FILED SEP 23, 2016
DOCUMENT NO. 07775-16
FPSC - COMMISSION CLERK

Docket No. 160001-EI
Fuel and purchased power cost recovery clause with generating performance incentive factor.

Witness: Direct testimony of Mark Anthony Cicchetti
appearing on Behalf of the Staff of the Florida Public Service Commission

DATE FILED: September 23, 2016

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Mark Anthony Cicchetti. My business address is 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850.

Q. By who are you employed, and what is your position?

A. I am the Chief of the Bureau of Finance, Tax, and Cost Recovery at the Florida Public Service Commission.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Florida Public Service Commission staff.

Q. Please provide a brief summary of your educational background and professional experience.

A. I received a Bachelor of Science (BS) degree in Business Administration in 1980 from Florida State University and a Master of Business Administration (MBA) in Finance in 1981, also from Florida State University.

I have over 30 years of experience in utility regulation including 20 years as a consultant specializing in public utility finance, economics, and regulation. For 10 years I was a Project Manager and Manager of the Tallahassee, Florida Office of C.H. Guernsey & Co. (Guernsey) where I provided consulting services including the provision of expert testimony. My project responsibilities for Guernsey included cost of equity analysis, credit and capital market analysis, merger and acquisition analysis, utility valuation, demand-side management and energy efficiency analysis, and financial integrity analysis. For ten years prior to joining Guernsey, I was President of Cicchetti & Co., a financial research and consulting firm, where I also provided consulting services including the provision of expert testimony. Topics I provided expert testimony on included the cost of equity, the overall cost of capital, industry structure, capital structure, corporate structure, regulatory theory, incentive regulation, implementation of the leverage formula for water and wastewater utilities, and uniform rates. Prior to joining Guernsey I was the Chief of Arbitrage Compliance for the Florida Division of Bond Finance and the Chief of Finance for the Florida Public Service Commission. I am currently the Secretary/Treasurer of the Society of Utility and Regulatory Financial Analysts (SURFA) and previously have served as President, Secretary/Treasurer, and a member of the Board of Directors of SURFA. A copy of my Curriculum Vitae is included as Exhibit (MAC-1).

II. TESTIMONY OVERVIEW

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

A. The purpose of my testimony is to present a history of hedging in Florida in an effort to provide an understanding of how and why we arrived at where we are today regarding hedging and to provide the Commission with an alternative to the current hedging protocol. I will also provide an overview of the hedging practices of other state commissions.

Q. **What materials did you review and rely on in preparing your testimony?**

A. In preparing my testimony, I reviewed all Commission orders regarding hedging dating back to 2001; all staff recommendations, reports, and presentations on hedging; the transcript of the Commission's workshop on hedging held in 2011; the hedging-related testimony and exhibits of the witnesses of Gulf Power Company, Duke Energy Florida, Florida Power & Light Company, and Tampa Electric Company (Companies) in 2015 and in the current 2016 docket; the Companies' Risk Management Plans for 2016 and 2017; the hedging-related discovery in the 2016 Fuel Docket and in Docket No. 160096-EI; the Florida Supreme Court Order No. SC-1595 in <u>Citizens v. Graham</u>; a paper titled, "*White Paper Regarding Utility Hedging Regulation*" by Michael Gettings, prepared for the Washington Utilities and Transportation Commission, July 2015; and the article "*Hedging Under*

Scrutiny" by Julie Ryan and Julie Leiberman published by Public Utilities Fortnightly in 2012.

III. HISTORY OF FINANCIAL FUEL HEDGING IN FLORIDA

Q. When did Florida investor-owned electric utilities begin engaging in financial hedging of fuel costs?

A. In 1990, the New York Mercantile Exchange (NYMEX) introduced a natural gas futures contract and in 1992 the NYMEX introduced a natural gas options contract. Prior to that time, there were no widespread exchange-traded financial derivative products available to directly and effectively hedge natural gas prices. Also, prior to 1990, coal was a much more prevalent fuel source for electric generation. Coal was purchased through relatively fixed-cost, long-term contracts and its relatively stable price made financial hedging less necessary. Also, prior to 1999, natural gas prices were relatively low and stable. Exhibit (MAC-2) shows the monthly Henry Hub spot price of natural gas (Dollars per million Btu) for the period 1997 to 2016.

The market price of natural gas increased significantly between March 1999 and March 2001 and during that time Florida Power & Light Company (FPL) responded, in part, to the increasing market price of natural gas with limited financial hedging. Florida Power Corporation (FPC) (the predecessor company to Duke Energy Florida, LLC), Gulf Power Company (GPC), and Tampa Electric Company (TECO) began financial hedging in 2002.

Q. When did the Florida Public Service Commission officially first address financial hedging of fuel costs?

A. The Commission officially first addressed fuel hedging in the 2001 Fuel Docket, Docket No. 010001-EI. On September 11, 2001, the Commission issued Order No. PSC-01-1829-PCO-EI establishing issues for resolution in Docket No. 010001-EI that included issues directly related to fuel hedging.[1] On November 2, 2001, the Office of Public Counsel (OPC) filed a motion to defer consideration of the hedging-related issues listed in that Order to allow the parties additional time to explore those issues. By Order No. PSC-01-2273-PHO-EI,[2] OPC's motion was granted. The deferred issues listed in Order No. PSC-01-1829-PCO-EI were:

ISSUE 11: Has each investor-owned electric utility taken reasonable steps to manage the risks associated with its fuel transactions through the use of physical and financial hedging practices?

ISSUE 12: What is the appropriate regulatory treatment for gains and losses from hedging an investor-owned electric utility's fuel transactions through futures contracts?

ISSUE 13: What is the appropriate regulatory treatment for premiums received and paid for hedging an investor-owned electric utility's fuel transactions through options contracts?

ISSUE 14: What is the appropriate regulatory treatment for the transaction costs associated with an investor-owned electric utility hedging its fuel transactions?

ISSUE 18A: For the period March 1999 to March 2001, did FPL take reasonable steps to manage the risk associated with changes in natural gas prices?

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

Q. What procedures did the Commission use to address the deferred hedging issues?

A. The Commission directed staff to open a new docket to address the six deferred hedging issues and staff established Docket No. 011605-EI on November 27, 2001. Staff filed individual recommendations to address Issues 18A, relating to FPL, and 19D, relating to FPC,

---

[1] Order No. PSC-01-1829-PCO-EI, issued September 11, 2001, in Docket No. 010001-EI, *In re: Fuel and purchased power cost recovery clause and generating performance incentive factor*.

[2] Order No. PSC-01-2273-PCO-EI, issued November 19, 2001, in Docket No. 010001-EI, In re: *Fuel and purchased power cost recovery clause and generating performance incentive factor*.

on May 9, 2002, and June 6, 2002, respectively. Subsequently, the Commission issued Order Nos. PSC-02-0793-PAA-EI and PSC-02-0919-PAA-EI resolving Issues 18A and 19D, respectively.[3,4] Regarding the remaining issues, the parties engaged in settlement discussions and presented the Commission with a Proposed Resolution of Issues which the Commission approved by Order No. PSC-02-1484-FOF-EI.[5]

Q. What led the Commission to address the hedging issues cited above?

A. The market price of natural gas changed substantially from March 1999 to March 2001. The monthly average price of natural gas increased from $1.70 per 1000 cubic feet (MCF) in March 1999 to $8.06 per MCF in January 2001. By March 2001, the price dropped to $5.15 MCF.

In March 2001, the Commission granted FPC's petition for a mid-course correction to its fuel and purchased power cost recovery factors (factors) to collect a $29.4 million actual under-recovery for 2000 and a projected $73.0 million under-recovery for 2001. In April 2001, the Commission granted FPL's petition for a mid-course correction to its fuel and purchased power cost recovery factors to collect an actual $76.8 million under-recovery for 2000 and a projected $431.5 million under-recovery for 2001.

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

During the discovery process leading to the November 2001 hearing, staff reviewed

---

[3] Order No. PSC-02-0793-PAA-EI, issued June 11, 2002, in Docket No. 011605-EI, *In re: Review of investor-owned electric utilities' risk management policies and procedures*.
[4] Order No. PSC-02-0919-PAA-EI, issued July 8, 2002, in Docket No. 011605-EI, *In re: Review of investor-owned electric utilities' risk management policies and procedures*.
[5] Order No. PSC-02-1484-FOF-EI, issued October 10, 2002, in Docket No. 011605-EI, *In re: Review of investor-owned electric utilities' risk management policies and procedures*.

information that indicated FPL and FPC may not have reacted sufficiently to the price signals that the natural gas commodity market experienced from March 1999 to March 2001. Consequently, as described above, the Commission ultimately directed staff to open a new docket to address the hedging issues and staff established Docket No. 011605-EI.[6]

Q. What were the Commission's findings in Docket No. 011605-EI?

A. Regarding FPL's and FPC's prudence in managing the risks associated with changes in natural gas prices, the Commission found that FPL and FPC both reasonably managed the risks associated with changes in natural gas prices for the period March 1999 through March 2001.[7,8]

Q. What steps did FPL and FPC take to manage the risks associated with changes in natural gas prices?

A. To mitigate the risks associated with changes in natural gas prices, FPL and FPC increased production at generation units that did not burn natural gas and utilized the fuel-switching capabilities of several generating units to burn oil instead of natural gas. The staff noted that FPL also engaged in two types of wholesale energy transactions to mitigate its purchased power costs and engaged in physical hedging and limited financial hedging to manage the risks associated with the changes in fuel prices.

Q. What were the Commission's findings regarding the remaining issues in Docket No. 011605-EI?

A. Regarding the remaining issues, the Commission approved a Proposed Resolution of Issues that resolved the remaining issues in the docket.[9] The Proposed Resolution of Issues

---

[6] See Staff Recommendation, dated May 9, 2002, in Docket No. 011605-EI.

[7] Order No. PSC-02-0793-PAA-EI, issued June 11, 2002, in Docket No. 011605-EI, *In re: Review of investor-owned electric utilities' risk management policies and procedures*, at p. 5.

[8] Order No. PSC-02-0919-PAA-EI, issued July 8, 2002, in Docket No. 011605-EI, *In re: Review of investor-owned electric utilities' risk management policies and procedures*, at p. 6.

[9] Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, In *re: Review of investor-owned electric utilities' risk management policies and procedures*.

was signed and supported by FPL, FPC, TECO, the Florida Industrial Power Users Group, and OPC. GPC agreed to the settlement at the hearing based upon a modification made during the hearing. The Proposed Resolution of Issues was comprised of seven components and established the framework for fuel hedging that the Commission and the parties largely continue to follow. In 2008, in response to petitions filed by FPL, the Commission modified Order No. PSC-02-1484-FOF-EI (2002 Hedging Order) for clarification.

Q. What were the components of the Proposed Resolution of Issues?

A. The 2002 Hedging Order, included the components of the Proposed Resolution of Issues which are attached as Exhibit (MAC-3). In summary, the seven components of the resolution of issues state: (1) each investor-owned electric utility recognizes the importance of managing price volatility in the fuel and purchased power it purchases to provide electric service to its customers; (2) each investor-owned electric utility will submit a risk management plan for fuel procurement at the time of its projection filing in the fuel and purchased power cost recovery docket each year; (3) each investor-owned electric utility shall be authorized to charge/credit to the fuel and purchased power cost recovery clause its non-speculative, prudently-incurred commodity costs and gains and losses associated with financial and/or physical hedging transactions; (4) each investor-owned electric utility may recover through the fuel and purchased power cost recovery clause prudently-incurred incremental operating and maintenance expenses incurred for the purpose of initiating and/or maintaining a new or expanded non-speculative financial and/or physical hedging program designed to mitigate fuel and purchased power price volatility for its retail customers; (5) each investor-owned utility shall provide, as part of its final true-up filing in the fuel and purchased power cost recovery docket, the volumes of fuel hedged, the types of hedges utilized, the average period of each hedge, and the actual costs of the hedges; (6) no party shall seek approval of a hedging incentive program earlier than the time of its projection filing for the

2004 fuel and purchased power cost recovery period, and; (7) the proposed resolution may be executed in counterparts.[10]

Q. What modifications were made to the Hedging Order in 2008?

A. The 2002 Hedging Order did not provide, with specificity, the time period for which prudence would be established nor did it require the necessary information for making a prudence determination. Order No. PSC-08-0316-PAA-EI specified that the four largest investor-owned electric utilities would file a Hedging Information Report by August 15 of each year detailing their current year hedging transactions during the months of January through July of that current year.[11] That modification to the 2002 Hedging Order facilitated the Commission's ability to determine prudence each year in the annual fuel clause hearing by ensuring the Commission had the necessary information for each year to make such a determination.

On August 5, 2008, FPL filed a petition for approval of Hedging Order Clarification Guidelines. FPL proposed the Hedging Order Clarification Guidelines in response to asymmetric reactions of certain stakeholders to fuel hedging gains and losses. In its petition FPL stated:

> When the Commission approved the 2002 Hedging Resolution, support for hedging was strong and consistent among the stakeholders. Unfortunately, the reaction of certain stakeholders over the ensuing years has not been symmetric when hedging programs show gains and when they show losses. Support for hedging has generally been strong during periods of rising fuel prices, when hedging programs are showing gains, but has

---

[10] Order No. PSC-02-1484-FOF-EI at pp. 5-7.

[11] Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, in Docket No. 080001-EI, In *re: Fuel and purchased power cost recovery clause and generating performance incentive factor*.

> waned when prices are falling and hedging programs are showing losses. IOU shareholders receive no special benefit or reward when hedging programs result in gains, but this observed asymmetry raises the specter that shareholders might be exposed to risks of non-recovery when hedging programs result in losses. This imbalance of risks and rewards can increase the perceived financial risk of the IOU's and ultimately increase their cost of capital.
>
> The Hedging Guidelines are designed to mitigate against this asymmetry by reaffirming and clarifying the Commission's support for hedging as an appropriate means of managing the impacts of fuel price volatility.[12]

By Order No. PSC-08-0667-PAA-EI, the Commission approved the Hedging Order Guidelines proposed by FPL.[13] In its order, the Commission stated

> By approving FPL's proposed guidelines, we demonstrate our support for hedging. We retain our discretion to determine the prudence of hedging results and acknowledge that the guidelines do not bind us in our review of a utility's hedging practices.

Between 2009 and 2015, no specific hedging-related issues were addressed in the fuel cost recovery dockets. In 2015, as part of the Fuel and Purchased Power Adjustment and Generating Performance Factor Clause (Fuel Docket) proceedings, testimony and other evidence was presented on hedging and hedging-related issues.

Q. What were the hedging and hedging related issues addressed in the 2015 Fuel

---

[12] Petition of Florida Power & Light Company for approval of Hedging Guidelines and For Leave to Withdraw its January 31, 2008 VMM Petition, Docket No. 080001-EI, at p. 3.

[13] Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI, In *re: Fuel and purchased power cost recovery clause and generating performance incentive factor*, at p. 12.

Docket?

A. As stated in Order No. PSC-15-0586-FOF-EI,[14] the issues addressed were: (1) the significant opportunity costs of hedging programs that IOUs incurred as part of fuel costs paid by customers; (2) whether the volatility of natural gas prices has declined to the point where hedging is no longer effective or necessary; and (3) whether conditions in the natural gas market are stable and eliminate the need for hedging.

Q. What did the Commission conclude based on the hearing in the 2015 Fuel Docket?

A. The Commission decided to allow hedging to continue and directed staff and the parties to explore possible changes to the current hedging protocol. Order No. PSC-15-0586-FOF-EI stated:

> Our decision to continue hedging at this time is based on the evidence presented in this record which in large part consists of arguments to either completely eliminate hedging or to continue the procedures in place at this time. There was no written testimony from any party and very limited cross-examination on possible changes to the manner in which the IOUs conduct natural gas financial hedging activities or alternatives to hedging: cost sharing of hedging gains and losses between the IOUs and ratepayers, alternative accounting treatment for recovery of gains and losses (VMM program), or imposing limits on the percentage of natural gas purchases hedged. All witnesses agreed that any changes to the hedging protocol should be prospective and that the current hedges should be

[14] Order No. PSC-15-0586-FOF-EI, issued December 23, 2015, in Docket No. 150001-EI, *In re: Fuel and purchased power cost recovery clause and generating performance incentive factor*.

> allowed to terminate on their original contract dates. Notwithstanding our decision on hedging, we recognize that the cost of this program is significant by any measure for each Florida IOU and deserves further analysis. Therefore, we direct our staff, in conjunction with the parties to this docket, to explore possible changes to the current hedging protocol that will minimize potential losses to customers.[15]

Q. Did the Commission staff and the parties explore possible changes to the current hedging protocol?

A. Yes. On January 25, 2016, staff held an informal, noticed meeting with interested parties to discuss options and procedures for possible changes to the current hedging protocol to minimize potential losses to customers. Representatives from DEF, FPL, TECO, and GPC participated in the meeting. Staff also conducted discovery.

On April 22, 2016, FPL, TECO, and Gulf (IOUs) filed a joint petition in Docket No. 160096-EI seeking approval of modifications to their respective Risk Management Plans. DEF joined in the petition but stated it had the latitude to make the changes agreed to by the IOUs without modifying its current plan. The IOUs' proposed modifications were company-specific and each proposed to: (1) reduce their respective annual maximum percentage of fuel purchases targeted for hedges; and (2) reduce the period of time over which hedges may be placed pursuant to each respective Risk Management Plan.

Q. Did the Commission approve the IOUs' petition to modify their respective Risk Management Plans?

A. Yes. The Commission approved the IOUs' petition in Order No. PSC-16-0247-PAA-

[15] Order No. PSC-15-0586-FOF-EI, issued December 23, 2015, in Docket No. 150001-EI, *In re: Fuel and purchased power cost recovery clause and generating performance incentive factor*, at p. 9.

EI.[16] In that order the Commission stated:

> This reduction in the percentage of natural gas hedged is a step in the right direction. However, we continue to be concerned about this issue and the high costs experienced by electric ratepayers for natural gas in excess of the market price. We urge the our (sic) staff, the investor-owned utilities, and the parties to provide us with other evidence-based options to further limit customer exposure to risks of hedging in the forthcoming fuel cost recovery docket, Docket No. 160001-EI, scheduled for November of this year.

Q. Was Order No. PSC-16-0247-PAA-EI protested?

A. Yes. On July 15, 2016, OPC filed a timely protest of Order No. PSC-16-0247-PAA-EI and requested an evidentiary hearing.[17] By Order No. PSC-16-0301-PCO-EI, Commissioner Graham, as Prehearing Officer, consolidated Docket No. 160096-EI into the 2016 Fuel Docket, Docket No. 160001-EI, for all purposes.[18]

On September 20, 2016, staff and the parties held the first issue identification meeting for Docket No. 160001-EI, and the following two hedging-related issues were agreed to by all parties:

<u>Issue 1A</u>: Is it in the consumers' best interest for the utilities to continue natural gas financial hedging activities?

<u>ISSUE 1B</u>: What changes, if any, should be made to the manner in which electric utilities

---

[16] Order No. PSC-16-0247-PAA-EI, issued June 27, 2016, in Docket No. 160096-EI, *In re: Joint petition for approval of modifications to risk management plans by Duke Energy Florida, Florida Power & Light Company, Gulf Power Company and Tampa Electric Company*, at p. 7.

[17] See Petition Protesting & Requesting Evidentiary Hearing On The Proposed Agency Action, filed July 15, 2016, in Docket No. 160096-EI, *In re: Joint petition for approval of modifications to risk management plans by Duke Energy Florida, Florida Power & Light Company, Gulf Power Company and Tampa Electric Company.*

[18] Order No. PSC-16-0301-PCO-EI, issued July 28, 2016, in Docket No. 160096-EI, *In re: Joint petition for approval of modifications to risk management plans by Duke Energy Florida, Florida Power & Light Company, Gulf Power Company and Tampa Electric Company.*

conduct their natural gas financial hedging activities?

IV. ALTERNATIVES TO THE CURRENT HEDGING PROTOCOL

Q. As urged by the Commission in Order No. PSC-16-0247-PAA-EI, has the staff explored other evidence-based options to limit customer exposure to the risks of hedging?

A. Yes. While conducting research regarding financial hedging of fuel costs by regulated utilities, staff became aware of risk-responsive hedge strategies that rely on the principles of quantitative finance to provide an effective framework for robust hedge practices. Analysis of the risk-responsive hedging strategies indicated they are superior to the typical targeted-volume approach generally practiced by regulated investor-owned utilities and should help minimize potential losses to customers. Consequently, staff retained an expert, Michael Gettings, to provide testimony regarding risk-responsive hedging strategies in this docket. Mr. Gettings testimony presents a hedging framework for the Commission to consider as an alternative to the current hedging protocol.

Q. If the Commission were to adopt the approach recommended by Mr. Gettings, could the approach be implemented in 2017?

A. Possibly. It will take time for the IOUs to familiarize themselves with the concepts, to acquire the necessary resources, and to formulate strategies. However, if it is not feasible to implement a risk-responsive hedging strategy as soon as 2017, I recommend the Commission implement, in 2017, the modifications requested in Docket No. 160096-EI by the IOUs to their respective 2017 Risk Management Plans to: (1) reduce their respective annual maximum percentage of fuel purchases targeted for hedges; and (2) reduce the period of time over which hedges may be placed.

I also recommend that beginning April 30, 2017, the Commission require the IOUs to develop and provide contemporaneous weekly risk measurement and monitoring, from the customers' perspective, to be reported quarterly as outlined by Michael Gettings in his direct testimony and shown on Exhibit (MAG-2).

Q. Why do you recommend the Commission implement, for 2017, the modifications requested by the IOUs to their respective Risk Management Plans in Docket No. 160096-EI and require the IOUs provide contemporaneous weekly risk measurement and monitoring, from the customers' perspective, as outlined by Michael Gettings in his direct testimony?

A. If the IOUs cannot implement a risk-responsive hedging protocol in 2017, I recommend 2017 be used as a transition year with full implementation in 2018. I recommend that the modifications requested by the IOUs to their respective Risk Management Plans in Docket No. 160096-EI be implemented in 2017. Those modifications can reduce potential losses to be recovered from the customers compared to the current hedging protocol. I do not recommend hedging be eliminated. Hedging is beneficial because it reduces customer pain when prices spike thereby creating value for customers. Customers derive greater value from upside cost mitigation than they forego from hedge losses because hedge losses tend to occur when prices are declining. Natural gas prices are lognormally distributed. That means the magnitude of significant cost increases tends to be much greater than the magnitude of significant cost decreases.

Requiring the IOUs to provide contemporaneous weekly risk measurement and monitoring, from the customers' perspective, as outlined by Michael Gettings in his direct testimony, will allow the IOUs to develop a more robust structure for hedging strategies while not being overly prescriptive. Using more robust quantitative tools, deployed in a risk-responsive fashion, should reduce customer costs relative to the volume-targeted hedging currently employed by the IOUs.

Q. Do the IOUs 2017 Risk Management Plans reflect the changes proposed by the

IOUs in their petition in Docket No. 160096-EI?

A. GPC's Risk Management Plan reflects the modifications proposed in Docket No. 160096-EI. FPL's, DEF's and TECO's Risk Management Plans do not reflect the modifications proposed in Docket No. 160096-EI.

V. HEDGING PRACTICES OF OTHER STATE COMMISSIONS

Q. Have you reviewed research regarding the hedging practices of other state commissions?

A. Yes. In June 2016, the Commission's Division of Industry Development and Market Analysis (IDM) conducted a survey, through the National Association of Regulatory Utility Commissioners, to obtain current information regarding the hedging practices of other state commissions. Twelve states responded. Consistent with other research regarding state commission hedging practices, there was a wide array of responses. Approaches varied from encouraging utilities to hedge to ending hedging programs. Exhibit (MAC-4) is a summary of the results of IDM's survey.

In a paper published by Public Utilities Fortnightly in 2012 titled "Hedging Under Scrutiny," authors, Julie Ryan and Julie Lieberman of Concentric Energy Advisors cited a 2008 survey conducted by the National Regulatory Research Institute and a 2009 survey conducted by the American Gas Association that indicated most state commissions either supported or were neutral to hedging.[19] The article went on to describe how various state commissions are re-assessing hedging practices and how in some cases hedging programs have been scrutinized and continued without modification, while in other cases, hedging programs have been targeted for additional review or have been suspended. One relevant conclusion of the article was:

> One benefit arising from the increased focus on utility hedging

---

[19] Julie Ryan and Julie Lieberman, "Hedging Under Scrutiny," *Public Utilities Fortnightly*, Volume No. 150, No.2, February 2012, P.12.

> is that regulators and stakeholders have grown increasingly sophisticated about commodity markets and hedging, and some might support more complex programs in the future. However, the more discretionary a program design, the more critical decisional documentation and transparent processes become. Further, there must be rigor and consistency in how hedging is adjusted in different market price environments. It will be important in the design and approval stage that the hedging program has clear triggers for when hedging decisions will be executed. During the implementation stage, it will be important for utilities to document information that was known to them at the time hedges were transacted to demonstrate that reasonable actions were taken, consistent with program design.

A copy of the article "Hedging Under Scrutiny" is attached as Exhibit (MAC-5).

Q. Does this conclude your testimony?

A. Yes.

MARK ANTHONY CICCHETTI

EDUCATION:

M.B.A. – Finance; Florida State University, Tallahassee, Fl. 1981
B.S. – Business Administration; Florida State University, Tallahassee, Fl. 1980

EXPERIENCE:

2010-present **Bureau Chief, Finance, Tax, and Cost Recovery, Florida Public Service Commission, Tallahassee, Florida, 32399**

Advise the Commission regarding all aspects of public utility finance, tax, and economics for all utility industries. Oversee the Bureau of Finance, Tax and Cost Recovery supervisors and analysts. Testify as an expert witness as needed. Preside over rate cases assigned to the bureau. Review and recommend legislation, participate in rule making related to finance and taxation, and review and monitor utility security issuances. Member of the bond team comprised of Duke Energy, Florida and Commission personnel assigned in 2016 to structure, market, and issue $1.3 billion of securitized nuclear asset-recovery bonds.

2000-2009 **Project Manager, C. H. Guernsey & Company, Tallahassee, Florida 32309.**

Provided financial and economic research and analysis and consulting services including the provision of expert testimony. Project responsibilities included cost of equity analysis, credit and capital market analysis, merger and acquisition analysis, utility valuation, demand-side management and energy efficiency analysis, financial integrity analysis, territorial disputes, decoupling analysis, automatic adjustment formula analysis, leverage formula analysis, cost of service and rate design, peer analysis, acquisition adjustments, allowance for funds prudently invested, and appropriate regulatory treatment of gains and losses on sale.

2010 and **Principal, Cicchetti & Co., Tallahassee, Florida 32311**

1990-2000 Provided financial research and consulting services, including the provision of expert testimony, in the areas of public utility finance and economics. Subjects addressed included the cost of equity, the overall cost of capital, capital structure, corporate structure, industry structure, regulatory theory, incentive regulation, the credit and capital markets, cross-subsidization, uniform rates, the appropriate treatment of construction work in progress, construction cost recovery charges, and used and useful property.

1990 - 2000 **Manager, Arbitrage Compliance, Florida Division of Bond Finance, Tallahassee, Florida**

Was responsible for assuring $16 billion of State of Florida tax-exempt securities remained in compliance with the federal arbitrage requirements enacted by the Tax Reform Act of 1986. Designed and implemented the first statewide arbitrage compliance system which included data gathering, computation, and financial reporting subsystems. Provided investment advice and analysis to trust fund administrators on how to maximize yields while remaining in compliance with the federal arbitrage regulations. In 1999 and 2000, informed responsible parties how they could restructure advanced refunding escrow accounts that resulted in over $1 million of additional earnings. In 2000, obtained a favorable private letter ruling from the IRS regarding temporary investments which resulted in over $10 million of cash savings.

PROFESSIONAL ACTIVITIES:

Secretary/Treasurer – Society of Utility and Regulatory Financial Analysts (Present)
Board of Directors - Society of Utility and Regulatory Financial Analysts (1989 - 1995)
President - Society of Utility and Regulatory Financial Analysts (1992 - 1994)
Secretary/Treasurer - Society of Utility and Regulatory Financial Analysts (1990 - 1992)
Certified Rate of Return Analyst, (1992)
3rd Place, Competitive Papers Session, sponsored by Public Utilities Reports, Inc. in conjunction with the University of Georgia and Georgia State University. September, 1986
Meritorious Service Award, computer revenue requirement modeling, Florida Public Service Commission. October, 1986

ARTICLES AND PUBLICATIONS:

"Gas Distribution: Now a Higher-Risk Business," *Public Utilities Fortnightly,* September 1, 2002.

"Irregular Incentives," *Public Utilities Fortnightly*, June 15, 1993.

"The Quarterly Discounted Cash Flow Model, Effective and Nominal Rates of Return, and the Determination of Revenue Requirements for Regulated Public Utilities," *National Regulatory Research Institute Quarterly Bulletin*, June 1989.

"Adjustments to the Capital Structure: Pro-Rata versus the Tracing of Funds," FPSC Working Paper, March 1986.

"Reconciling Rate Base and Capital Structure: The Balance Sheet Method," *Public Utilities Fortnightly,* June 27, 1985.

Henry Hub Natural Gas Spot Price (Dollars per Million Btu)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1997	3.45	2.15	1.89	2.03	2.25	2.20	2.19	2.49	2.88	3.07	3.01	2.35
1998	2.09	2.23	2.24	2.43	2.14	2.17	2.17	1.85	2.02	1.91	2.12	1.72
1999	1.85	1.77	1.79	2.15	2.26	2.30	2.31	2.80	2.55	2.73	2.37	2.36
2000	2.42	2.66	2.79	3.04	3.59	4.29	3.99	4.43	5.06	5.02	5.52	8.90
2001	8.17	5.61	5.23	5.19	4.19	3.72	3.11	2.97	2.19	2.46	2.34	2.30
2002	2.32	2.32	3.03	3.43	3.50	3.26	2.99	3.09	3.55	4.13	4.04	4.74
2003	5.43	7.71	5.93	5.26	5.81	5.82	5.03	4.99	4.62	4.63	4.47	6.13
2004	6.14	5.37	5.39	5.71	6.33	6.27	5.93	5.41	5.15	6.35	6.17	6.58
2005	6.15	6.14	6.96	7.16	6.47	7.18	7.63	9.53	11.75	13.42	10.30	13.05
2006	8.69	7.54	6.89	7.16	6.25	6.21	6.17	7.14	4.90	5.85	7.41	6.73
2007	6.55	8.00	7.11	7.60	7.64	7.35	6.22	6.22	6.08	6.74	7.10	7.11
2008	7.99	8.54	9.41	10.18	11.27	12.69	11.09	8.26	7.67	6.74	6.68	5.82
2009	5.24	4.52	3.96	3.50	3.83	3.80	3.38	3.14	2.99	4.01	3.66	5.35
2010	5.83	5.32	4.29	4.03	4.14	4.80	4.63	4.32	3.89	3.43	3.71	4.25
2011	4.49	4.09	3.97	4.24	4.31	4.54	4.42	4.06	3.90	3.57	3.24	3.17
2012	2.67	2.51	2.17	1.95	2.43	2.46	2.95	2.84	2.85	3.32	3.54	3.34
2013	3.33	3.33	3.81	4.17	4.04	3.83	3.62	3.43	3.62	3.68	3.64	4.24
2014	4.71	6.00	4.90	4.66	4.58	4.59	4.05	3.91	3.92	3.78	4.12	3.48
2015	2.99	2.87	2.83	2.61	2.85	2.78	2.84	2.77	2.66	2.34	2.09	1.93
2016	2.28	1.99	1.73	1.92	1.92	2.59	2.82	2.82				

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 9/21/2016

Source: Energy Information Administration

ATTACHMENT A

PROPOSED RESOLUTION OF ISSUES
DOCKET NO. 011605-EI
AUGUST 9, 2002

Components of Proposed Resolution:

1. Each investor-owned electric utility recognizes the importance of managing price volatility in the fuel and purchased power it purchases to provide electric service to its customers. Further, each investor-owned electric utility recognizes that the greater the proportion of a particular fuel or purchased power it relies upon to provide electric service to its customers, the greater the importance of managing price volatility associated with that energy source.

2. Each investor-owned electric utility shall submit to the Commission, at the time of its projection filing in the fuel and purchased power cost recovery docket each year, its risk management plan for fuel procurement. For purposes of this proposed resolution, each risk management plan shall address the following items set forth in Exhibit TFB-4 to the prefiled testimony of Todd F. Bohrmann in this docket: item numbers 1, 3 (to the extent possible), 4, 5, 6, 7, 8, 9, 13, 14, and 15. The information provided as part of each risk management plan should emphasize the utility's numerical assessment of an acceptable level of price risk for each type of fuel and for purchased power, the method used to determine the acceptable level of risk, identification of the mechanisms to mitigate risk above the acceptable level, and a valuation of that risk in dollars, where possible. The information provided as part of each risk management plan shall include the quantities of fuel and purchased power that each utility expects to hedge through physical and financial hedging, to the extent such forecasts are made. Filing of such risk management plans for informational purposes shall not constitute approval or disapproval by the Commission. In addition, each investor-owned electric utility shall submit, as part of its final true-up filing in the fuel and purchased power cost recovery docket each year, a report indicating the success of its risk management activities with respect to the objectives set forth in its risk management plan.

3. Each investor-owned electric utility shall be authorized to charge/credit to the fuel and purchased power cost recovery clause its non-speculative, prudently-incurred commodity costs and gains and losses associated with financial and/or physical hedging transactions for natural gas, residual oil, and purchased power contracts tied to the price of natural gas. Examples of such items include transaction costs associated

ATTACHMENT A

with derivatives (e.g., fees and commissions), gains and losses on futures contracts, premiums on options contracts, and net settlements from swaps transactions. Each utility choosing to engage in such transactions shall maintain records of each transaction for Commission audit purposes.

4. Each investor-owned electric utility may recover through the fuel and purchased power cost recovery clause prudently-incurred incremental operating and maintenance expenses incurred for the purpose of initiating and/or maintaining a new or expanded non-speculative financial and/or physical hedging program designed to mitigate fuel and purchased power price volatility for its retail customers each year until December 31, 2006, or the time of the utility's next rate proceeding, whichever comes first. The base period for determining incremental expenses as described above is the year 2001 (using actual expenses), except for utilities with rates approved based on Minimum Filing Requirements (MFR) in rate reviews conducted since 2001, in which case the projected rate year is the base period (using projected expenses). For purposes of calculating the incremental operating and maintenance expenses for applicable periods of either the initiating or terminating year of this fuel clause recovery arrangement, the corresponding period in the base year shall be the basis for determining recoverable incremental expenses. In September of each year from 2002 through 2006, as part of the Projected Fuel Filing, each utility shall provide an itemization of the projected operating and maintenance expenses for the projected period by functional category for which fuel cost recovery is requested (the incremental expense). Such itemizations shall include allocations, where appropriate, of such costs between financial and physical hedging expense. All base year and recovery year FERC subaccount operating and maintenance expense amounts associated with financial and physical hedging activities shall be included in the Fuel Clause Final True-up filing each April during the years 2003 through 2007, including the difference between the base year and recovery year expense amounts, then summed, yielding a total incremental hedging amount which may be compared for cost recovery review purposes to the requested cost recovery amount produced in the Projected Filing for the recovery year.

5. Each investor-owned utility shall provide, as part of its final true-up filing in the fuel and purchased power cost

recovery docket, the following information: (1) the volumes of each fuel the utility actually hedged using a fixed price contract or instrument; (2) the types of hedging instruments the utility used, and the volume and type of fuel associated with each type of instrument; (3) the average period of each hedge; and (4) the actual total cost (e.g., fees, commissions, options premiums, futures gains and losses, swaps settlements) associated with using each type of hedging instrument.

6. This proposed resolution is intended to resolve all issues remaining for consideration in this docket, including disposition of the hedging incentive programs proposed in this docket by Florida Power Corporation and Florida Power & Light Company. No party to this docket shall seek approval of a hedging incentive program earlier than the time of its projection filing for the 2004 fuel and purchased power cost recovery period. This proposed resolution is not intended to apply to Florida Public Utilities Company.

7. This proposed resolution may be executed in counterparts, and all such counterparts shall constitute one instrument binding on the signatories, notwithstanding that all signatories are not signatories to the original or the same counterpart. Facsimile transmission of an executed copy of this Agreement shall be accepted as evidence of a party's execution of the Agreement.

* The Commission will review the prudence of each IOU's hedging transactions, including financial hedging transactions, as part of its annual fuel and purchased power cost recovery proceedings. Prudence shall be determined under established legal standards.

* No implication concerning the relative merits of using financial versus physical hedging techniques should be drawn from this proposed resolution.

* "Speculative" refers to physically and/or financially purchasing more of a commodity than one is expected to consume, or physically and/or financially selling more of a commodity than one owns.

Utility Hedging Practices

In June 2016 FPSC staff, through NARUC, sent a set of questions to the members of the NARUC Staff Subcommittee on Electricity, in order to obtain current information on other states' hedging practices. A summary of the responses follows.

Connecticut

Connecticut is a deregulated market.

Delaware

Following what it described as "disappointing" results from unrestricted natural gas hedging programs from 2000 to 2008, the Delaware Public Service Commission issued an order modifying future practices. In October 2009 the Commission adopted a non-discretionary hedging program for Delmarva Power & Light Company in which 50 percent of projected purchase requirements and storage injections are to be hedged on a pro rata basis (one-twelfth each month) over the 12-months preceding the month in which the physical gas is to be delivered to customers.

Georgia

From 2007 to 2012, Georgia Power Company was authorized to hedge up to 75 percent of its projected natural gas fuel burn, utilizing a 60-month hedging window. In November 2012, the Georgia Public Service Commission amended its hedging program by instituting budget caps so that the total of option premiums and net settlements from financial positions would not exceed hard caps. The caps were set at $45 million (2013), $40 million (2014), and $30 million for 2015 and 2016. In December 2015, at the request of Georgia Power Company the Georgia Commission modified its hedging program, eliminating hard caps, allowing Georgia Power Company to hedge up to 50 percent of its projected natural gas fuel burn in any given month and granted a 48-month hedging window.

Illinois

Illinois electric markets are restructured and, with limited exceptions, load serving entities are free to contract for supply and, in doing so, hedge as they see fit. For customers that do not elect competitive supply and remain on a default bundled service provided by their utility, supply is purchased on behalf of the utility/customer by the Illinois Power Agency (IPA). The IPA does hedge by laddering supply purchases. To a lesser extent, there is also choice in Illinois gas markets and suppliers of gas transportation customers are permitted to hedge at their discretion. Gas utilities that purchased gas on behalf of their customers are also permitted to hedge. Gas utilities have hedged since 2000 and continue to hedge through a broad array of financial hedging tools as well as making use of gas storage. Gas utilities typically discuss their hedging with ICC Staff annually. Gas hedging activities are not made publicly available. Hedging practices are subject to prudence evaluations in each utility's annual fuel costs reconciliation.

Kentucky

In March 2015, the Kentucky Public Service Commission denied Duke Energy's request to continue its hedging program. The Kentucky Commission determined customer benefits were not significant enough to justify extension of the hedging program.

Louisiana

The Louisiana Public Service Commission is developing a long-term natural gas hedging pilot program. Under what is expected to be a three-year pilot program, investor-owned utilities (IOUs) would be required to consider a range of long-term gas procurement strategies. The Louisiana Commission found that most of the state's IOUs purchased a substantial amount of natural gas through short-term contracts, which it determined to be a higher risk strategy.

Minnesota

The three largest natural gas utilities are allowed to use physical contracts and financial instruments for hedging purposes. The requests (petitions) are for variances to the Minnesota Public Service Commission rules that apply to purchased gas adjustment (PGA) cost recovery mechanisms. The rule variances allow cost recovery through the automatic cost recovery mechanisms (riders) even though hedging costs are not defined in these rules as a cost of gas.

The Commission has generally accepted reduction in price volatility as a reasonable goal. However, the Commission has not specifically required hedging or, on the other hand, disallowed recovery of any costs associated with hedging. Cost recovery for hedging is typically allowed when the hedging activity stays within prescribed guidelines that are set in advance on a case-by-case basis at the utilities' request.

Nevada

The Nevada Commission ended hedging programs citing declining price volatility.

New York

New York state's major electric utilities are not vertically integrated and generally purchase power from the New York Independent System Operator or through bilateral contracts. As a result, the utilities generally do not hedge fuel, but instead hedge their market purchases, primarily through financial contracts such as swaps and options. The New York Public Service Commission (NYPSC) requires the major electric (and gas) utilities to mitigate the supply price volatility only for their full service mass market customers, i.e. those residential and small non-residential customers that opt to purchase supply from the utility rather than a competitive Energy Service Company. The utilities are not allowed to hedge for their larger non-residential customers, although the majority of such customers opt to receive their supply from competitive energy service companies.

North Carolina

As the electric utilities in North Carolina started adding significant amounts of gas-fired generation, the North Carolina Utilities Commission encouraged the utilities to consider hedging natural gas purchases to manage the volatility of natural gas prices. The Commission does not require hedging and has not established hedging policies for the utilities to follow. Instead, the prudency of all fuel costs incurred, including hedging costs, are subject to review in the annual fuel charge adjustment proceedings for each utility. To date, the utilities have been allowed to recover the natural gas hedging-related costs that have been incurred.

Oregon

In March, 2015, the Public Utility Commission of Oregon opened a docket to explore the benefits and risks of the long term hedging policies of Northwest Natural Gas Company. The docket remains open at this time.

Washington

The Washington Utilities and Transportation Commission allows hedging. The Commission does not have explicit policies on hedging; however, companies are expected to act in a prudent manner in making fuel or gas purchases.

Companies serving Washington’s ratepayers mainly use a programmatic approach in their hedging, i.e., purchasing physical or financial futures contracts systematically prior to the delivery date, which is normally within one-year of its expected need. The Washington Commission has an active docket on gas hedging and is working with a consultant to reassess the state’s energy utilities’ current approach.

Published on *Fortnightly* (http://www.fortnightly.com)

The new world of gas supply, brought about by shale development, the economic downturn, and expanded gas infrastructure, has caused regulatory stakeholders to challenge utility gas supply hedging programs.

Hedging, a common feature of utility risk management practices, serves as a tool to stabilize prices, protect customers from market volatility, and insure against unexpected price spikes. However, regulatory commissions and intervenors are challenging the merits of their utilities' hedging programs with increasing frequency, questioning whether the risk mitigation benefits of hedging
have justified the associated costs, and whether customers are paying for insurance to manage a risk that might no longer exist.

Concerns raised by commission staff or other stakeholders relating to the cost of utility hedging programs has led to an emerging trend of greater commission and stakeholder involvement in assessing such programs' efficacy. Regulatory commissions are asking utilities to provide written justification of their hedging practices, applying pressure on utilities to work with stakeholders to resolve hedging differences through collaborative processes and to find common ground on the risk-reward spectrum. In some cases, risk management hedging programs have been suspended until there are visible increases in volatility and market prices.

Utilities that engage stakeholders in a dialogue now about their risk-management practices can ensure hedging remains a viable tool for limiting exposure to future price volatility.

Costs Incurred and Avoided

This shift toward re-assessing hedging practices is relatively recent. In 2008, a survey conducted by the National Regulatory Research Institute (NRRI) indicated that most commissions in the U.S. either supported or were neutral to hedging.[1] This was reinforced in a follow-up survey the AGA conducted in 2009.[2] Among more than 100 respondents, over 90 percent said their commissions allowed financial hedging of commodity price risk. However, only a very small number of commissions required utilities to engage in financial hedging.

Push-back on utility hedging typically begins with intervenors. Ultimately, however, most administrative law judges and commissions generally support hedging. While intervenors often recommend disallowance of hedging costs, commissions generally accept that the goal of hedging is price stability and not "to beat the market." As a result, cost disallowance decisions by commissions have been rare.[3] But, in an environment where utility customers are experiencing across-the-board rate increases, it isn't surprising that commissions would encourage utilities to evaluate changes to their hedging programs.

Intervenors have tended to take a retrospective view when evaluating the efficacy of hedging programs. While it's tempting to look at historical hedging based on current information and perfect hindsight, the regulatory standard for what is reasonable and prudent must consider the availability of information and what was known at the time hedging decisions were made. This is the standard commissions have adopted when reviewing historical hedging costs.

Many stakeholders have focused on costs associated with hedging, but there has been less focus by all parties on avoided cost analysis. In several instances, success—or lack thereof—has been measured by comparing the hedged prices to spot market prices. The costs have included net premiums paid for call options, as well as the difference between the fixed price or option strike price and the spot market price. There is often a failure to see the cost of options as an insurance premium, as well as to consider a fixed price as a rate stabilization tool. Further, what's missing is
more analysis of the potential avoided cost. Additional scenario analysis would demonstrate the risk of what could have occurred as well as estimate the potential price exposures avoided as a result of hedging.

Additionally, some stakeholders raise the concept of "least cost" in hedging program critiques. Care must be exercised when applying the least-cost principle to hedging, which presents trade-offs in risk, reward, and costs, depending upon the hedging instrument. Using the analogy of insurance, it is possible to buy an inexpensive policy with a low premium, but this is usually accomplished by increasing the deductible, placing a cap on the total payout, or carving out conditions under which benefits aren't paid. Additionally, different hedging strategies yield different benefits, depending on market price direction. For example, if a utility is purchasing energy in a rising-price market, a fixed price purchase might be optimal as there is no option payment incurred and the coverage starts immediately. In a range-bound market, a costless collar might be the lowest cost of insurance, and in a declining market, a cap at a relatively high strike might be the most attractive form of hedge protection.

The Shale Gas Factor

A review of comments filed by commission staff and other stakeholders shows that shale gas development is repeatedly referred to as a "game changing" technology. Shale gas producers access prolific geological deposits of reserves for production at relatively low costs, which has led to significantly dampened price volatility and lower market prices.

While the emergence of shale gas production is generally well-known by intervenors and regulators, the broader market dynamics are less well understood. Equally important is the fact that new pipeline infrastructure has served to deliver shale gas supplies into what historically have been transportation-constrained end markets, thereby changing traditional basis-pricing relationships and further easing price volatility. Additionally, new LNG import facilities and expansions in natural gas storage capacity in recent years have contributed to expanded supply capacity. These supply and capacity additions have occurred at the same time that demand has declined. On the demand side, increasing energy efficiency measures and declining demand resulting from weak economic conditions have dampened consumption.

However, history repeatedly has shown that commodity market conditions are never stagnant, and that markets often correct as supply and demand factors re-balance. The recent 24 months of price declines have lulled many stakeholders into believing that low gas prices are now the norm, but market conditions will change at some point. The question is when, how quickly, and to what degree? If we have learned anything from the past, it is that we cannot predict the future with certainty. In the future, changing supply-demand factors might turn market prices in the other direction.

Utilities will want to be prepared before a market shift occurs. On the supply front, there might be environmental regulation that slows shale gas production, additional compliance requirements that increase shale gas production costs, or technical factors that reduce the projected size of economical reserves. Natural gas demand might increase due to stymied nuclear plant development, rising coal plant operating costs, or closures of coal plants as a result of environmental compliance. New demand could result from economic recovery, LNG exports, or new natural gas and electric vehicle use. A combination of these factors could cause the North American gas supply-demand balance to materially shift, bringing about increases in market prices and volatility.

As market prices have dropped, many stakeholders are encouraging utilities to adapt their hedging practices to the current market supply and pricing paradigm. Some have suggested utility hedging be reduced until such time as gas market prices show some sign of rallying. Others are taking a more proactive stance, encouraging longer-dated hedging and new hedging program design.

Two commissions that recently have suspended hedging activities are the Public Utilities Commission of Nevada (December 2010), with respect to Nevada Power, and the British Columbia Utilities Commission (July 2011), in regard to FortisBC. The commissions didn't disallow previously executed hedge transactions, and they left existing hedges in place; the decisions applied to future hedging activity.

In its Dec. 16, 2010 order (Docket No. 10-09003), the Nevada PUC approved a stipulation that included the requirement that Nevada Power not proceed with any additional financial gas hedges. However, the utility was told it should continue reviewing natural gas hedging in light of prevailing market fundamentals and conditions.[4] More recently, on July 22, 2011, the British Columbia Utilities Commission rejected FortisBC's "Price Risk Management Plan." In the order, the Commission Panel wrote: "in light of the recent exploitation of shale gas, the likelihood for more stable natural gas prices is significantly greater and the risk of dramatically higher natural gas prices, excepting short periods of price disconnects, is significantly lower than it has been in many years."[5] Further, the panel suggested that hedging was not the best way to deal with the potential for price increases, but commented that if there were a change in market conditions, they would be willing to consider proposals to mitigate price risks for customers. They concluded by saying that the performance of the utility's "Price Risk Management Plan" over the last 10 years did not convince them that continuation of the program was in the ratepayers' interest.

Measuring Prudence

Hedging programs are undergoing a greater degree of regulatory scrutiny. In some instances, hedging programs have been scrutinized and continued without modification, while in other cases, hedging programs have been targeted for additional review.

In spring 2009, the Colorado Public Utilities Commission commented on testimony filed by commission staff, which criticized gas hedging by Xcel's subsidiary, Public Service Company of Colorado. The staff had conducted a quantitative analysis to determine that during the period following Hurricane Katrina (2005-2006), the utility's hedges were close to breaking even, *i.e.*, the premium paid for hedging nearly equaled the benefits it provided over spot market prices. But a break-even analysis of the hedging costs compared to spot market prices for the period 2005 to 2008 illustrated that the utility only regained approximately one third of every dollar spent on hedging. Ultimately, in its order, the commission supported the administrative law judge's position that the utility's hedging program should not be suspended. In his recommended decision, the judge wrote, "Preapproved elements of the [hedging] plan avoid hindsight evaluation of each program. Simply stated, [the plan] is to be evaluated based upon information available at the time, not in terms of whether the plan 'beat the market.' To the extent Public Service implements such a plan, as approved, the associated hedging costs should not be subject to disallowance in any subsequent gas cost prudence review proceedings."[6]

In another example, a commission decided to open a utility's hedging program to further review. In May 2011, in response to PacifiCorp's rate filing for Rocky Mountain Power, the Utah Industrial Energy Consumers filed direct testimony asking the Utah Public Service Commission to disallow $19.7 million in revenue requirements related to what the group called "imprudent hedging practices" by the utility. Rocky Mountain Power's hedging program layered-in hedges 48 months into the future, hedging nearly 100 percent of its open commodity price risk. In the industrial group's testimony, it commented that the utility's hedging program wasn't adjusted to account for changes in market conditions and the expanding supply of natural gas through shale gas production.[7] Hence, the industrial group suggested the utility was imprudent to hedge such a large percentage of its open positions and should have reduced its fixed-price hedges, to leave open one-third of its portfolio to spot market pricing.

In July 2011, a stipulation was filed with the Utah PSC where the parties agreed to a collaborative process to review possible changes to the company's hedging practices. As part of the stipulation, it was agreed that the utility's past hedges wouldn't be disallowed, but that the utility would implement any changes that result from the collaborative process or commission order. Issues addressed in the collaborative process included: a new maximum hedge volume percentage limit or range; risk tolerance bands based on time-to-expiry value-at-risk (TEVaR) or value-at-risk (VaR) limits; position limits; a process for review of hedging transactions outside of accepted guidelines, including natural gas reserves or storage; liquidity, transparency, and other risks of different hedging tools such as financial swaps, fixed-price physical forward contracts, and options; a semi-annual confidential report on hedging status; and coordination and implementation issues relating to the inclusion of financial swap transactions in Rocky Mountain Power's energy balancing account.[8] The stipulation was approved in a commission order on Sept. 13, 2011, and PacifiCorp and the other stakeholders were expected to complete discussions by January 2012.

In February 2011, the South Carolina Office of Regulatory Staff (ORS) requested suspension of the hedging programs of South Carolina Electric and Gas (SCE&G) and Piedmont Natural Gas. The ORS commented that the hedging costs incurred by the utilities might be appropriate for markets where there is significant price volatility, but were not appropriate for more stable natural gas market conditions. According to the ORS, SCE&G's hedging program cost customers more than $50 million since 2006, and Piedmont's program cost over $37 million since 2002.[9] This request for suspension was later withdrawn in July 2011, and it was determined that the utilities and the ORS would address the prudence of the hedging activities in each of the companies' respective annual purchased gas adjustment (PGA) proceedings.[10]

In SCE&G's PGA proceeding, the ORS evaluated the company's hedging program and affirmed its previous recommendation that the hedging program should be suspended. SCE&G agreed to immediately suspend all hedging until the commission directs it to recommence. The agreement anticipates that changing market conditions—*e.g.*, environmental restrictions on shale gas production—could warrant a resumption of hedging.[11] Conversely, Piedmont's hedging program was approved in its PGA proceeding with the removal of its previously established minimum hedging requirement of 22.5 percent. Although Piedmont's gas purchasing and hedging activities were deemed to be prudent, there was disagreement on whether gas purchasing and hedging activities, pursuant to a commission-approved hedging program, should be subject to an after-the- fact prudence determination. The commission requested an *ex-parte* briefing on the issue of how to measure prudency in hedging programs.[12]

Strategic Adaptation

In some jurisdictions, regulators are modifying the hedging program horizon and limiting discretionary actions. In Delaware, Delmarva Power has a programmatic hedging program with periodic hedging at pre-determined intervals. In 2009, the utility reduced the tenor and the total volume of hedging. More recently, in response to Delmarva Power's "Gas Cost Rate" filing, a consultant for the commission staff proposed two alternative hedging strategies to enhance flexibility in the hedging framework and to provide a greater smoothing effect on gas price spikes.

The consultant recommended either lengthening the "hedging interval" beyond 18 months to take advantage of lower volatility in outer months; or implementing dollar cost averaging,[13] with fixed dollars allocated for hedges rather than fixed volumes, so that hedging volumes would increase in low-priced market environments and would decrease in higher-priced market environments. The consultant stated that dollar cost averaging results in lower gas costs when compared to a less- flexible, programmatic hedging strategy.[14] Although no changes were made to Delmarva Power's gas hedging program, the company agreed to review and discuss the staff consultant's recommendations for modification.[15]

In Michigan, intervenors in the Consumers Energy rate case proposed a range of changes to reduce the volume and tenor of hedging under the utility's fixed-price hedging program to address concerns that the utility was over-hedging with fixed-price purchases. In that proceeding, intervenors urged the commission to eliminate the "tiered" strategy, which provided for programmatic purchases of fixed price supply in accordance with monthly hedge targets, and suggested modifications to the company's "quartile" strategy, which it had employed in tandem with the tiered strategy, using historical pricing to determine the amount of forward market hedging. All parties proposed a reduction in annual hedging caps. The ALJ decision supported the company's proposed plan, but indicated that certain accelerated purchases under the tiered strategy would require justification by market conditions to be deemed prudent.[16] At this writing, a final decision in this proceeding was pending.

In California, parties to the electric utilities' procurement plan filings are discussing moving from fixed caps on hedging, as determined by the consumer rate tolerance (CRT) of 1 cent per kilowatt hour, to a restructured CRT that represents a percentage of the individual utility's system average rate. By moving to a percentage of the system average rate, the percent hedged under the CRT would remain constant and wouldn't fluctuate with rate changes.[17]

Locking-In for the Long-Term

The Public Utility Commission of Oregon approved a $250 million investment in reserves by its gas utility, Northwest Natural. The utility entered an agreement with Encana Oil & Gas (USA) to develop physical gas reserves expected to supply a portion of the utility customers' requirements over a period of about 30 years, with 8 to 10 percent of Northwest Natural's average annual requirements supplied through the arrangement. The Commission approved the utility's plan in April 2011, allowing the utility to recover the costs of gas produced and delivered, plus a rate-base return on investment through its annual PGA mechanism.[18]

In Colorado, the *Clean Air - Clean Jobs Act* of 2010 (HB 10-1365), included a legislative provision to facilitate fuel-switching from coal to natural gas, while protecting ratepayers from volatility in prices. The provision provides regulatory certainty that utilities will be allowed full cost recovery, without risk of future disallowance, for commission-approved, long-term gas contracts—of between three and 20 years in duration—entered into pursuant to the act.[19] To that end, Public Service Company of Colorado and Anadarko entered a 10-year, fixed-price gas supply agreement, subject to annual price escalations, that is projected to result in savings to ratepayers of approximately $97 million, when compared to forecast gas costs without the contract.[20]

Black Hills Energy of Colorado has incorporated a long-term hedging strategy into its "Gas Mitigation Plan." The plan provides for hedging between 50 and 70 percent of its gas requirements under normal conditions, with the remaining gas requirements purchased in the monthly or daily spot market. Of the hedged volumes, half are comprised of fixed-price swaps phased in over three separate terms: three years, five years, and seven years. The long-term hedges, once fully phased- in, will represent approximately half of the company's normal annual volume requirements. Another

20 percent of the gas supply requirements are hedged using call options in a short-term hedging strategy for the upcoming year.[21]

Commissions will continue to review their utilities' hedging plans in a critical light, and it will be necessary for utilities to work in collaboration with stakeholders to consider adaptations to hedging plans that respond to new market conditions and that protect customers in the event of rising gas and power prices.

Window of Opportunity

Hedging objectives are an important part of the dialogue between commissions and utilities, and avoided costs need to be considered in developing a hedging program. "Hedging" can mean different things to different parties. Therefore, an important first step is to obtain broad consensus about the objectives of the utility's hedging program. By way of simple example, one objective could be that hedging is intended to protect customers against price spikes during certain high usage seasons, while another objective might be to protect customers against rising price trends that could occur over an extended period of time.

One benefit arising from the increased focus on utility hedging is that regulators and stakeholders have grown increasingly sophisticated about commodity markets and hedging, and some might support more complex programs in the future. However, the more discretionary a program design, the more critical decisional documentation and transparent processes become. Further, there must be rigor and consistency in how hedging is adjusted in different market price environments. It will be important in the design and approval stage that the hedging program has clear triggers for when hedging decisions will be executed. During the implementation stage, it will be important for utilities to document information that was known to them at the time hedges were transacted to demonstrate that reasonable actions were taken, consistent with the program design.

It is somewhat ironic that in today's market, as the price of hedging has declined, stakeholder support for hedging has waned. The low-price and low market-volatility environment introduces opportunities to execute hedges at historically attractive price levels. If utilities were to abstain from hedging until volatility increased and market prices rose, the cost of hedging would increase to the point where hedging could be deemed by regulators to be too costly for ratepayers.

In jurisdictions where intervenors and perhaps regulators might be reluctant to support an expansive hedging program at current lower market prices, utilities should use a collaborative process to garner support. The first objectives would be to improve stakeholders' understanding of the supply-demand market fundamentals that have contributed to current lower prices, and to explain future trends and events that could move market prices upward. A better understanding of market drivers and how prices could potentially change will help stakeholders appreciate the utility's need to be ready with hedging strategies to protect customers from rising wholesale market prices.

The second objective would be to engage stakeholders in a dialogue about how the utility's current hedging program was developed, and to listen to stakeholders' concerns. Working collaboratively, it is possible for all the parties to bring a fresh perspective to the hedging program and consider how it might be adapted under varied market conditions. Such efforts will yield the greatest benefit for utilities and their customers if they happen before supply-demand conditions materially change market prices, and the current window of opportunity closes.

Endnotes:

1. National Regulatory Research Institute, *NRRI Services: Survey on State Commission and Local Gas Distribution Company Actions in Addressing High Natural Gas Prices*, (July 3, 2008).

2. Bruce McDowell, *AGA Rate Inquiry: Regulatory Hedging Policies*, American Gas Association, (Fall 2009).

3. In a recent commission order (Docket No. UE 228), the Public Utility Commission of Oregon penalized Portland General Electric (PGE) for failure in 2007 to document the reasons for executing 2012 gas hedges. In its decision, the Commission noted its 2002 order (in Docket No. UE 139) in which the commission disallowed costs associated with certain of PGE's forward power purchases citing the company's failure to provide evidence regarding price trends or internal company market analyses that might have supported the reasonableness of the company's decisions. In its decision in UE 228, the commission reduced the utility's 2012 net variable power costs forecast by $2.6 million "to ensure management's future compliance" with commission orders. The penalty was calculated as the monetary equivalent of a one-year, 10-basis-point reduction in PGE's authorized return on equity. Public Utility Commission of Oregon, Docket No. UE 228, *2012 Annual Power Cost Update Tariff*, (Nov. 2, 2011).

4. Public Utilities Commission of Nevada, Docket No. 10-09003, *Application of NV Power Co d/b/a NV Energy for Approval of its Energy Supply Plan Update for 2011-2012*, Order (Dec. 16, 2010) and Stipulation (Nov. 9, 2010). Note, in September 2011, Nevada Power submitted a proposal to engage in new hedging, using out-of-the-money call options in its filing to the Public Utilities Commission of Nevada, *Application of Nevada Power Company d/b/a NV Energy for Approval of its Energy Supply Plan Update for 2012*, Docket No. 11-09003, (Sept. 1, 2011). However, in its draft order in the same docket, dated Dec. 14, 2011, the commission rejected NV Energy's hedging proposal and ordered NV Energy to continue the existing commission-approved hedging strategy described in the stipulation that the commission approved in Docket No. 10-09003 on Nov. 9, 2010, without exception.

5. British Columbia Utilities Commission, Order Number 6-120-11, *Application by Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. (collectively Terasen Gas) (now FortisBC Energy Inc. and FortisBC Energy (Vancouver) Inc.) for Approval of the Price Risk Management Plan Effective April 2011-October 2014*, (July 12, 2011).

6. Public Utilities Commission of the State of Colorado, Docket No. 08A-095G, *In the Matter of the Application of Public Service Company of Colorado for Authorization to Continue in Effect, On a Permanent Basis, Its Monthly Gas Cost Adjustment Tariffs, With Modifications to provide For Symmetrical Interest on Deferred Balanced of Over- And Under-Recovered Gas Costs, and to Extend For an Additional Four-Year Period the Current Procedures for Seeking and Obtaining Authorization to Implement Annual Gas Price Volatility Mitigation Plans for Its Gas Sales Customers*, (March 2, 2009).

7. Public Service Commission of Utah, Docket No. 10-035-124, Direct Testimony of J. Robert Malko, Utah Industrial Energy Consumers, *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, (May 26, 2011).

8. Public Service Commission of Utah, *Rocky Mountain Power Settlement Stipulation, (July 28, 2011) and report and order, Rocky Mountain Power 2011 General Rate Case*, Docket Nos. 10-035-124, 09-035-15, 10-035-14, 11-035-46 and 11-035-47, (Sept. 13, 2011).

9. South Carolina Office of Regulatory Staff, *Letter Re.: Request for Suspension of SCE&G and Piedmont Gas Hedging Programs*, Docket No. 2011-82-G, (Feb. 24, 2011).

10. Public Service Commission of South Carolina, Commission Directive, Docket No. 2011-82-G, Order 2011-402, (July 13, 2011).

11. Public Service Commission of South Carolina, Settlement Agreement, *IN RE: Annual Review of Purchased Gas Adjustment and Gas Purchasing Policies of South Carolina Electric & Gas Company*, Docket No. 2011-5-G, (Nov. 2, 2011).

12. Public Service Commission of South Carolina, Order Ruling On Purchased Gas Adjustment And Gas Purchasing Policies, *IN RE.: Annual Review of Purchased Gas Adjustment and Gas Purchasing Policies of Piedmont Natural Gas*, Docket No. 2011-4-G – Order No. 2011-580, (Aug. 17, 2011).

13. Dollar cost averaging is the technique of hedging a fixed dollar amount of a particular commodity on a regular schedule, regardless of the contract price. More contracts are purchased when prices are low, and fewer contracts are purchased when prices are high.

14. Public Service Commission of Delaware, PSC Docket No. 010-295F, Direct Testimony of Richard W. Lelash on behalf of the Staff of the Delaware Public Service Commission, *In the Matter of the Application of Delmarva Power & Light Company for Approval of Modifications to Its Gas Cost Rates*, (Feb. 10, 2011).

15. Public Service Commission of Delaware, Order No. 8061, *In the Matter of the Application of Delmarva Power & Light Company for Approval of Modifications to Its Gas Cost Rates* (Filed Aug. 31, 2010), PSC Docket No. 010-295F, (Oct. 18, 2011).

16. Michigan Public Service Commission, Case No. U-16485, Notice of Proposal for Decision, ALJ Sharon L. Feldman, *In the Matter of the Application of Consumers Energy Company for Approval of a Gas Cost Recovery Plan and Authorization of Gas Cost Recovery Factors For the 12-Month Period April 2011- March 2012*, (Sept. 12, 2011).

17. California Public Utilities Commission, Rulemaking 10-05-006, *Proposed Decision Approving Modified Bundled Procurement Plans*, Proposed Decision of ALJ Peter Allen, (Nov. 10, 2011).

18. Northwest Natural, Securities and Exchange Commission, 10-Q filing (First Quarter 2011).

19. See Colorado General Assembly H.B. 10-1365, Section 40-3.2-206. Part 4 (signed into law April 19, 2010).

20. *Statement of Position of Public Service Company of Colorado*, in Docket No. 10M-245E, at 72, (Nov. 29, 2010)

21. Direct Testimony of Trent Cozad, Docket No. 11A-580E before the Colorado Public Utility Commission *(Re: Gas Mitigation Plan)*, pp.3-7.

Media:

Source URL: http://www.fortnightly.com/fortnightly/2012/02/hedging-under-scrutiny

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 160001-EI DATED: September 23, 2016

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that the testimony of Mark Anthony Cicchetti on behalf of the staff of the Florida Public Service Commission was electronically filed with the Office of Commission Clerk, Florida Public Service Commission, and copies were furnished to the following, by electronic mail, on this 23rd day of September, 2016.

John Butler/Maria Jose Moncada
Florida Power & Light Company
700 Universe Blvd. (LAW/JB)
Juno Beach, FL 33408
John.Butler@fpl.com
Maria.Moncada@fpl.com

Ken Hoffman
Florida Power & Light Company
215 S. Monroe Street, Suite 810
Tallahassee, Florida 32301-1858
Ken.Hoffman@fpl.com

James Beasley./J. Jeffry Wahlen/
Ashley M. Daniels
Ausley & McMullen
Post Office Box 391
Tallahassee, Florida 32302
jbeasley@ausley.com
jwahlen@ausley.com
adaniels@ausley.com

Ms. Paula K. Brown
Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601
regdept@tecoenergy.com

Matthew Bernier
106 East College Avenue
Suite 800
Tallahassee, Florida 32301
Matthew.bernier@duke-energy.com

Dianne M. Triplett
299 First Avenue North
St. Petersburg, Florida 33701
Diane.triplett@duke-energy.com

Jon C. Moyle, Jr.
Moyle Law Firm, P.A.
118 North Gadsden Street
Tallahassee, FL 32301
jmoyle@moylelaw.com

Jeffrey A. Stone/Russell A. Badders/
Steven R. Griffin
Beggs & Lane
Post Office Box 12950
Pensacola, Florida 32591-2950
jas@beggslane.com
rab@beggslane.com
srg@beggslane.com

Robert L. McGee
Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0780
rlmcgee@southernco.com

J.R. Kelly/Patricia A. Christensen/Charles J. Rehwinkel/Erik L. Sayler/John J. Truitt
Office of Public Counsel
111 W. Madison Street, Room 812
Tallahassee, Florida 32399
Kelly.jr@leg.state.fl.us
Christensen.patty@leg.state.fl.us
Rehwinkel.charles@leg.state.fl.us
Sayler.erik@leg.state.fl.us
Truitt.John@leg.state.fl.us

Beth Keating
Gunster, Yoakley & Stewart, P.A.
215 South Monroe Street, Suite 601
Tallahassee, Florida 32301
bkeating@gunster.com

Mike Cassel
Florida Public Utilities Company
1750 S. 14th Street, Suite 200
Fernandina Beach, Florida 32034
mcassel@fpuc.com

James W. Brew/Laura A. Wynn
Stone Mattheis Xenopoulos & Brew, P.C.
1025 Thomas Jefferson Street, NW
Eighth Floor, West Tower
Washington, DC 20007-5201
jbrew@smxblaw.com
law@smxblaw.com

Robert Scheffel Wright/John T. LaVia, III
Gardner Bist Wiener Wadsworth Bowden Bush Dee LaVia & Wright, P.A.
1300 Thomaswood Drive
Tallahassee, Florida 32308
schef@gbwlegal.com
jlavia@gbwlegal.com

/s/ Suzanne Brownless
SUZANNE BROWNLESS
Senior Attorney, Office of the General Counsel

FLORIDA PUBLIC SERVICE COMMISSION
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
(850) 413-6199
sbrownle@psc.state.fl.us