the Tampa Electric officers on September 9, 2002, there was a discussion regarding business plans, described by Tampa Electric Vice President Phil Barringer in his deposition (P 20, L12-16) as "a business planning meeting, so we go through a process during the summer and fall of creating the business plan and going through budgets." The agenda includes a wide variety of cost-cutting measures under consideration (Exhibit No. MJM-4, pages 1-2). Among the items included for discussion by Mr. Whale was "Operations: Implement items presented to achieve O&M of $102,142. Evaluate moving Gannon 3 & 4 closing up to May '03." Included in the agenda notes were five scenarios for the early closure of Gannon (Exhibit No. MJM-5).

Q. Mr. Whale states that significant expenditures would need to be incurred to keep the units running reliably. Does he discuss these expenditures?

A. Yes. On page 16 of his testimony he states: "Given the current condition of these units, Tampa Electric estimates that it would need to incur additional O&M expense of approximately $57 million to try to keep Gannon Units 1 through 4 operating somewhat reliably beyond the actual and currently planned shutdown dates and through 2004."

Q. What do you believe is the source of this estimate?

A. Exhibit No. MJM-6 is an estimate of the Total Project Costs needed to operate the Gannon units through 2004. The document was prepared March 3, 2003 for Bill Whale. It shows a cost of $53.94 million to run the plants through 2004 at 80% to 85% availability. This estimate was prepared by Buddy Maye, at the request of Bill Whale.[12] I believe this is similar to the source of Mr. Whale's figure in his testimony.

Q. Is this a useful and fair estimate of the costs necessary to run the Gannon units through 2004?

A. No. In his deposition, Mr. Maye was asked about the feasibility of running Gannon 1-4 at 80 to 85 percent availability (Exhibit No. MJM-6). He stated that it was not

[12] Maye deposition, page 80.

very realistic. The same analysis shown on page 3 reflects 60% availability. It shows a total cost of $36.94 million to run Gannon 1-4 through December 2004. Mr. Maye admitted that this is a more realistic scenario and the 60 percent availability more closely reflects the typical availability of the Gannon units.[13] This is discussed further in the testimony of my colleague, Mr. William Zaetz.

Q. What do you conclude?

A. The Company claims in part that it shut Gannon 1-4 down early because the costs to keep the units running reliably through 2004 would be $57 million. This is misleading assumption. To keep Gannon 1-4 running at the availability level they normally operate would cost far less.

<u>RESULT OF EARLY SHUT-DOWN DECISION</u>

Q. What is the result of Tampa Electric's decision to shutdown Units 1-4 early?

A. There was an early estimate of $26 million in February 2003. Based on the most recent response from Tampa Electric, it would appear that the combined costs of the more expensive fuel to run Bayside, plus additional purchased power costs to replace Gannon capacity is $116.4 million (Exhibit No. MJM-7).

<u>SAFETY AND RELIABILITY</u>

Q. You mentioned earlier that Tampa Electric cited safety and reliability concerns as the reasons for the early shut down. Do you believe Gannon was unsafe?

A. No, I do not believe Gannon was unsafe. The Company has not provided any evidence demonstrating this. Mr. Zaetz addresses the Company's safety claim in his testimony.

Q. Have you found any evidence that Gannon was unreliable?

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[13] Id., pages 80-81.

A. Not necessarily. While it is true that Gannon was an aging plant, it still appeared to be meeting its performance goals. Any reliability issues can be traced to decisions made by the Company regarding maintenance issues. Mr. Zaetz addresses reliability and maintenance in his testimony.

BENEFITS TO COMPANY

Q. Did the Company believe that the early closure of Gannon Station would result in a reduction of O&M expenses?

A. Yes. In his August 26, 2002 presentation to the company officers that I discussed earlier, Mr. Whale included a slide indicating that the Company expected to achieve savings by accelerating the shutdown of Gannon Station. The 2003 savings are reported as being $11.2 million and the 2004 savings are reported as being $16.0 million (Exhibit No. MJM-3, page 16). According to Mr. Whale (Whale TR, p. 26) these savings amounts refer to O&M savings.

Q. Do increased earnings benefit shareholders?

A. Yes, as a general proposition increased earnings benefit shareholders.

Q. Did the Company expect to reduce its labor force by shutting down the plants early?

A. Yes. It appears that the Company would benefit from a reduced labor force. Labor is discussed in the July 29, 2003 deposition of Ms. Karen Sheffield. Based on the discussion it appears that at least 192 jobs have been/will be eliminated from Gannon, replaced by at least 42 positions associated with Bayside. Ms. Sheffield confirms that "it takes less people to operate Bayside and perform whatever has to be done at Gannon than it does to operate the six units at Gannon."[14]

IMPACTS TO RATEPAYERS

[14] July 29, 2003 deposition of Karen Sheffield, page 53.

Q. Did the Company envision any consequences in shutting down Gannon early?

A. Yes. In Mr. Whale's August 26 presentation there is a slide with the heading "Changes & Consequences." A subheading indicates this slide details the consequences related to the accelerated shutdown of Gannon. The bullet points are as follows: Higher Purchase Power Costs; Tampa Electric Transport coal movements reduced; Wholesale Sales Impact; At Big Bend, slower Unit turnaround times from outages (Exhibit No. MJM-3, page 20).

Q. Was the Company aware that the early shutdown of Gannon would result in increased costs that would be passed on to the ratepayers?

A. Yes. I have found several instances where the Company calculates an impact to customers due to the early shut down of Gannon Station.

For instance, when asked about the "higher purchase power costs" listed in his presentation as a consequence of the accelerated Gannon shutdown, Mr. Whale indicated that he was aware that consumers would bear that increased cost (Whale TR, page 27).

Perhaps one of the more important examples of the Company's assumptions regarding savings and customer impact can be found in the Scenario Analysis (Exhibit MJM-8) dates 9/16/02. This document shows the various scenarios for the Gannon shutdown, along with estimated O&M/NRF costs. It also shows the base O&M costs and the difference (savings). Scenario 5 most closely matches actual events, calling for Gannon 1 and 2 to shut down on March 16, 2003 and Gannon 3 and 4 to shut down on September 1, 2003. It shows an O&M/NRF savings of $10.4 million from the base case for 2003.

Likewise, Exhibit MJM-5 shows, for the most part, the same scenarios and numbers as Exhibit No. MJM-8, leading one to believe that it was prepared after

Exhibit No. MJM-8.[15] However, this document also shows "Clause Impacts" from fuel and purchased power, coal contracts and dead freight, along with an average customer bill impact. For scenario 5, the fuel and purchased power clause impact is $17.6 million. The coal contracts impact is $6.6 million and the dead freight impact is $7.7 million. The total clause impact is $31.8 million. Directly below the Clause Impact section is a line showing "average customer bill impact". For scenario 5 this number is $1.8. It is unclear as to whether this means $1.8 per bill, or $1.8 million.. Regardless, it is clear that at this point the Company expected to realize approximately $10.5 million in net savings to operating income, while expecting a $31.8 million clause impact.

Q. Are you claiming the early closure of the Gannon units in and of itself harmed the ratepayers?

A. No. Our position is that the customers should see some of the benefits of these demonstrated savings rather than bearing all the related costs while stockholders realize all the benefits.

Q. Please discuss the fuel cost impacts of the decision.

A. The difference between the cost of coal, which is the fuel used by the Gannon units, and natural gas, the fuel used by the Bayside units, is substantial. At pages 57 and 58 of the deposition of Buddy Maye, he is asked about the approximate fuel costs for Bayside and Gannon. In the week the deposition was taken he stated that the cost of gas for Bayside was approximately $5.5 per MMBTU. He guessed that for Gannon, the fuel cost was in the range of $2 per MMBTU. Fuel costs for Bayside were over twice that of Gannon on a per MMBTU basis.

Q. Has the Company discussed this fuel cost difference in the recent testimony?

[15] This document includes an amount for Bayside CSA savings of ($121 million), bringing the scenario 5 net savings to $10.5 million.

A. The Company does not detail the difference. However, in her testimony Ms. Joann Wehle discusses the Company's view of the reasonableness of the replacement fuel costs. She states that "the company procures the fuel to operate all units based on their economic dispatch" and "Tampa Electric follows its Commission-reviewed fuel procurement policies and procedures." She further states "Tampa Electric's decision to shut down Gannon Units 1 through 4 in 2003 was arrived at only after careful and deliberate evaluation of many dynamic, competing and complex factors" and "therefore, costs for replacement fuel due to the shutdown of Gannon Units 1 through 4 in 2003 are reasonable and prudently incurred."

Q. Please discuss the purchased power impacts of the decision.

A. Due to the early shutdown, Tampa Electric has projected an 867 thousand MWH decrease in coal fired generation through the year 2003. According to its petition the Company is projecting to spend approximately $52 per MWH on purchased power to replace this energy. Tampa Electric is requesting recovery of the additional cost of this purchased power that is required to replace its coal-fired capacity ($22/MWH), which is already factored into the fuel clause recovery calculations.

Q. Does the Company address this issue in the September 12 testimony?

A. Yes. Mr. Benjamin Smith addresses replacement power costs related to the early shutdown of Gannon at pages 5 through 7 of his testimony. He does not, however, provide an updated amount of these costs. In fact, he indicates that it is not possible to calculate the exact amount of replacement power purchased due to the early shutdown:

> Although Tampa Electric projects its system capacity and energy needs, the company also states that because of system dynamics, it is neither feasible nor appropriate to

> isolate and then attribute costs to a single variable, such as the shutdown of the Gannon units, on an actual basis.[16]

Q. What is the amount of the surplus coal purchase contracts that is being passed on to customers due to the 2003, rather than 2004, closing of Gannon?

A. Earlier in the planning process the Company estimated that it would experience significant damages by the early closure of Gannon due to existing coal purchase contract damages. At the present time, it does not appear that the Company will request compensation for contract damages during this recovery period.

Q. What dead freight costs were incurred and included in the fuel recovery clause due to the decision to retire Gannon in 2003 rather than 2004?

A. The Company originally calculated a significant penalty that would be passed to ratepayers due to the early closure of Gannon because its contract with TECO transport (an affiliated company) required the Company to pay transport costs relating to the minimum compensation provisions of the contract. It is our understanding that the Company no longer seeks compensation for dead freight in this docket.

Q. Did the Company realize that the benefit it would enjoy through the early shutdown of Gannon Station would be far less than the increased rates customers would pay through the fuel clause?

A. Yes. The examples above clearly show that the Company was aware of this mismatch.

Q. Does the decision to close Gannon 1-4 in 2003 for economic reasons represent an unavoidable expense on the part of the Company that is the type of expenditure the Commission has authorized for recovery through the fuel clause?

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[16] Direct Testimony of Benjamin Smith, page 6.

A. The decision to close even earlier was driven by internal economics. In general, I do not believe this type of cost would ordinarily be reflected in a fuel adjustment charge.

Q. Did the Company decide to take additional depreciation in 2003 to write off its Gannon investment?

A. Yes. The Company stated in early 2003 that it would write off its remaining depreciation for Gannon in 2003, consistent with the historical FPSC depreciation practices.

Q. Wouldn't the impact of additional depreciation in 2003 offset the O&M savings?

A. It provides a phantom offset. The Company keeps the O&M cash savings. The total depreciation recovery for Gannon did not change. The Company simply accelerated its recovery of its investment and that helped the Company's cash flow. Furthermore, the Company's most recent, June 30, 2003, Form 10-Q states the following:

> At Jan. 1, 2003, the estimated accumulated cost of removal and dismantlement included in net accumulated depreciation was approximately \$442.0. At June 30, 2003, the cost of removal and dismantlement component of accumulated depreciation was approximately \$451 million.[17]

This means that Tampa Electric has collected \$451 million from its ratepayers to dismantle and remove its plant, even though it does not have any legal obligation to incur such costs. Otherwise, those amounts would have been capitalized to plant under the auspices of the Financial Accounting Standards Board's Statement of Financial Accounting Standard No. 143.

I find it very hard to imagine that Tampa Electric will actually spend \$451 million to remove or dismantle any of its plants if it is not required to do so. That

[17] Tampa Electric Company June 30, 2003 Form 10-Q, Notes to Consolidated Financial Statements, Note 1, Depreciation.

would be "bad" internal economics. And given this Company's proclivity to enhance its positive internal economics I doubt that it would unnecessarily spend the $451 million. Furthermore, under the aforementioned accounting standard, the $451 million is a liability (amount owed) to ratepayers.

CONCLUSION

Q. What action should the Commission take in this case?

A. The Commission should require that both shareholders and ratepayers share the burden of the Company's decision to accelerate the Gannon Station retirement. The Commission should use the amount of O&M savings achieved by the Company in both 2003 and 2004 to offset the higher fuel costs associated with the Bayside natural gas plant. I calculate those savings as $9.1 million for 2003 and $16.0 million for 2004 (Exhibit No. MJM-9).

Q. Why have you included calculations for the 2004 O&M savings?

A. The issues regarding the Gannon Station early retirement are one-time issues, and the same principals that will apply in the current proceeding for 2003 should also be applied on a going-forward basis through the original, planned outage date of September 2004.

Q. Does this conclude your testimony?

A. Yes, it does.

MICHAEL J. MAJORES

INDEX OF EXHIBITS

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. Mr. Majoros has appeared before Federal and state agencies. His testimony has encompassed a wide variety of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice.

Mr. Majoros has been responsible for developing the firm's consulting services on depreciation and other capital recovery issues into a major area of practice. He has also developed the firm's capabilities in the management audit area.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros performed various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company). In addition, he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.
Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

Michael J. Majoros, Jr.

Federal Regulatory Agencies

Date	Agency	Docket	Utility
1979	FERC-US 19/	RR79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities

State Regulatory Agencies

Date	Agency	Docket	Utility
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Electric Power Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.

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1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa

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1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 38/	02-MDWG-922-RTS	Midwest Energy

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2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

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PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia2/	93-1165-E-D	Potomac Edison
West Virginia2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation

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Clients

1/ New Jersey Rate Counsel/Advocate
2/ West Virginia Consumer Advocate
3/ Pennsylvania OCA
4/ Florida Office of Public Advocate
5/ Toms River Fire Commissioner's
6/ Iowa Office of Consumer Advocate
7/ D.C. People's Counsel
8/ Maryland's People's Counsel
9/ Idaho Public Service Commission
10/ Western Burglar and Fire Alarm
11/ U.S. Dept. of Defense
12/ N.M. State Corporation Comm.
13/ City of Philadelphia
14/ Resorts International
15/ Woodlake Condominium Association
16/ Illinois Attorney General
17/ Mass Coalition of Municipalities
18/ U.S. Department of Energy
19/ Arizona Electric Power Corp.
20/ Kansas Corporation Commission
21/ Public Service Comm. – Nevada
22/ SC Dept. of Consumer Affairs
23/ Georgia Public Service Comm.
24/ Delaware Public Service Comm.
25/ Conn. Ofc. Of Consumer Counsel
26/ Arizona Corp. Commission
27/ AT&T
28/ AT&T/MCI
29/ IN Office of Utility Consumer Counselor
30/ Unitel (AT&T – Canada)
31/ Public Interest Advocacy Centre
32/ U.S. General Services Administration
33/ Michigan Attorney General
34/ New Mexico Attorney General
35/ Environmental Protection Agency Enforcement Staff
36/ Kentucky Attorney General
37/ North Dakota Public Service Commission
38/ Kansas Industrial Group
39/ City of Witchita
40/ Kansas Citizens' Utility Rate Board
41/ NIPSCO Industrial Group
42/ Hawaii Division of Consumer Advocacy
43/ Nevada Bureau of Consumer Protection
44/ GCI
45/ Wisc. Citizens' Utility Rate Board
46/ Vermont Department of Public Service
47/ Oklahoma Corporation Commission
48/ National Association of Utility Consumer Advocates ("NASUCA")

EXHIBIT MJM-1
Page 1 of 1

From: Bill Whale
To: Karen Sheffield
Date: 5/20/02 10:58AM
Subject: Base Plan

Karen

For the 2003/2004/2005/2006 budgets that are being asked for use the following operating schdule as your base plan.

Gan 1 through 4 continue coal operation until Sept 30, 2004

Gan 5 will continue coal operation until Feb 7, 2003

Gan 6 will continue coal operation until August 31, 2003

Plan on building staffing, maintenance, and budget plans around this base plan. This is the same plan that has been put in the rate case.

Thanks

Bill

CC: Bill Smotherman; Charles R. Black; Charles Shelnut; Craig Cameron; Hugh Smith; John Knight; Scott A. Cannon; Tom Berry

THIS INFORMATION CLAIMED

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EXHIBIT NO. MJM-2, PAGE 1

BY

TAMPA ELECTRIC

Tampa Electric Company
Gannon Early Shutdown
Issues Paper

CONFIDENTIAL

Background

- Given the additions of Bayside 1 in May 2003 and Bayside 2 in December 2003, Tampa Electric does not need to run Gannon Units 1 – 4 through September 2004 as originally planned
- Evaluate five possible scenarios for early shutdown in 2003
  - 1-All units shutdown May 1
  - 2-All units shutdown March 16
  - 3-Units 1, 2 shutdown May 1 and Units 3, 4 shutdown September 1
  - 4-Units 1, 2 shutdown March 16 and Units 3, 4 shutdown May 1
  - 5- Units 1, 2 shutdown March 16 and Units 3, 4 shutdown September 1

Other assumptions include
  - Eliminate Big Bend 2 outage in 2003
  - Enter into purchase power agreement (7x10) @ $50/Mwh
  - Unused coal will be sold to third parties @ $4.75/ton loss and is recoverable through Fuel Clause
  - Dead freight cost is recoverable through Fuel Clause

Issues to Consider/Address

- Fuel and capacity clause increase
  - Purchased power
  - Coal contract tonnage
  - Dead freight

$23M

- Other impacts
  - Accelerated depreciation on coal-related equipment from 2004 to 2003 totals approximately $~~20~~ million
  - 2005 removal-type costs move into 2004. Include $18 million for facility and coal-yard cleanup, inventory write-off, safety, etc. Cash impact only?
  - CSA impacts for Bayside and Polk units
- Timely start up and immediate reliance on Bayside 1
- Other discovery matters

Qualitative and Quantitative Analysis Results

- Units should be shut down in pairs
- Units should be shut down in conjunction with Bayside unit(s) coming into service

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ENERGY SUPPLY

- What Are Our Resources, Where Do They Go?
- Operational Strategies
- Changes and Consequences

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EXHIBIT MJM-3
Page 1 of 34

What Are Our Resources?

(2002 Budget) ($ millions)	O&M	NRF	Total Resources
Operations	$ 127.1	$ 13.9	$ 141.0
Trading & Services	8.3	-	8.3
Construction & Engineering	2.9	-	2.9
	$ 138.3	$ 13.9	$ 152.2

EXHIBIT MJM-3
Page 2 of 34

Where Do They Go?

- Station / Services
- Type (Labor, Services, Materials & Supplies, etc.)
- Activity (Operations Maintenance, Compliance, Services)

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Resources - Stations

(2002 Budget) ($ million)	BIG BEND	GANNON / HOOKERS	POLK	SEBRING
O&M	$ 62.1	$ 37.4	$ 19.3	$ 1.3
NRF	5.0	4.4	4.3	.2
TOTAL	$ 67.1	$ 41.8	$ 23.6	$ 1.5

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EXHIBIT MJM-3
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Resources - Services

	Support Services	Shared Services
O&M	$ 13.1	$ 5.1

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Resources - Type

(O&M and NRF)

Energy Supply	Millions	Percentage
Payroll/Fringe	66.4	44%
Contractors/Services	44.7	29%
Materials / Supplies / Stores Issues	31.2	20%
Vehicles / Other Mobile Equipment	2.7	2%
Shared Service Allocation	5.1	3%
All Other	2.1	2%
Total	**$ 152.2**	**100%**

EXHIBIT MJM-3
Page 6 of 34

Resources - Activity

(O&M and NRF)

Administration			
Support Services	13.1		
Shared Services	5.1	18.2	12%
Plant Operations			
Labor / Fringe	19.9		
Consumables	3.8		
Non-recoverable Fuel	13.9		
Other	7.7	45.3	30%
Plant Maintenance			
Unit Specific	26.9		
CSAs	2.2		
Common	41.9	71.0	47%
FGD			
Operations	10.9		
Maintenance	6.8	17.7	11%
Total Activities		152.2	100%

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EXHIBIT MJM-3
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Plant Operations

- Labor
  - Driver = Equipment / Safety
  - Cost Reduction Strategies
    - Contractor Usage
    - Shifts
    - Technology
- Consumables / NRF
  - Driver = Equipment Operations
  - Cost Reduction Strategies / Cost Increases
    - Efficiencies
    - Increase Performance Expectations
    - New Requirements

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Plant Maintenance

- Forced Outages
- Planned Outages
  - Fuel Systems
  - Major Outages
- Routine Maintenance

EXHIBIT MJM-3
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Forced Outages

- Best Guess Estimate
  - $25,000 / Day - Gannon
  - $35,000 / Day - Big Bend
- Cost Reduction Strategies
  - Contractor Usage
  - No Overtime
  - Operational Strategies
  - Rule of Thumb
    - 1% Increase in EFOR ~ 3% Increase in Cost

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EXHIBIT MJM-3
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Planned Outages

Fuel System Outages	vs	Major Outages
Performed Annually		Performed once every 4 yrs.
Duration of 14-21 Days		Duration of 50-70 Days
Clean-Up		Clean-Up
Inspection		Inspection
Minor Repairs / Patches		Major Repairs
O&M Intensive		Major Component Replacement
		O&M and Capital Intensive

EXHIBIT MJM-3
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Planned Outages

- Cost Guidelines
  - $45,000 / Day - Fuel Systems
  - $60,000 / Day - Major
- Cost Reduction Strategies
  - Increase Contractor Usage
  - Limit Overtime
    - No Outage Overlap
    - Time Between Majors
  - Component Replacement Timing

EXHIBIT MJM-3
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Forecasted Outages

		2002	2003	2004	2005	2006	2007
Big Bend	Fuel	2	3	4	2	2	3
	Major	2	0	0	2	1	1
Polk	Fuel	1	1	2	2	2	1
	Major	0	1	0	1	1	0

EXHIBIT MJM-3
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Routine Maintenance

- Priority
  - Safety
  - Compliance with Law
  - Efficiency
  - Reliability Centered Maintenance
- Cost Reduction Strategies
  - Increased Contractor Usage
  - Run to Failure
  - Minimal Replacement Parts

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EXHIBIT MJM-3
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Operating Capital (millions)

	Big Bend	Gannon/ Hookers	Bayside	Polk	Sebring
Installed MW	1,934MW	1,165MW	1,750MW	615MW	18MW
2002 Fcst	$37.3	$4.3	$0.0	$18.9	$0.7
2003 Plug	18.1	2.3	7.2	12.0	0.2
2004 Plug	17.1	0.0	17.1	10.6	0.3

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Changes & Consequences

Reductions to Achieve 2003 & 2004 Plug

Gannon - Accelerated Shutdown

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Changes & Consequences

Gannon - Accelerated Shutdown (Implementation)

- Units 1 & 2 - Shutdown with Bayside 1 Start-up
- Units 3 & 4 - Shutdown September 1, 2003.

  (Anticipates depletion of available funding)

551

- 2003 Savings $ 11.2 million
- 2004 Savings $ 16.0 million
- Big Bend to reduce Contractors, Overtime, Unit Header Pressures. 2003 Savings $ 2.0 million.

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Station Performance

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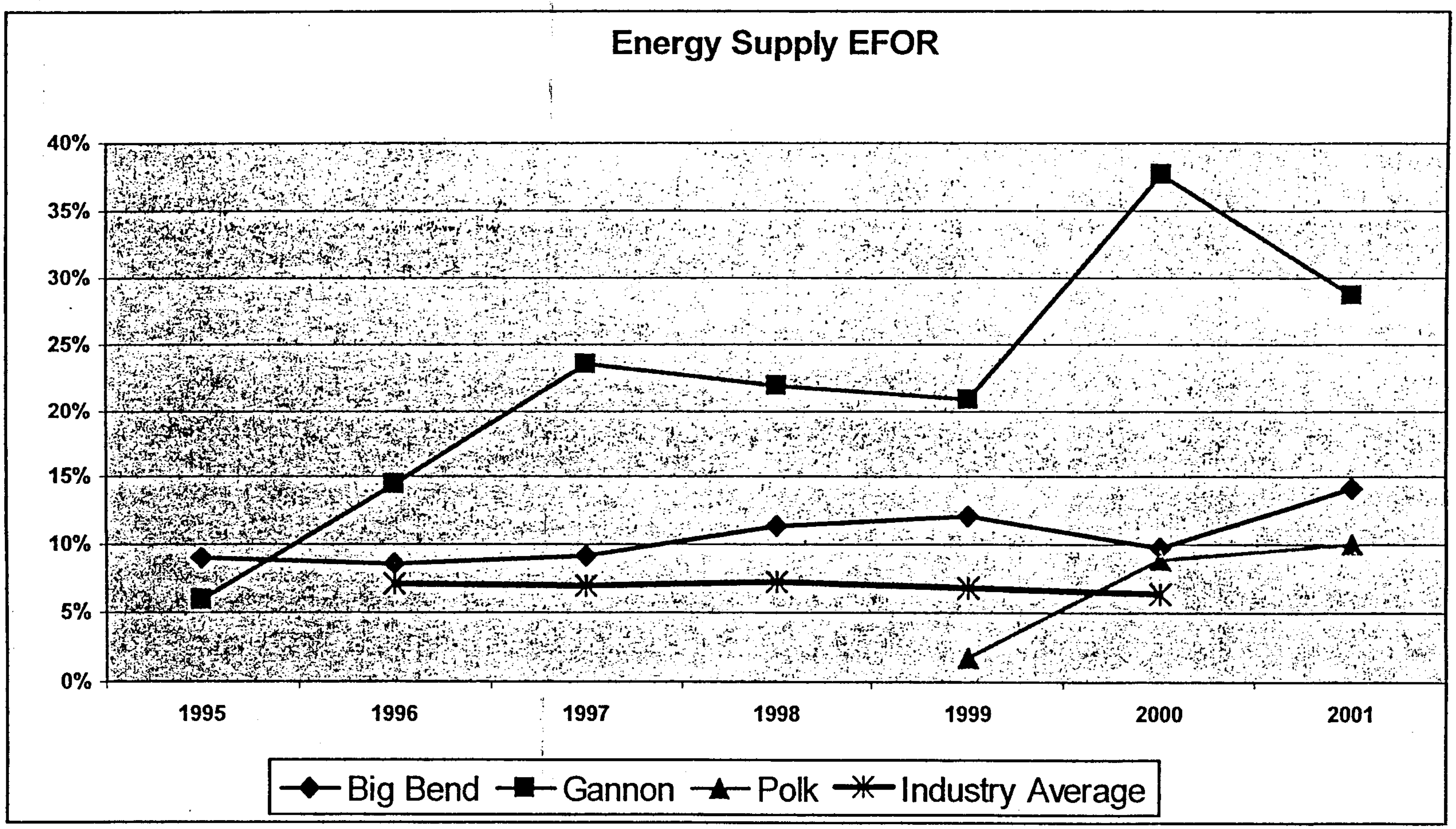

Station Performance

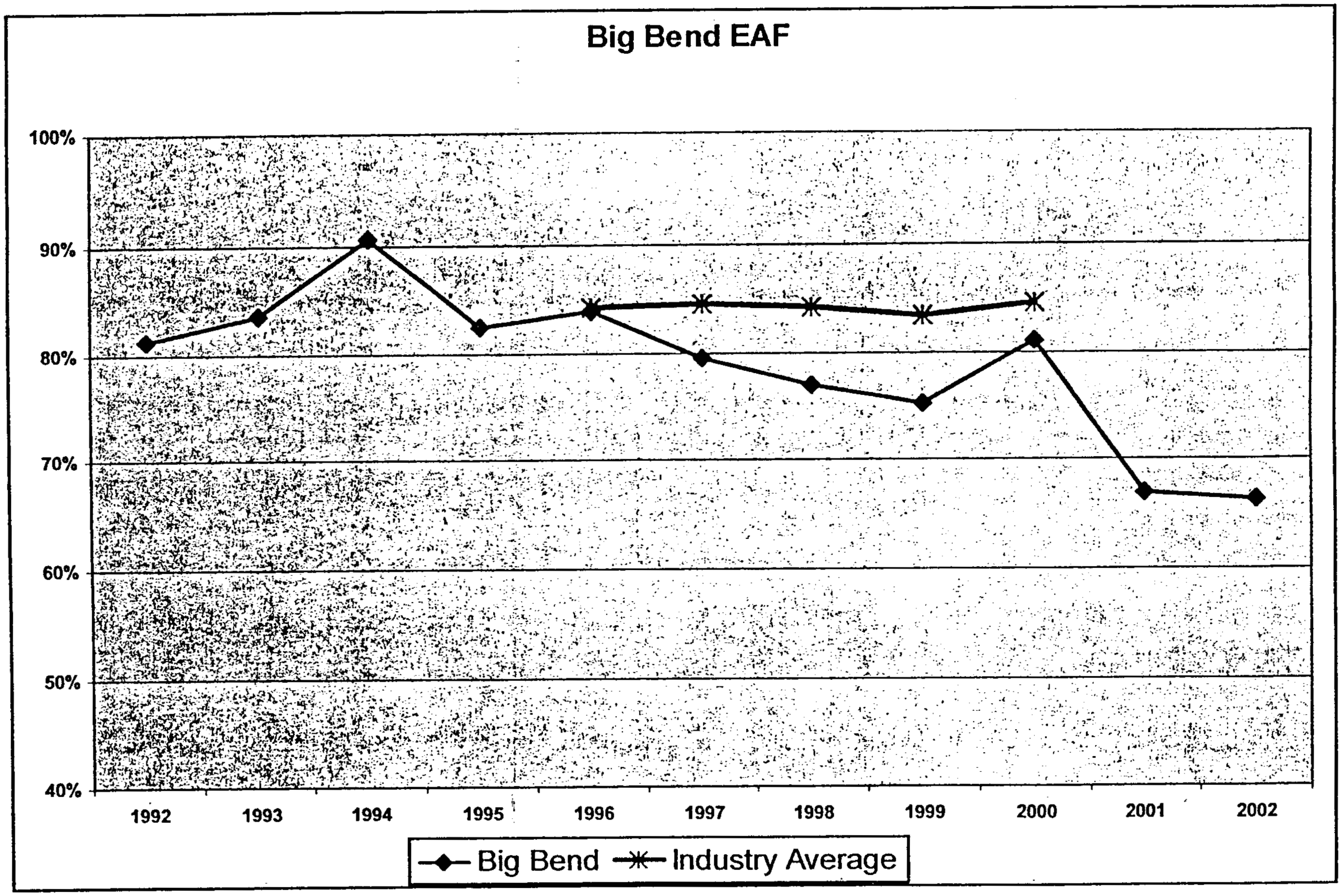

EXHIBIT MJM-3
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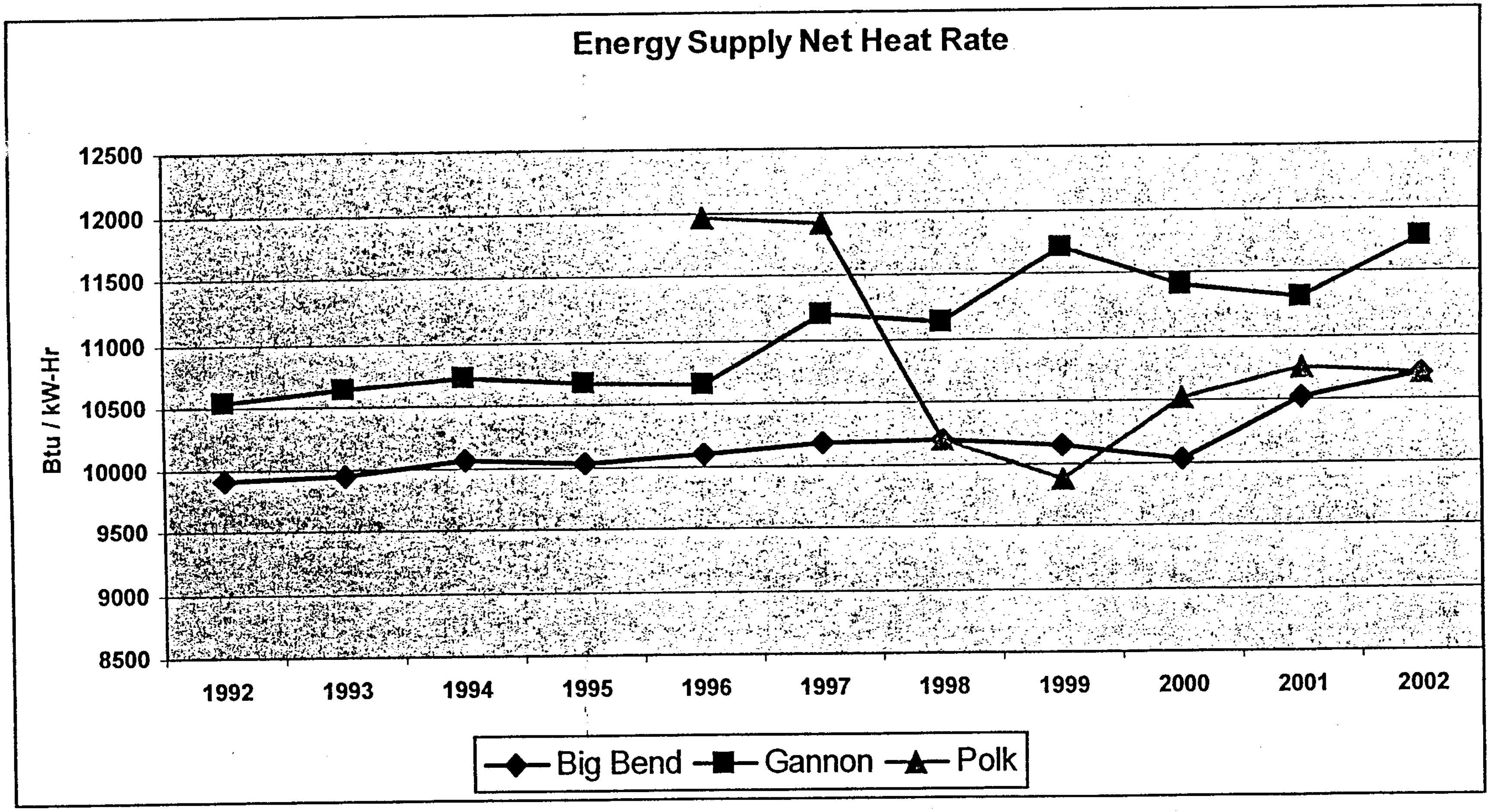
Station Performance



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Changes & Consequences

Gannon - Accelerated Shutdown (Consequences)

- Higher Purchase Power Costs
- TECO Transport coal movements reduced
- Wholesale Sales Impact
- At Big Bend, slower Unit turnaround times from outages.

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EXHIBIT MJM-3
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Resources - Stations

	BIG BEND	GANNON	POLK	SEBRING
Installed Capacity (Summer Rating)	1934	1165	615	36
Number of Units	4 Coal Fired 3 CTs	6 Coal Fired	1 Combined Cycle 2 CTs	2 Diesel Engines
Fuel Type	Coal	Coal	CC-Synfuel CTs - Gas / Oil	Diesel
Constructed	1969	1957	1995	1982
Average Unit Age	27	40	3	20
Major Support Sys.	2 FGD Systems		Gasifier Air Separation Unit Acid Plant	
Operating Profile	Baseload	Baseload	Baseload / Peaking	Peaking
Operating Strategy	Sustain L-T Reliability	Patch and Go/ Run to Failure	Unit 1 - Baseload Unit 2/3 - Peaking	Peaking

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Resources - Services

ENIRONMENTAL

Permitting
Monitoring
Communities
Legal / Compliance
Land & Water Projects

FUELS

By Products Management

RESOURCE PLANNING

System Planning

WHOLESALE MARKETING

Wholesale Energy Purchase/Sales

AUDIT MANAGEMENT

Administration
Finance
Human Resources
Safety
Technical Administration

ENGINEERING & CONSTRUCTION

Engineering
Project Management
Construction

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EXHIBIT MJM-3
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Life Cycles & Outage Strategies

OPERATING STRATEGIES

• Big Bend	Baseload	10 year horizon SCR / Consent Decree FGD / Interlock
• Gannon	Intermediate	Patch & Go Run to Failure

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EXHIBIT MJM-3
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Life Cycles & Outage Strategies
(Continued)

OPERATING STRATEGIES

• Polk	Unit 1	Baseload
		Demonstrate Gasifier
		Low Cost Fuel Dispatch
	Unit 2 & 3	Peaking
• Sebring		Peaking

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EXHIBIT MJM-3
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What Are Our Resources?

(2002 Budget) ($ millions)	O&M	NRF	Operational Capital	Total Resources
Operations	$ 127.1	$ 13.9	$ 62.3	$ 203.3
Trading & Services	8.3	-	6.1	14.4
Construction & Engineering	2.9	-	-	2.9
	$ 138.3	$ 13.9	$ 68.4	$ 220.6

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Resources - Stations

(2002 Budget) ($ million)	BIG BEND	GANNON / HOOKERS	POLK	SEBRING
O&M	$ 62.1	$ 37.4	$ 19.3	$ 1.3
NRF	5.0	4.4	4.3	.2
Operational Capital	37.3	4.3	18.9	.7
	$ 104.4	$ 46.1	$ 42.5	$ 2.2

EXHIBIT MJM-3
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Resources - Type

Energy Supply	Millions	Percentage
Payroll/Fringe	69.9	32%
Contractors/Services	86.8	39%
Materials / Supplies / Stores Issues	53.9	25%
Vehicles / Other Mobile Equipment	2.7	1%
Shared Service Allocation	5.1	2%
All Other	2.2	1%
Total	**$ 220.6**	**100%**

562

Resources - Activity

Administration		
Support Services	14.2	
Shared Services	5.1	19.3
Plant Operations		
Labor / Fringe	19.9	
Consumables	3.8	
Non-recoverable Fuel	13.9	
Other	7.7	45.3
Plant Maintenance		
Unit Specific	54.5	
CSAs	15.6	
Common	53.3	123.4
FGD		
Operations	10.9	
Maintenance	15.6	26.5
Environmental Projects		6.1
Total Activities		220.6

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Significant Capital Projects

Capital Budgeting Schedule - 2003

Project Title	Budget ($ Thousands)
BB Lined Solid Waste management unit	$ 4,000
Repair/Replace BB4 economizer ash liner	3,273
GE Combustion Turbine LSTA Agreements (unit 1)	2,543
GE Combustion Turbine LSTA Agreements (unit 2)	2,418
Close out DA2 Cell B	2,000
BB Dissolved Oxygen Environmental issues	2,000
BB Lined recycle pond	2,000
BB Gypsum conveyor relocation	2,000
FGD (3&4) REPL COMMON INLET DUCT RE	1,952
GE Combustion Turbine LSTA Agreements (unit 3)	1,841
POLK Cooling reservoir water	1,700
BB4 BOILER FURNACE FLOOR/SLOPE REPL	1,616
Water cannons or wall blowers BB3	1,134
BB Lined stormwater collection pond	1,000
BB Big Bend pipe replacements	1,000
BB1 Under Deck Fire protection Units (1-4)	1,000

EXHIBIT MJM-3
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Significant Capital Projects

Capital Budgeting Schedule - 2004

Project Title	Budget ($ Thousands)
Polk Cooling reservoir water quality study	$ 4,000
BB Lined Slag Sluice and settling ponds	4,000
BB lined recycle pond	4,000
BB Gypsum storage dome	3,000
GE Combustion Turbine LSTA Agreements (unit 1)	2,881
Polk Lined Landfill	2,713
SOFA BB4	1,900
GE Combustion Turbine CSA Agreements (unit 2)	1,725
GE Combustion Turbine CSA Agreements (unit 3)	1,712
BB WASTE MANAGE/LINING RECYLE POND	1,000
BB Lined stormwater collection pond	1,000

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EXHIBIT MJM-3
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Operational Strategies

Maintenance

- Outages - Fuel System / Major
- Forced Outages - Return to Service ASAP without compromising safety or environmental compliance using Contractors.

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Labor

- Hold the workforce to a minimal level, sustaining operations and keeping a preventative maintenance workforce. Use Contracted labor to handle increased workload (outages) and unique specialized services.

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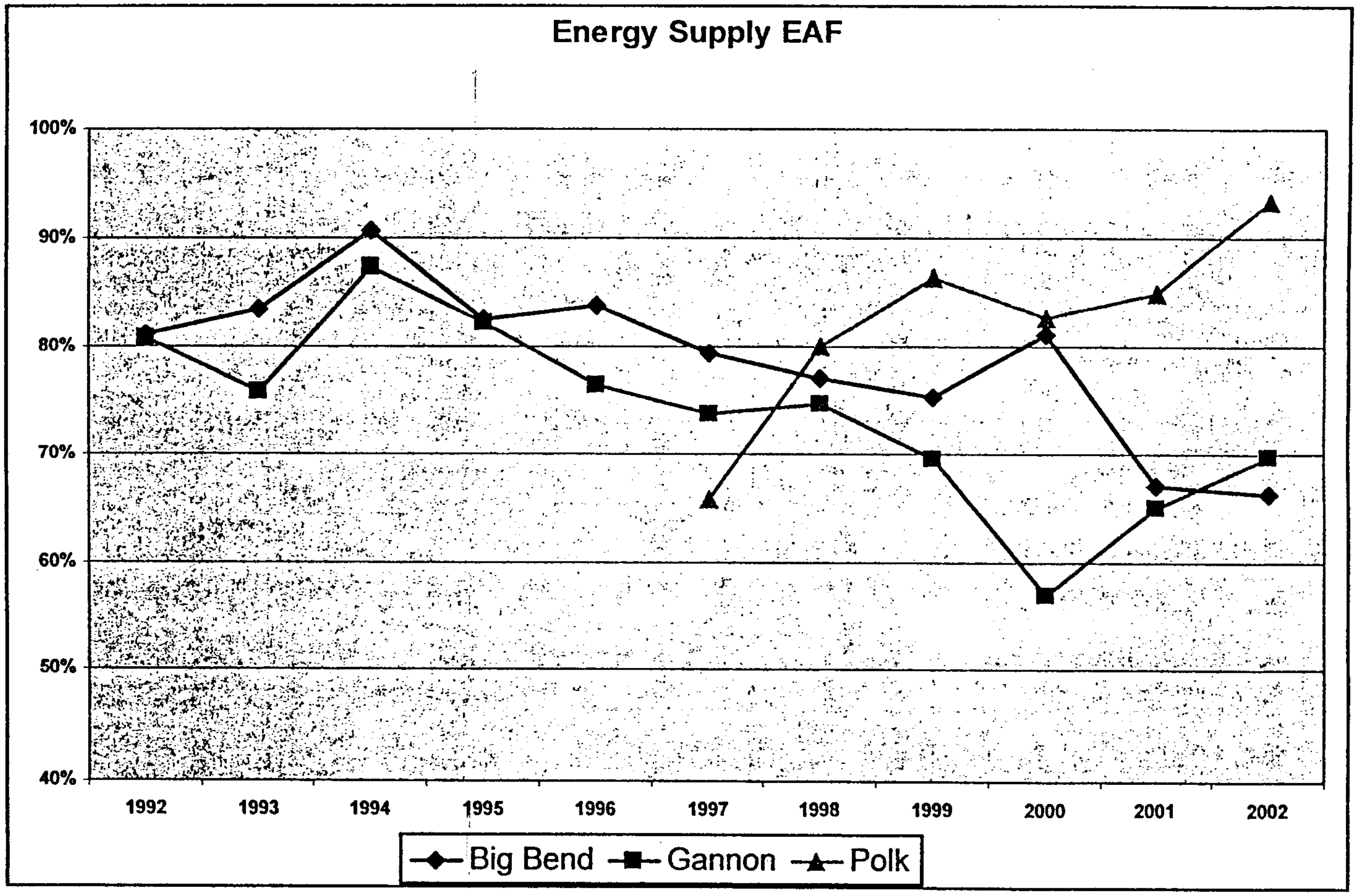
Station Performance



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Labor Strategy

- **In-house Labor**
  - Operations
  - Preventative / Operational Maintenance Activities
  - Project and Cost Management Engineering
  - Management and Administration
- **Contracted Activities and Services**
  - Maintenance Activities
    - Clean-up / Grounds Maintenance "Core Contractors"
    - Forced Outage Maintenance
    - Planned Outage Maintenance
    - Specialized Activities (Painting, Insulation, Equipment Overhauls)
  - **Specialized Services**
    - Technical Services
    - Performance Engineering and Testing
    - Major Engineering

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EXHIBIT NO. MJM-4 PAGE 1 & 2

BY

TAMPA ELECTRIC

Officer Discussion 9/9/02

Salary: C/B: Officers: Ø
IBEW: 3.6%
Non-Con/Non-Exempt.

TAMPA ELECTRIC COMPANY
2003 AND BEYOND
Business Plan Discussion
Results/Action Items
August 30, 2002

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DRAFT

Overall:

All	Review spans of control, look at achieving minimum spans of 7 – 8
All	Reduce management levels where possible (Dir/Mgr/Sup. . .only two out of three)
All	Review Financial shops and staffing levels
All	Identify anything that can be leased vs bought
• All	Prepare for Zero based budget discussion – where is every dollar to be spent
• All	Reduce Salary increases from 4% to 3% and impact currently shown targets — Leave @ 3% for now

Energy Supply:

WTW	Operations: Implement items presented to achieve O&M of $102,142 (M/H early shutdown GN
WTW/HWS/DAB	Evaluate moving Gannon 3&4 closing up to May 03 — What are the savings? What are the people impacts? Reserve margin issues? Transport issues. Purchase power strategy
WTW/HWS/CRB	Identify steps to further reduce 2003 O&M by $5M and $6M in capital among the three ES organizations
Got to have HWS	Sale of Gasifier by Quarter 1 2003
Got to have CRB/HWS	Unload Turbine commitment (Siemens coming due)
HWS	Sale of any assets, even at a book loss, e.g., Hookers Point, Sebring
CRB	Optimize CSA costs, work with TPS — already bought
DAB	Look at ECRC opportunities: SCRs, HRSGs, etc. → No
DAB	Bayside PPA (financing opportunities)
PLB/HWS	Evaluate achieved warehousing efficiencies
HWS	Strategy for Transport issues
CRB	Big Bend longer term strategy
CRB/PLB	Optimal timing of Bayside II in-service

MM 1&2 to Gas

P.P.: 19-2
Coal: 6-7
Down Pct: 7-12

Net Sav: 14.6M
3/1: 5/1 16.0

O&M CRB $400k
HWS Look

NO — Scenario 5: 1.7
+4. M

ENV. Capital:
911, Security Co
→ $1.0 M

Energy Delivery:

TLH	Implement items to achieve O&M of $45,434 and Capital of $93,681 — 125 folks N/C, 13 reassign
	-Finalize new lighting strategy —
TLH/DAB/ASA	Transmission sale — Calpine 15 — Gr. proceeds 1.2-2.0

Customer Services and Marketing:

ASA	Implement items presented to achieve O&M of $36,000 — Including an additional investment of $500K in the Call Center; Closure of ETRC - 2nd yr of 5 yr.
ASA/PLB	Evaluate Sale of Bad Debt, achieve timing flexibility as a contingency item
ASA/JDP	Close Winter Haven office and merge with Plant City

Technology and Support Services:

MND/KMM	Implement items to achieve $1M of O&M savings across the organization beyond currently set levels — Reduced service levels, prolonged replacement cycles, avoided maintenance agreements, etc. — ongoing
KMM/All	Eliminate $2.5M in annual net PC replacements (capital)
MND/All	JBR's deal: Will give back to your budget 50 cents for every dollar you reduce with T&SS (no cost shifting allowed)
MND	Land sale opportunities: Port Manatee, PHFFU, etc., Site X (Turkey Creek?) — appraised @ 2.9 M, 500k

MND	Scrub costs (capital & O&M) to achieve lowest acceptable service levels

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Human Resources:

CEC/WWH/All	Develop overall strategy for headcount reductions, including communications
CEC	Implement items to achieve O&M of $39,000
CEC	Evaluate ESOP sensitivity to $1.00 stock price change
CEC/DAB	Evaluate 911 Security costs and clause opportunities

All other Departments:

All	Achieve or beat committed targets by reduced headcount, travel, training, etc.

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EXHIBIT NO. MJM-5 PAGE 1

BY

TAMPA ELECTRIC

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Tampa Electric Company
Gannon Early Shutdown

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Clause Impacts					
Fuel & Purchased Power	$26,549	$30,552	$15,959	$28,199	$17,605
Coal Contracts	6,882	7,238	6,347	7,086	6,555
Dead Freight	10,538	12,849	6,862	11,348	7,670
Total Clause Impact	43,969	50,639	29,168	46,633	31,830
Average customer bill impact	$2.4	$2.8	$1.6	$2.6	$1.8
Operating Income Impacts					
Gannon Base	38,400	38,400	38,400	38,400	38,400
O&M and NRF Expenses	23,000	21,000	28,500	22,000	27,500
Bayside Costs	900	1,100	500	1,000	500
Bayside CSA Savings *	-105	-101	-123	-103	-121
Net Savings	14,605	16,401	9,523	15,503	10,521

* Polk CSA costs not included

1187

From: John Knight
To: Bill Whale; Buddy Maye; Craig Cameron; Dee Brown; Denise Jordan
Date: Mon, Mar 3, 2003 4:24 PM
Subject: Gannon 1 - 4 (options)

Print each TAB. If you have any questions please call.

Energy Supply
Gannon Station - Operations Thru 2004
Achieve 80 - 85% Availability

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Other	
Cyclone work (49 day outage)	4,500	4,500	6,000	6,000		21,000
Rear wall replacement		2,300				2,300
Expansion Joints	60	60	60	60		240
Insulation and Lagging	200	200	200	200		800
Slag Tank neck			150			150
Coal Field Eqp.					250	250
Additional Requirements	4,760	7,060	6,410	6,260	250	24,740
2003 28 day outage	500	500	250	250	-	1,500
2003 staff requirements	-	-	-	-	3,200	3,200
Stevedores	-	-	-	-	400	400
Required O&M (Consumables / Other)	-	-	-	-	1,600	1,600
Additional Ops. Costs	500	500	250	250	5,200	6,700
Total Costs 2003	**5,260**	**7,560**	**6,660**	**6,510**	**5,450**	**31,440**
2004 28 day outage	500	500	500	500	-	2,000
2004 staff requirements					12,200	12,200
Stevedores	-	-	-	-	1,200	1,200
Required O&M (Consumables / Other)					7,100	7,100
Total Costs 2004	500	500	500	500	20,500	22,500
Total Project Costs	5,760	8,060	7,160	7,010	25,950	53,940

Prepared March 3, 2003

Energy Supply
Gannon Station - Operations Thru 2004
Achieve 60% Availability

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Other	
Rear wall replacement		2,300				2,300
Expansion Joints	60	60	60	60		240
Insulation and Lagging	200	200	200	200		800
Slag Tank neck			150			150
Coal Field Eqp.					250	250
Additional Requirements	260	2,560	410	260	250	3,740
2003 28 day outage	500	500	250	250	-	1,500
Forced outage costs (Cyclone driven)	500	500	500	500	-	2,000
2003 staff requirements	-	-	-	-	3,200	3,200
Stevedores	-	-	-	-	400	400
Required O&M (Consumables / Other)	-	-	-	-	1,600	1,600
Additional Ops. Costs	1,000	1,000	750	750	5,200	8,700
Total Costs 2003	**1,260**	**3,560**	**1,160**	**1,010**	**5,450**	**12,440**
2004 28 day outage	500	500	500	500	-	2,000
Forced outage costs (Cyclone driven)	500	500	500	500	-	2,000
2004 staff requirements					12,200	12,200
Stevedores	-	-	-	-	1,200	1,200
Required O&M (Consumables / Other)					7,100	7,100
Total Costs 2004	**1,000**	**1,000**	**1,000**	**1,000**	**20,500**	**24,500**
Total Project Costs	**2,260**	**4,560**	**2,160**	**2,010**	**25,950**	**36,940**

Prepared March 3, 2003

Tampa Electric Company

Calculation of Incremental Fuel and Purchased Power Costs
Related to the Early Shutdown of Gannon Units 1 Through 4

Line No.	2003 Total Fuel & Net Power Transactions	Amount
1	Per Denise Jordan, August 12, 2003 Schedule E2, Line 9 Assumes shutdown of Gannon 1 & 2 and tie-in of repowered Bayside 1	$ 680,265,173
2	Per Response to OPC Interrogatory, 3rd Set, Qustion No. 46. Assumes Gannon Units 1-4 run through December 31, 2003	$ 563,897,100
3	Difference Due To Early Shutdown Line 1 - Line 2	$ 116,368,073

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 030001-EI FILED: AUGUST 25, 2003

TAMPA ELECTRIC COMPANY'S

ANSWERS TO THIRD SET OF INTERROGATORIES (NO. 46)

OF

THE OFFICE OF PUBLIC COUNSEL

Tampa Electric files this its Answers to Interrogatories (No. 46) propounded and served on July 21, 2003, by the Office of Public Counsel.

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
INDEX TO OPC'S 3RD SET OF INTERROGATORIES (NO. 46)

Number	Witness	Subject	Page
46	William A. Smotherman	Total fuel costs and net power transaction costs using September 2002 assumptions if Gannon units were available through 2003	1

William A. Smotherman
Director, Resource Planning
Tampa Electric Company
702 N. Franklin Street
Tampa, FL 33602

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
OPC'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 46
PAGE 1 OF 2
FILED: AUGUST 25, 2003

46. Calculate the total fuel costs and net power transaction costs as if Gannon Units 1 - 4 were still dispatchable on Tampa Electric's system through year end 2003, using the same assumptions contained in Denise Jordan's testimony filed in September of 2002.

A. Tampa Electric prefaces its answer to this interrogatory with the observation that a number of significant factors negate the substantive value and usefulness of the results of the calculation requested in this interrogatory. The assumption that Gannon Units 1 - 4 could remain dispatchable on Tampa Electric's system through the end of 2003 is hypothetical and is premised on the highly doubtful assumption that these units could be safely and reliably operated on a dispatchable basis over the time frame in question. Before selecting its current shutdown schedule for Gannon Units 1 - 4, Tampa Electric's management carefully considered many factors including those relating to safety, reliability, employee utilization, the ages and condition of the units and the significant amount of delay and expense the company would risk in an effort to keep them operational for only a short period of time given the requirements of the Consent Decree and the Consent Final Judgment to shut down or repower all coal-fired generation units at Gannon Station by the end of 2004. Any hypothetical dispatchability of Gannon Units 1 - 4 beyond the current shutdown schedule would erroneously and without justification simply dismiss all of these factors as being irrelevant.

In addition, Interrogatory No. 46 asks Tampa Electric to perform the present day cost calculation using old assumptions that were fresh at one time but which are stale now and which do not reflect the current outlook or the intervening events which have shaped the current outlook. Tampa Electric properly updated all assumptions that had changed between the time it filed 2003 projections in September 2002 and its February 2003 revised mid-course correction filing, including the Gannon Units 1 - 4 shutdown dates. Applying historical assumptions in a cost calculation performed later in time invalidates the results of the calculation. Modeling tools such as those the company uses to estimate projected net fuel and power transactions are aids for considering potential impacts, but they do not reflect actual results. Therefore, conclusions drawn based on the hypothetical value requested here are likely to be incorrect.

Subject to these qualifications, Tampa Electric has estimated its system net fuel and power transaction amounts as requested, using the September 2002 filing assumptions, with the exception that the Gannon shutdown dates reflect the actual and current planned shutdown dates. The information filed in September 2002 was modeled with the assumption that Gannon Units 1 - 4 would be able to run through the end of 2003. The result of the requested analysis is total fuel and net power transactions cost of $563,897,100[1] prior to jurisdictional separation or accounting for losses and taxes.

[1] The analysis assumes that Unit 6 is shut down October 1, 2003, and Units 3 and 4 are shut down October 15, 2003.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority, personally appeared J. Denise Jordan who deposed that the individuals listed in Tampa Electric Company's Index in response to Office of Public Counsel's Third Set of Interrogatories, (No. 46) and Third Set of Production of Documents, (Nos. 30-36), filed on July 21, 2003, in Docket No. 030001- EI, prepared or assisted with the responses to these interrogatories and production of documents to the best of her information and belief.

Dated at Tampa, Florida this 22nd day of August, 2003

J. Denise Jordan

Sworn to and subscribed before me this 22nd day of August, 2003

Paula K. Brown

My Commission expires December 4, 2004

Paula K Brown
My Commission DD0125068
Expires December 04, 2004

Gannon O / NRF
Scenario Analysis

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2003 (millions)		***Gannon O&M / NRF***		***Bayside Incremental***		***Total***		***Plan Savings***	
Scenario 1	$	23.0	$	0.9	$	23.9	$	(14.5)	GN 1-4 May 1, 2003
Scenario 2		21.0		1.1		22.1		(16.3)	GN 1-4 March 16, 2003
Scenario 3		28.5		0.5		29.0		(9.4)	GN 1-2 May 1, 2003 and GN 3-4 Sept 1
Scenario 4		22.0		1.0		23.0		(15.4)	GN 1-2 March 16, 2003 and GN 3-4 May 1, 2003
Scenario 5		27.5		0.5		28.0		(10.4)	GN 1-2 March 16, 2003 and GN 3-4 Sept 1, 2003
2004									
All Scenarios	$	9.0							No Gannon Units Operating (Includes Inventory Write-Off $3.3m, HP $0.3, Lay-up, Safety Demo $1.5, Facility Clean-up $.4) Labor / Fringe $1.3, Contingency $2.2)
		2003		***2004***					
Base Gannon	$	38.4	$	25.6					GN 1-4 Retired Sept 2004

Gannon O&M Scenario Savings.xls
09/16/2002

Tampa Electric Company

Calculation of O&M Savings
Related to the Early Shutdown of Gannon Units 1 Through 4

Line No.	Description	Amount	
1	2003 Estimated O&M Savings		$ 11,200,000
2	Additional Cost to Run Gannon 1 & 2 per week	153,846	
3	Annualized for actual 3 week extension Line 2 * 3		461,538
4	Additional Cost to Run Gannon 3 & 4 per week	277,777	
5	Annualized for actual 6 week extension Line 4 * 6		1,666,662
6	Estimated 2003 O&M Savings Line 1 - Line 3 - Line 5		$ 9,071,800
7	Estimated 2004 O&M Savings		$ 16,000,000

Line 1 per Bill Whale's August 26, 2002 presentation to officers, B.S. 551.

Line 2 per B.S. 705.
Scenario 3 vs. 5 shows $1 million difference in savings, with Gannon 1 & 2 operational until May 1, 2003 (Scenario 3) versus Gannon 1 & 2 operational until March 16, 2003 (Scenario 5).
Difference is 6.5 weeks @ $1 million, or 1 week =$153,846 per week.
3 weeks X $153,846 = $461,538 less savings than originally projected

Line 4 per B.S. 705.
Scenario 4 vs. 5 shows $5 million difference in savings, with Gannon 3 & 4 operational until May 1, 2004 (Scenario 4) versus Gannon 3 & 4 operational until September 1 (Scenario 5).
Difference is 18 weeks @ $5 million or 1 week =$277,777
6 weeks X $277,777 = $1,666,662 less savings than originally projected.

Line 7 per Bill Whale's August 26, 2002 presentation to officers, B.S. 551.
Note: B.S. 705 shows the Base Case O&M expense for Gannon as $25.6 million in 2004, as opposed to $9.0 million expense for "All Scenarios" which produces $15.6 million in savings for year 2004.