Exhibit No.:	______________
Issue(s)	FAC
Witness/Type of Exhibit:	Hyneman/Direct
Sponsoring Party:	Public Counsel
Case No.:	EO-2017-0065

DIRECT TESTIMONY

OF

CHARLES R. HYNEMAN

Submitted on Behalf of the Office of the Public Counsel

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. EO-2017-0065

May 19, 2017

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Sixth Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of The Empire District Electric Company	)))))	Case No. EO-2017-0065

AFFIDAVIT OF CHARLES R. HYNEMAN

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Charles R. Hyneman, of lawful age and being first duly sworn, deposes and states:

1. My name is Charles R. Hyneman. I am the Chief Public Utility Accountant for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my direct testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

CRH

Charles R. Hyneman, C.P.A.
Chief Public Utility Accountant

Subscribed and sworn to me this 19th day of May 2017.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

JERENE A. BUCKMAN
My Commission Expires
August 23, 2017
Cole County
Commission #13754037

Jerene A Buckman

Jerene A. Buckman
Notary Public

My Commission expires August 23, 2017.

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DIRECT TESTIMONY

OF

CHARLES R. HYNEMAN
THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. EO-2017-0065

INTRODUCTION

Q. Please state your name and business address.

A. Charles R. Hyneman, PO Box 2230, Jefferson City, Missouri 65102.

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

A. I am employed by the Missouri Office of the Public Counsel ("OPC") as the Chief Public Utility Accountant.

Q. Please describe your educational background.

A. I earned a Master of Business Administration from the University of Missouri - Columbia, and a Bachelor of Science degree in Accounting and Business Administration from Indiana State University at Terre Haute, Indiana.

Q. Please describe your professional work experience.

A. I was a regulatory auditor of the Missouri Public Service Commission ("Commission") Staff ("Staff") from April 1993 to December 2015. During this period I held various positions in the Staff's Auditing Department, based in the Kansas City, Missouri Office. In this capacity I performed, supervised, and coordinated regulatory auditing work including utility rate case audits, infrastructure system replacement surcharge ("ISRS") reviews, merger and acquisition audits, fuel adjustment clause ("FAC") audits and prudence audits and reviews of major utility construction projects. I joined the OPC as Chief Public Utility Accountant in December 2015.

Q. Are you a Certified Public Accountant ("CPA") licensed in the state of Missouri?

A. Yes. I am a licensed CPA and member of the American Institute of Certified Public Accountants ("AICPA").

Q. Describe the background of this case.

A. On September 6, 2016, the Commission's Staff filed notice that it started its prudence audit of the fuel adjustment clause ("FAC") established for The Empire District Electric Company ("Empire"). Staff's FAC prudence audit period was March 1, 2015, through August 31, 2016 ("FAC audit period"). On February 28, 2017, Staff submitted its Prudence Audit Report. Staff identified no evidence of imprudence on the part of Empire.

OPC conducted a limited audit of Empire's fuel cost during this FAC audit period. OPC's prudence audit focused on Empire's natural gas fuel hedging activities. OPC witness John Riley provides in his direct testimony the basis for OPC's conclusion that Empire's hedging activities were imprudent and that material losses were incurred as a result of outdated and overly-rigid hedging policies. Empire's hedging policies date back to 2001, well before the major changes in the natural gas market which occurred in the 2009 time frame.

Q. What is the purpose of your direct testimony?

A. OPC is recommending that the Commission find Empire's hedging activities that led to significant hedging costs in this FAC audit period to be imprudent. OPC recommends the Commission also find that the hedging costs incurred as a result of Empire's imprudent hedging policies be deemed imprudent and ordered not to be borne by Empire's ratepayers but charged to Empire's shareholders.

My direct testimony will provide and describe the specific evidence necessary for the OPC to overcome its burden to raise "serious doubt" about the prudence of Empire's employment of its natural gas financial and physical hedging strategies as contained in its Risk

Management Plan ("RMP"). OPC witness John Riley will provide additional evidence in his direct testimony to support OPC's findings and conclusion of Empire's imprudence.

Q. Have you previously performed audits of regulated electric utility hedging practices?

A. Yes. I was the Staff auditor primarily responsible for the audit of Aquila, Inc.'s (now KCP&L Greater Missouri Operations Company or "GMO") natural gas expense and natural gas hedging activities in Aquila's 2005 and 2007 Missouri rate cases. I performed audits and reviews of Kansas City Power & Light Company's ("KCPL") hedging activities in several of its rate cases filed during the period 2006 through 2014. I also participated in the Staff's EO-2011-0390 prudence audit of GMO's hedging program and GMO's accounting for its hedging program. As the Chief Regulatory Accountant of the OPC, I participated in the audits of Empire, KCPL, and GMO's hedging practices in each of these utilities' 2016 rate cases. Finally, I participated as a member of Staff in the Commission's EW-2013-0101 investigatory docket. In this docket, the Commission ordered Staff to review the hedging policies and procedures of Missouri's electric utilities "to assist the utilities with developing effective hedging programs that serve the public interest by mitigating the rising costs of fuel."

PRUDENCE STANDARD

Q. What is the Commission's standard on rate recovery of Empire's FAC costs?

A. The Commission's primary standard for the recoverability of Empire's hedging costs during the FAC audit period is that all charges made by Empire must be just and reasonable. In its Order Approving Stipulation and Agreement in ER-2016-0023, the Commission stated "when seeking to increase the rates it charges its customers, Empire has the burden of proof to show by a preponderance of the evidence that increased rates are just and reasonable."

Despite this burden of proof placed on utilities, previous Commissions have ruled that when a party challenges the prudence of a utility cost, that challenge brings into effect the prudence standard. As will be described below in more detail, the Commission's prudence standard places the initial burden on the party challenging a utility's cost to raise "serious doubt" concerning the prudence of the cost. The Commission explained this standard in its June 28, 2007 Report and Order in Case No. GR-2004-0273, In the Matter of the PGA Filing for Laclede Gas Company:

> It is not, however, sufficient to state that Laclede, as the gas corporation, has the burden of proving that its gas costs are just and reasonable. The fact that Staff is challenging the prudence of incurring some of those costs brings into effect an additional standard, the prudence standard.
> The standard adopted by the Commission recognizes that a utility's costs are presumed to be prudently incurred, and that a utility need not demonstrate in its case-in-chief that all expenditures are prudent. "However, where some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling those doubts and proving the questioned expenditures to have been prudent."(Footnotes omitted)

Q. Is this FAC prudence audit case directly associated with an increase in Empire's electric utility rates?

A. Yes. This prudence audit is associated with Empire's increase in its FAC rates. One of the disconnects with mechanisms such as the FAC that allow for changes in rates between rate cases is that there is no opportunity for OPC, Staff or any other party to review the costs for prudence before rates are increased. In order to remedy this disconnect, Section 386.266.4.(4) requires a prudence review be conducted no less frequently that every 18 months.

Q. Did Empire through its FAC rate adjustment mechanism increase the rates it charged its customers as a result of its hedging losses incurred during this FAC audit period?

A. Yes. Empire billed through its FAC approximately $8.3 million in financial hedging losses (losses from the purchase of NYMEX futures contracts) and $4.8 million in physical (bilateral contracts) hedging losses for a total of $13.1 million in natural gas hedging losses. The application of outdated and inflexible hedging plans and strategies is imprudent and the $13.1 million of hedging costs incurred during this FAC audit period are not just and reasonable but are imprudent and should be returned, with interest, to Empire's regulated electric utility ratepayers.

Q. Did Staff auditors address the issue of Empire's prudence in Staff's Prudence Audit Report?

A. Yes. Staff addressed the issue of prudence at page 1 and page 3 of its Prudence Audit Report. Staff summarized the Commission's prudence standard by quoting a Western District Court of Appeals Opinion, *State ex rel. Associated Natural Gas Co. v. Public Service Commission* (954 S.W.2d 520, 528-529 (Mo. App. W.D. 1997)

Q. In what case did the Commission develop its policy and standards for reviewing utility prudence issues?

A. The Commission developed its policy and standards for reviewing utility prudence issues in Case Nos. EO-85-17 and ER-85-160, regarding Union Electric Company's ("UE") Callaway Nuclear Plant prudence issues. The Commission has continued to apply these same prudence standards since 1985. The Commission's prudence standards are described in the following quotes from its Report and Order in the 1985 Union Electric ("1985 UE Prudence Order") cases:

> Based on the foregoing considerations, the Commission determines that UE has the burden of proving the reasonableness of the costs associated with Callaway. The Commission further determines that reasonableness should be judged using the standard of prudence. However, prudence requires further elucidation.
>
> It is sometimes contended that management prudence is presumed. With respect to the question of the presumption of management prudence, the Commission agrees with the following conclusions of the Washington D.C. Circuit Court of Appeals:

The Federal Power Act imposes on the Company the "burden of proof to show that the increased rate or charge is just and reasonable." 16 U.S.C. '824d(e). Edison relies on Supreme Court precedent for the proposition that a utility's cost are presumed to be prudently incurred. See Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri Pub. Serv. Comm., 262 U.S. 276, 289 n.1 (1923).

However, the presumption does not survive "a showing of inefficiency or improvidence." West Ohio Gas Co. v. Public Utilities Comm., 294 U.S. 63, 55 S.Ct. 316, 79 L.Ed. 761 (1935); see 1 A.L.G. Priest, Principles of Public Utility Regulation 50-51 (1969).

As the Commission has explained, "utilities seeking a rate increase are not required to demonstrate in their cases-in-chief that all expenditures were prudent. . . However, where some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent." Opinion No. 86, Minnesota Power & Light Co. Opinion and Order on Rate [*26] Increase Filing, Docket No. ER76-827, at 14, 20 Fed. Power Service, 5-874, 5-887 (June 24, 1980) (footnotes omitted). Anaheim, Riverside, etc. v. F.E.R.C., 669 F2d 779 (D.C. Cir. 1981).

In the Commission's opinion, the existence of $2 billion in cost overruns raises doubts as to prudence in this case. Therefore, UE has the burden of proof regarding prudence.

The Commission determines that the appropriate standard to be used in this case was enunciated by the New York Public Service Commission in Re: Consolidated Edison Company of New York, Inc., 45 P.U.R., 4th, 1982. In that case at page 331, the New York Commission rejected an earlier "rational basis" standard in favor of a reasonable care standard:

More recently, and in cases more directly on point, we have articulated the standard against which a utility's conduct in circumstances such as these should be measured as follows:

". . . the company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively

> rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company. Case 27123, Re: Consolidated Edison Company of New York, Inc., Opinion 79-1, January 16, 1979."
>
> In reviewing UE's management of the Callaway project, the Commission will not rely on hindsight. The Commission will assess management decisions at the time they are made and ask the question, "Given all the surrounding circumstances existing at the time, did management use due diligence to address all relevant factors and information known or available to it when it assessed the situation?"
>
> In accepting a reasonable care standard, the Commission does not adopt a standard of perfection. Perfection relies on hindsight. Under a reasonableness standard relevant factors to consider are the manner and timeliness in which problems were recognized and addressed. Perfection would require a trouble-free project.
>
> Public utility regulation is based on the theory that a public utility is a natural monopoly since only one firm can efficiently serve a given market. To avoid monopoly pricing the state regulates the public utility to ensure reasonable rates. Thus, regulation is intended to serve as a surrogate for competition. The public utility is given a franchise to serve within a given area as a state-sanctioned monopoly and in return accepts the duty to serve all customers.
>
> Because of the grave financial consequences which could accrue to captive monopoly ratepayers if a utility's investments were to prove uneconomic, the Commission determines that a standard of reasonable care requiring due diligence is appropriate for determining whether UE's actions during the course of the project were prudent.

Q. Has OPC applied these very prudence standards to its prudence audit of Empire's natural gas hedging policies and costs?

A. Yes. As did the Commission in its 1985 UE Prudence Order, OPC applied an audit standard of "reasonable care" requiring "due diligence" on the part of Empire's management. OPC's prudence audit of Empire's hedging activities was based on answering the following question: Given all the surrounding circumstances existing at the time, did Empire's management use due diligence to address all relevant factors and information known or available to it when it engaged in natural gas hedging transactions that resulted in losses in this FAC audit period?

A major component of the Commission's prudence standard is that utility management's actions should not be evaluated based on the use of hindsight. OPC agrees and has not applied hindsight to its analysis of the prudence of Empire's actions. The Commission's policy on hindsight in prudence audits is widely accepted. Julie Ryan and Julie Lieberman, from the utility and energy consulting firm Concentric Energy Advisors, explained this standard in the February 2012 issue of Public Utilities Fortnightly.

> 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. [Hedging Under Scrutiny: Planning ahead in a low cost gas market", Julie Ryan and Julie Lieberman, Public Utilities Fortnightly, February 2012, p. 12].

EMPIRE'S HEDGING POLICIES

Q. Why did Empire create its natural gas hedging policies?

A. Empire created its natural gas hedging policies to lessen the impact of expense volatility and establish a more predictable basis for future rate cases. Empire described the reasons why it created its hedging strategies at page 160 of its *Empire Century of Service, Part - 5.* This document was found on Empire's website www.empiredistrict.com/About/History.

> Hedging Strategies
>
> Empire management continued to plan ahead by establishing prudent hedging strategies. Fuel and purchased power made up about 55% of the operating expenses. Fuel price volatility had major ramifications on both short-term and long-term purchasing strategies. In 2001, a hedging strategy was implemented for natural gas, which allowed

> use of both physical purchases and financial tools. Under this strategy, the company would hedge future natural gas requirements over time under a set of predetermined percentages. The aim was to lessen the impact of volatility in fuel and purchased power expenses and establish a more predictable basis for future rate proceedings.(emphasis added)

Q. Did Empire affirm the purpose of its hedging strategies in an application before the Kansas Corporation Commission ("KCC")?

A. Yes, at page 2, paragraph 4 of its March 30, 2006 Application before the KCC seeking KCC approval of its hedging policies Empire stated that it "uses its [Risk Management Policy] to mitigate the price volatility of the natural gas market and improve the predictability of its future energy costs."

Q. Did Empire advise the Commission in 2004 that it annually revises its hedging policies in response to "lessons learned" and changes in the natural gas market?

A. Yes. In his direct testimony in Case No. ER-2004-0570 Empire's then Vice President of Energy Supply, Mr. Brad Beecher, so advised the Commission. At page 8 line 21 of his direct testimony Mr. Beecher, who subsequently became Empire's President and Chief Executive Officer said:

> Empire originally enacted a Risk Management Policy ("RMP") in 2001 that establishes the approach and internal rules that Empire will use to manage specifically its power and natural gas commodity risk. The policy is revised approximately annually to reflect lessons learned and changes in markets and financial instruments. (emphasis added).

Q. Please comment on Mr. Beecher's testimony.

A. The policy as stated by Mr. Beecher of making annual revisions to the hedging policy to reflect lessons learned and changes in the natural gas market was a reasonable and prudent policy. If Empire would have actually followed this stated policy, it would be very likely that Empire would not have incurred material hedging losses in this FAC audit period and this issue of hedging imprudence would not be before the Commission.

However, despite what I view as a commitment to the Commission to prudently manage its hedging policy made by Mr. Beecher, Empire did not live up to this commitment and it made no changes to its strict and rigid hedging policy despite massive changes in the natural gas market in terms of prices and volatility. As will be described later, the changes in the natural gas market were so significant that the Commission's Staff recently recommended that another Missouri electric utility, KCP&L Greater Missouri Operations ("GMO"), suspend its natural gas hedging operations. Also, as far back as 2010, other state regulatory commissions and utility companies themselves were taking action to scale back on electric utility hedging activities.

Q. Does OPC consider Empire's decision not to follow-through on the commitment made by Mr. Beecher to modify Empire's hedging activities in response to changes in the natural gas market to be imprudent?

A. Yes. Empire's decision not to make any changes to its rigid and inflexible hedging policy and practices at or near the time of major changes in the natural gas market, is not a decision that reasonable and prudent utility managers would make.

Q. What evidence is there that Empire failed to live up to this commitment and revise its hedging policies "approximately annually" to reflect lessons learned and changes in markets and financial instruments?

A. At page 2 lines 5-10 of his May 13, 2016 surrebuttal testimony in Empire's last rate case, ER-2016-0023 (Empire exhibit 12), Blake Mertens, Empire's vice president – Energy Supply and Delivery Operations, described how Empire made no changes to its hedging policies (Risk Management Plan) from 2001 through at least May 2015.

> <u>Empire first implemented its Energy Risk Management Policy ("RMP") in 2001</u>. While slight modifications have been made

> throughout the years largely to update organizational or nomenclature changes, the most substantive of which was prior to the SPP IM going live to reflect changes in daily processes and reflect transmission congestion rights procurement practices, our natural gas hedging policy and practices have remained consistent. (emphasis added)

CHANGES IN THE NATURAL GAS MARKET

Q. Given your experience auditing electric utility hedging practices, are you very familiar with the changes in the natural gas market from 2009 to 2017?

A. Yes, I am.

Q. Describe the changes in the natural gas market starting in 2009 and contrast this market with the market that existed prior to 2009.

A. Starting in 2009 the natural gas market changed from a market characterized by high prices and high volatility to one that consistently reflects low prices and low volatility. Between 2008 and 2017 natural gas prices at the Henry Hub have averaged at or below $4/MMBtu in six of those eight years. In addition, natural gas prices never averaged higher than $4.39 per MMBtu in any year since 2008. Natural gas prices at the Henry Hub in Louisiana are the most recognized index or benchmark for natural gas prices in the United States.

In contrast, between 2003 through 2008, natural gas prices experienced high levels of volatility and high prices. Average annual natural gas prices during this period ranged from $5.49 to $8.86 per MMBtu. Monthly average Henry Hub natural gas prices as published by the Department of Energy's U.S. Energy Information Administration ("EIA") are shown below. The purpose of the EIA is to collect, analyze, and disseminate independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment.

Henry Hub Natural Gas Spot Price (Dollars per Million Btu)													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Avg**
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	$2.50
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	$2.09
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	$2.27
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	$4.31
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	$3.96
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	$3.37
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	$5.49
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	$5.90
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	$8.81
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	$6.75
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	$6.98
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	$8.86
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	$3.95
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	$4.39
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	$4.00
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	$2.75
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	$3.73
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	$4.39
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	$2.63
2016	$2.28	$1.99	$1.73	$1.92	$1.92	$2.59	$2.82	$2.82	$2.99	$2.98	$2.55	$3.59	$2.52
2017	$3.30	$2.85	$2.88	$3.10									$3.03
Source:	https://w w w .eia.gov/dnav/ng/hist/rngw hhdm.htm												

Q. Is the conclusion you reached, that there have been major changes in price and volatility in the natural gas market, shared by experts in the area of natural gas hedging for utilities?

A. Yes. Julie Ryan and Julie Lieberman co-authored an article in the February 2012 edition of Public Utilities Fortnightly entitled *Hedging Under Scrutiny: Planning Ahead in a Low Cost Gas Market"*. At the time this article was published, Ms. Ryan was a vice president and Julie Lieberman was a project manager with Concentric Energy Advisors ("Concentric").

Ms. Ryan had over 25 years of experience in the energy industry in the areas of strategy and management. She had been consulting since 2006, and prior to that she was a senior leader in utility, merchant power, and trading & marketing firms. She held two officer positions at Puget Sound Energy, first as Vice President Energy Portfolio Management and then Vice-President, Risk Management and Strategic Planning. Ms Ryan provided advisory services to clients in the areas of hedging and risk management. Most of her clients were utility clients, and she conducted audits of energy supply practices, reviewed hedging programs, and provided recommendations on how companies can adapt and improve their risk management programs.

Ms Lieberman was a financial and economic consultant with Concentric with over 25 years of experience in the energy industry. Her experience included: financial and economic consulting in the energy sector, risk management, asset valuation and modeling, wholesale and retail energy trading and operations, energy procurement and scheduling, hedging strategies, regulatory policy and compliance, utility ratemaking, due diligence and litigation support and analysis.

In the February 2012 edition of Public Utilities Fortnightly the authors described the changes in the natural gas market:

> 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.

Q. Did the authors of the February 12, 2012 Public Utilities Fortnightly article highlight the fact that as early as 2010 and 2011 regulatory commissions were taking action to reign in utility hedging programs?

A. Yes. The authors noted that as natural gas prices have dropped, stakeholders (consumer advocates, commission staffs and commissions) were encouraging utilities to modify hedging practices (scale back on hedging) in response to the changes in the natural gas market. Some commissions took action as far back as 2010. Since then, the issue of utilities continuing to incur hedging losses has been an issue with several state utility commissions. The article states:

> 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.
>
> 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."

Q. Can you provide an example of how a utility acted prudently in actions taken in response to the changes in the natural gas market in 2008-2009?

A. Yes. Colorado Utilities ("CU") is a municipal utility in Colorado Springs, Colorado. On its website (https://www.csu.org/Pages/nghedging-b.aspx) CU described the actions it took in 2010 and 2011 to first scale back and then suspend its hedging programs in response to the changes in the natural gas market. This document is attached as Schedule CRH-D-3 to this testimony.

The actions taken by CU, as described below, are prudent and reasonable responses to the sustained changes in the natural gas market. The specific actions taken by CU are the exact same actions that Empire, if acting prudently, would have taken prior to the time it purchased the hedges that resulted in the hedging costs in this FAC audit period.

CU described its prudent response to the changes in the natural gas market to its customers on its website in a question and answer format:

> **What has happened to natural gas prices in recent years?**
>
> After years of large wholesale price increases and dramatic volatility, prices dropped significantly in 2008. Prolonged, poor economic conditions and a fundamental supply increase from widespread use of horizontal drilling and formation fracturing technologies kept prices relatively low. Utilities has taken advantage of current lower prices on non-hedged supply and passed the lower costs on to customers.
>
> **Are we hedging now?**
>
> No. With market costs declining, we began a significant review of our hedging program in 2009, and in 2010 reduced volumes and lengths of hedges. With continuing apparent market stability, all hedging was suspended in 2011. The small amount of hedged supply still on the books will expire in 2013.
>
> **Will we hedge in the future if the market becomes more volatile, or prices rise significantly?**

> While natural gas prices have risen in the past year, prices have remained relatively stable and are predicted to stay relatively stable for the short to medium term. Utilities is reviewing a range of alternatives to manage future price volatility, including reinstating hedging. The Utilities Board will be engaged on decisions to implement such alternatives
>
> **In which years did Colorado Springs Utilities hedge for natural gas?**
>
> From 1997 to 2010, Colorado Spring Utilities hedged much of its anticipated natural gas volumes for three years into the future. While hedging ceased in 2011, forward fixed price positions were placed at the end of 2010 to hedge forecast gas sales into 2013.

Q. Due to the changes in the natural gas market are Empire's hedging costs necessary to serve Empire's Missouri retail customers?

A. No. My conclusion is based on my experience in other Commission cases associated with electric utility natural gas hedging and the analysis performed by OPC in this case. My conclusion is that given the current natural gas market Empire's natural gas hedging activities and the resulting hedging costs incurred are neither a reasonable nor a necessary cost of providing electric utility service for its ratepayers.

In 2001 when Empire created its hedging policies, there may have been a need to shield its ratepayers from highly volatile and very high natural gas prices. The problem is that the natural gas market has changed significantly since 2001 but Empire's hedging strategy has not.

Empire employs an old, outdated and highly rigid hedging policy in a new and completely changed natural gas market. Refusing to change its policies in response to these changes in the market, despite its commitment to do so, is without question, imprudent. This imprudent action on the part of Empire has resulted in harm to its ratepayers in the millions of dollars in unnecessary and unreasonable hedging costs that they have paid or are currently paying in utility rates through its FAC surcharge.

The FAC was designed to include only costs that are necessary to provide utility service. These hedging costs do not meet that requirement and the OPC asks the Commission to agree with this conclusion.

Q. Are there other facts that support OPC's conclusion that Empire's hedging cost incurred in its Missouri jurisdiction is not a necessary cost of providing electric utility service?

A. Yes. Empire provides electric utility service in the state of Kansas. However, the Kansas Commerce Commission ("KCC") has never allowed Empire to include hedging costs in its electric utility cost of service charged to Kansas ratepayers. This same KCC treatment also applies to Kansas City Power & Light Company ("KCPL"). The KCC has never allowed KCPL to recovery any natural gas hedging costs in its Kansas service territory, which is approximately 50 percent of KCPL's operations. Despite participating in several KCPL rate case audits since 2006 and being actively involved in KCPL's fuel and hedging operations, I have never seen one claim by KCPL that natural gas hedging costs were necessary to provide electric service to Kansas customers.

Q. Did KCPL recently agree to suspend its natural gas hedging operations?

A. Yes. KCPL, in its recent rate case, ER-2016-0285, agreed to suspend its natural gas hedging for its Missouri customers. Going forward, KCPL's Missouri customers will be treated in the same manner as KCPL's Kansas customers and not have to bear the burden on unnecessary natural gas hedging costs.

Q. Did Empire ask the KCC to approve its hedging policies for its Kansas customers?

A. Yes. On March 30, 2006, Empire filed an application before the KCC seeking approval of its hedging policies as outlined in its RMP. The KCC, on February 4, 2008, in Docket No. 06-EPDE-1048-HED, issued its Order Denying Application. This KCC docket is titled *In the Matter of the Application of The Empire District Electric Company*, *for Approval of its*

Docket No. 06-EPDE-1048-HED Existing Energy Risk Management Policy, Which Includes Empire's Natural Gas Hedging Program. The KCC included the following in its Findings and Conclusions

> III. FINDINGS AND CONCLUSIONS
>
> 7. The Commission concurs with Staff's Memorandum filed in this matter and its determination that Empire's gas hedging program is incompatible with hedging programs currently approved and in place with respect to other public utilities regulated by the Commission. Therefore, the Commission finds that Empire's Application should be dismissed.
>
> The Commission further concurs with Staffs additional recommendations that: (1) Empire will pass no gains, losses, or costs related to its financial hedging activities to Kansas ratepayers through its Energy Cost Adjustment (ECA) mechanism; and (2) No costs related to Empire's financial hedging activities will be included for rate determination in future proceedings before the Commission.

Q. Does the Commission's rule that governs electric utility FACs allow only costs that are necessary to serve the electric utility's Missouri retail customers?

A. Yes. This rule is 4 CSR 240-20.090 Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms. Section (1)(B)2.A. of this rule states that if off-system sales revenues are reflected in an FAC, fuel and purchased power costs reflect both "[t]he prudently incurred fuel and purchased power costs necessary to serve the electric utility's Missouri retail customers; and the prudently incurred fuel and purchased power costs associated with the electric utility's off-system sales."

This Commission rule established two standards for costs in an FAC. First, the costs must be "prudently incurred" and second, the costs must be "necessary" to serve customers. Empire's hedging costs incurred in the FAC audit period in this case do not meet either of these standards.

Q. Regardless of the outcome of this FAC case, do you believe that Empire should suspend its natural gas hedging activities until the natural gas market experiences significant price fluctuations as it did in the period 2000 through 2008?

A. Yes. As noted above for KCPL, while not directly related to the issue of imprudence in this audit period, it is significant that the Commission approved rate case Stipulations and Agreements in the KCPL and GMO 2016 rate cases that require KCPL and GMO to suspend their respective natural gas hedging activities on a going forward basis. In these agreements, OPC, Staff, KCPL and GMO all agreed that KCPL and GMO would suspend natural gas hedging activities unless and until there is a change in the natural gas market that requires the utilities to restart hedging activities.

As a result of these 2016 rate case natural gas hedging agreements, the facts now stand that KCPL does not hedge in Kansas, KCPL does not hedge in Missouri, GMO does not hedge in Missouri, and Empire does not hedge in Kansas. It is now time for Empire to stop hedging in Missouri.

"SERIOUS DOUBT" STANDARD

Q. Earlier you provided the Commission's prudence standards, including the standard placed on parties to raise "serious doubt" of the prudence of a utility expense. Has the Federal Energy Regulatory Commission ("FERC") very recently provided some guidance on how it applies the "serious doubt" prudence standard to utility expenses?

A. Yes. In paragraphs 100 and 101 of its Opinion No. 554, Docket Nos. ER09-1256-002, ER12-2708-003, *Order on Initial Decision* issued January 19, 2017, the FERC described how it applies this standard:

> 100. The regulated entity has the burden of proof to establish prudence. However, in order to ensure that rate cases are manageable, the Commission presumes that all expenditures are prudent so the utility need not justify in its case-in-chief the prudence of all of its costs.

> The Commission permits challenges to the prudence of individual expenditures when the Commission's filing requirements, policy, or precedent require otherwise, the Commission itself determines that the company must establish the prudence of an expenditure, or a party creates serious doubt as to the prudence of an expenditure."
>
> Serious doubt must be more than a "bare allegation of imprudence," but this threshold may not be so demanding that it effectively reverses the statutory burden of proof. We find no reason to distinguish between direct and circumstantial evidence in determining whether the challenging party has raised a serious question of the prudence of expenditure.
>
> 101. Once such serious doubt has been raised, the company has "the burden of dispelling these doubts and proving the questioned expenditure to have been prudent."This showing must meet the ordinary evidentiary standard of a preponderance of the evidence on the record. Since the parties have fully litigated the prudence issues, we will base our decision on whether a preponderance of the evidence demonstrates that PATH acted prudently. (footnotes omitted).

Q. In past cases, what factors have led the Commission to conclude that the "serious doubt" burden had been met?

A. In its Report and Order in Case Nos. EO-85-17 and ER-85-160 the Commission concluded that Union Electric's significant cost overruns associated with a construction project was sufficient to raise serious doubt about the prudence of Union Electric's expenditures. As a result the Commission found that the burden shifted to Union Electric to show that its expenditures were prudent.

Also, in its Report and Order in Case No. GR-2004-0273, the Commission found that Staff raised serious doubts about the prudence of Laclede's expenditures for the purchase of its natural gas supplies. The Staff showed that Laclede could have paid less for the gas supplies had it followed different natural gas purchasing practices. The Commission found that Staff successfully raised serious doubts about the prudence of Laclede's fuel purchasing practices and thus the burden shifted to Laclede to prove that its fuel costs were prudent.

Q. Given these two examples, do you believe that OPC has met the Commission's "serious doubt" standard?

A. Yes. Similar to the facts in the Union Electric case, Empire's Missouri jurisdictional FAC financial hedging losses of $8.3 million ($10.8 million total company) and $4.8 million Missouri jurisdictional physical hedging losses ($6.1 million total company) in this FAC audit period total $13.1 million on a Missouri jurisdictional basis ($16.9 total company).

Compared to a total natural gas commodity cost during this period, Empire has charged its ratepayers a 38.5% premium on every dollar it spends to purchase natural gas. In other words, for every dollar Empire customers reimburse Empire for its gas purchases, ratepayers have to pay an additional 39 cents for natural gas hedging losses. The sheer size of these hedging losses compare to the size of the Union Electric cost overruns on a relative materiality basis. This fact is sufficient by itself to raise serious doubt about the prudency of Empire's hedging practices. However, the facts and circumstances of the Laclede case, where the Commission found that the burden of "serious doubt" was met, also mirror this Empire case.

In the Laclede case the Commission found that Laclede could have paid less for the natural gas supplies it purchased had it followed different gas purchasing practices. The exact same facts exist in this case with Empire. Empire could have paid significantly less for its natural gas purchases had it suspended, or at least significantly scaled back, its natural gas hedging practices while experiencing a significantly stable, low priced natural gas market. Given the Commission's conclusion in the Laclede case that Staff met the burden of raising serious doubt of the prudence of Laclede's purchases, the Commission should find the same for OPC in this case.

STAFF'S POSITION ON ELECTRIC UTILITY HEDGING

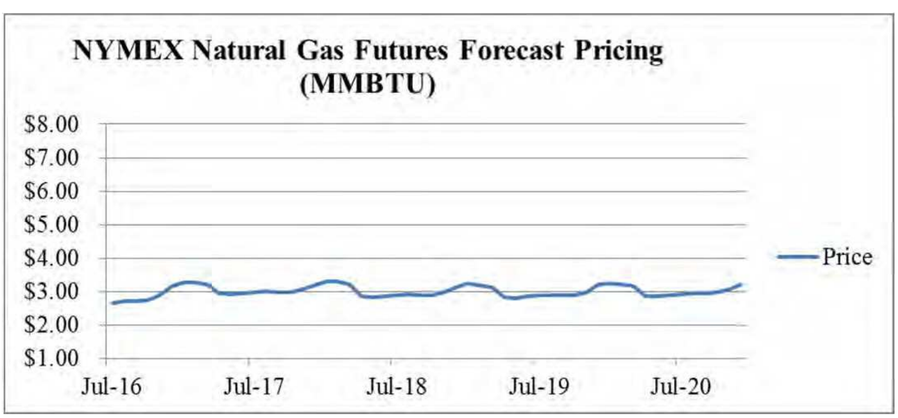
Q. On July 15, 2016 in Staff Report Revenue Requirement Cost of Service ("Staff Report") in Case No. ER-2016-0156, GMO's last rate case, did Staff address the issue of GMO's natural gas hedging activities?

A. Yes, Staff witness Dana E. Eaves sponsored Staff's recommendation that GMO should suspend its natural gas hedging activities due to changes in the natural gas market, including the implementation of the Southwest Power Pool's Integrated Marketplace ("IM") in 2014.

Q. Did Mr. Eaves address the fact that natural gas markets have been stable and are expected to remain stable?

A. Yes. Mr. Eaves provided the chart below at page 191 of the Staff Report. This chart reflects estimated future natural gas prices. He also described the past and projected stability in the natural gas market as follows:

> Natural gas prices have stabilized and are expected to remain stable. While consumption of natural gas used to generate electricity has increased significantly in recent years, natural gas inventories remain at an all-time high primarily due to economic extraction of natural gas from shale formations.



Q. In the Staff Report did Mr. Eaves indicate that with the implementation of an FAC, natural gas hedging is no longer necessary to mitigate monthly fluctuations in natural gas prices?

A. This is how I understand his position. Mr. Eaves described to the Commission how the mechanics of an FAC act to protect shareholders and ratepayers from natural gas price volatility, thus removing the need to mitigate price volatility through financial hedges:

> GMO's FAC protects both shareholders and rate payers from unexpected changes in fuel and purchased power costs. The FAC protects shareholders by allowing GMO to bill customers for actual fuel and purchased power costs through periodic rate adjustment filings. Customers are protected from price fluctuations resulting from these same periodic rate adjustments. As fuel and purchased power prices rise or fall customers are billed the incremental difference over an extended period of time.

Q. Does OPC agree with the Staff that the implementation of the FAC and its built-in expense smoothing mechanism has eliminated the need to hedge natural gas for price volatility?

A. Yes, OPC very much agrees with Staff on this issue.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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Hedging Under Scrutiny [1]

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Planning ahead in a low-cost gas market. Julie Ryan and Julie Lieberman

Julie Ryan is a vice president and **Julie Lieberman** is a project manager with Concentric Energy Advisors. The authors acknowledge the editorial contributions of Steve Caldwell and Carrie O'Neill.
Fortnightly Magazine - February 2012 [2]

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.

Exhibit No.
Issue: Fuel and Purchased Power
Expenses: Risks Associated with Expenses; Fuel Adjustment Clause; In-Service Criteria; O&M Expense
Witness: Brad P. Beecher
Type of Exhibit: Direct Testimony
Sponsoring Party: Empire District
Case No.
Date Testimony Prepared: April/04

Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

Brad P. Beecher

April 2004

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OF
BRAD P. BEECHER
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY
OF
BRAD P. BEECHER
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION
CASE NO.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Brad P. Beecher. My business address is 602 Joplin Street, Joplin, Missouri.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. The Empire District Electric Company ("Empire" or "Company"). I am Vice President – Energy Supply.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND FOR THE COMMISSION.

A. I graduated from Kansas State University in 1988 with a Bachelor of Science Degree in Chemical Engineering.

Q. PLEASE GIVE AN OVERVIEW OF YOUR PROFESSIONAL EXPERIENCE.

A. I was employed by Empire immediately following my graduation from Kansas State University in May of 1988. From May of 1988 through August of 1999, I held roles as a staff engineer at Empire's Riverton Power Plant, in budgeting and fuel procurement in our Energy Supply Department, and finally as Director of Strategic Planning. I went to work in August 1999 for Black & Veatch. Between August of 1999 and February of 2001, I held roles as Service Area Leader for the Strategic Planning Group of Black & Veatch's Power Sector Advisory Services and as Associate Director of Marketing and Strategic Planning in their Energy E&C Group. I rejoined Empire as General Manager – Energy Supply in February 2001. I was elected Vice President – Energy Supply in April 2001. Currently, my responsibilities include all of Empire's energy supply functions including power plant construction, operation & maintenance, energy trading, and fuel procurement.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS CASE BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. My direct testimony provides information on several topics. In Section II, I describe Empire's need for either a Fuel and Purchased Power Adjustment Clause ("FAC") and/or an Interim Energy Charge ("IEC") to appropriately address the volatility of natural gas and non contract purchase energy. In Section III, I present information surrounding Empire's successful proactive management of on-system fuel and purchased power costs. In Section IV, I present the proposed level of expenses for fuel and purchased power for the test year in this case and describe some of the challenges in determining the appropriate level of expense. In Section V, I address proposed in-service criteria for Energy Center Units 3 and 4 that were declared commercial in April of 2003.

II. EMPIRE'S NEED FOR FUEL ADJUSMENT CLAUSE OR INTERIM ENERGY CHARGE

Q. WHAT IS YOUR UNDERSTANDING OF THE ROLE AND RESPONSIBILITY OF THE COMMISSION WITH REGARD TO SETTING RATES FOR ELECTRIC UTILITIES?

A. The Commission is responsible for determining and prescribing just and reasonable rates for the services furnished by electric utilities under its jurisdiction. In accordance with the Commission's own mission statement, such just and reasonable rates should ensure that Missourians receive safe and reliable utility services and that a regulatory process is used that is efficient and responsive to all parties. To me, this means that rates need to be set at a fair level for all parties involved and that risk tradeoffs need to be evaluated in setting those rates. As the cost of capital experts' testimony shows, the returns this Commission has previously allowed have been inadequate and are lower than the rates of return other state Commissions' have allowed for utilities, the vast majority of which also enjoy the benefit of the risk-mitigating fuel adjustment clauses.

Q. WHAT METHOD IS EMPIRE PROPOSING IN THIS CASE TO DETERMINE FUEL AND PURCHASED POWER COST?

A. Empire has filed tariffs indicative of three separate methods. Our preferred method would be a Fuel and Purchased Power Adjustment Clause (FAC). Another alternative filed is an Interim Energy Charge. A third, but less desirable alternative would be a traditional forecast which most certainly will be highly contentious among the parties. We believe this third alternative is the most unsatisfactory of the three methods and will produce the least reasonable outcome. In the past, the revenue requirements determined using this method led to significant debates among the parties that we are trying to avoid in this rate proceeding and that, based on current market conditions, would virtually certainly lead to under-recovery of fuel costs.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE IEC.

A. In Empire's Missouri rate case (Case No. ER-2001-299), the parties acknowledged the volatility of natural gas and unpredictability of spot purchased power and the Commission ultimately implemented a rider termed the IEC. In addition to a fixed amount of fuel and purchased power expense that Empire was allowed to recover through its rates, the IEC allowed a new charge that was subject to true-up and refund to account for the volatility and unpredictability of natural gas and spot purchase power prices. I believe that it was a good method to remove a portion of the volatility that can negatively affect Empire, its customers, and its shareholders. Recently, the Commission approved a similar rider also termed the IEC in Case No. ER-2004-0034 involving Aquila, Inc. The testimony in that case involving the IEC follows much of the same reasoning as was utilized in the 2001 Empire case.

Q. DOES EMPIRE BELIEVE THE IEC IS AN EFFECTIVE MEANS OF ADDRESSING THE VOLATILITY IN THE NATURAL GAS AND WHOLESALE ELECTRICITY MARKETS?

A. Yes. Implementation of an IEC will result in rates that allow Empire to recover at least the level of fuel and purchased power expenses which it has experienced on an historical basis, and at most, costs which were recently prevalent in the market. The IEC would allow Empire to ultimately recover its actual prudently incurred fuel and purchased power costs (as determined through a Staff audit) within a band set during a rate proceeding. Since there is a cap on the IEC, Empire may still be subject to losses due to large swings in the natural gas and wholesale electricity markets. An IEC however, does help to minimize the effects of some of the peaks and valleys that are certain to occur in the natural gas and purchased power markets. Since the IEC contains a floor, an IEC does not prevent Empire's customers from paying more than actual fuel and purchased power costs in the event those costs are below the floor.

Q. DO YOU HAVE AN ALTERNATIVE TO THE IEC?

A. Yes. The IEC, as its name suggests, is only an "interim" solution. The IEC does not stop natural gas from being volatile or wholesale purchase power prices from changing. By virtue of its past design, it will expire which will nearly automatically necessitate another full blown rate proceeding. Such full blown rate proceedings take time and result in significant expenses for which our customers or shareholders must ultimately pay. Empire is supporting efforts by a broad range of utilities within the State of Missouri to implement fuel adjustment clause legislation. To the extent that legislation is enacted to enable a fuel adjustment clause, we can avoid lags in passing through changes in fuel costs (up and down) which should provide for a more financially sound utility. In total it should further the Commission's mission of providing a process to allow for just and reasonable assurance that Missourians receive safe and reliable utility services and that a regulatory process is used that is efficient and responsive to all parties.

Q. WHY IS EMPIRE PROPOSING A FAC OR IEC IN THIS RATE CASE RATHER THAN APPROACHES THE COMPANY HAS SUPPORTED IN THE PAST?

A. First and foremost, addressing high natural gas and volatile spot purchase power contracts is essential to Empire's continued financial health. Empire burned 6.5 million MMBtu of natural gas in 2003 and we expect to burn nearly 10 million MMBtu in a normalized year. Understating natural gas prices in a rate proceeding by only $1/MMBtu could cause our shareholders to absorb $6.4 M in reduction to retained earnings in just 1 year. The $6.4 M represents nearly 20% of the retained earnings accumulated in our Company since its formation in 1944. The traditional regulatory process simply takes too long for us to absorb a mistake that could easily be twice as large.

Empire believes that a contested rate case can protect the interests of both the Company and its customers. However, a rate case result that does not recognize nor provide for the volatility associated with natural gas prices and purchased power prices through either an IEC or FAC does not provide that protection for either its customers or its shareholders.

Without an IEC or a FAC, the parties to the case are forced to stake out positions. The Commission Staff runs its computer models and uses a combination of historical data and judgment to determine a number for fuel and purchased power that the Company nearly always considers is too low; Staff then stakes its position on the low number throughout the contested rate case. Empire conversely uses a combination of historical data and judgment to determine a number as the value for fuel and purchased power, that the Staff nearly always considers too high. This tends to force the Commission to decide between what might be extremes, or to pick some random number in the middle when there may be no concrete evidence to support it. All of this seems to be unproductive when history shows that is impossible to accurately predict what the actual prices will be.

If the rate case revenues are set by the Commission at a value that is too low, the customers do not cover the operational costs incurred by Empire. Under this scenario, over the long run, both shareholders and customers suffer the consequences. The stock does not hold its value and the cost of capital increases as Empire's ratings fall. If the rate case revenues are set too high, the customers pay more than the operational costs incurred with no mechanism for true-ups or refunds.

As stated earlier, in Empire's Case No. ER-2001-299 an IEC was implemented to deal with most of the same issues. At the time of the stipulation gas prices were high from a historical perspective (over $5.50/MMBtu). However, it wasn't too far back in history when gas prices were low (around $3.50/MMBtu). The IEC helped to appropriately balance gas prices and non-contract purchase power risks. In the months that followed the implementation of the IEC, natural gas and wholesale power prices fell and our customers subsequently received a refund that they would not have received if gas prices had been set at then-current levels without an IEC in place. We are once again at a time when the price for natural gas is quite high and no one can be certain where it will go from here. I think the fact the Commission and other parties to Case No. ER-2004-0034 (Aquila) recently recognized this and implemented an IEC is evidence that the Commission is attempting to bring a reasonable and practical solution to this problem by balancing the competing interests.

III. EMPIRE'S MANAGEMENT OF FUEL AND PURCHASED POWER EXPENSES

Q. WHAT TRENDS HAVE BEEN DRIVING CHANGES IN EMPIRE'S FUEL COSTS?

A. Empire has been adding gas-fired generation since the mid-1990s. The units added included approximately 90 MW in 1995, 150 MW in 1997, 150 MW in 2001 (the 1997 and 2001 units became part of State Line Combined Cycle) and 100 MW in 2003. While these units have provided for low capital cost capacity, the variable energy costs are more expensive than the coal-fired energy that made up a majority of our energy mix in the early 1990s. Natural gas is currently the primary fuel source for 704 MW of our 1264 MW of generating capacity (56%). A total of 30% of our energy in 2003 was generated from our natural gas fired units or purchased on the spot market.

Empire's gas-fired capacity additions were in-line with a national trend given that gas-fired capacity additions were viewed as more friendly to the environment than coal and requiring less capital investment in a time of great uncertainty as to the regulatory treatment generation would be afforded. The gas-fired generation trend also affected the wholesale power market. Because so many simple cycle gas turbines and combined cycle units were added throughout the U.S. during the 1990s and early 2000s, the prices for spot market wholesale power now reflect gas-fired generation pricing many hours of the year.

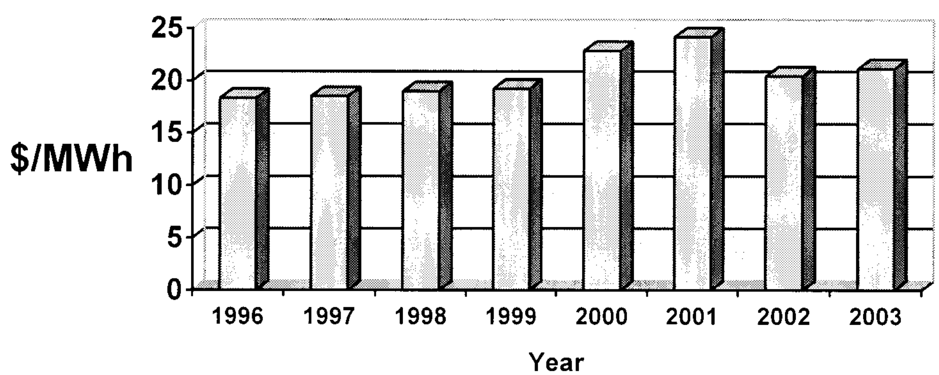
Compounding the effects of the addition of gas-fired generation, natural gas prices have increased from between $2-3/MMBtu in the mid-1990s to over $4.50/MMBtu for the majority of 2003.

Q. HOW HAS THE ADDITION OF THE GAS-FIRED GENERATION AND THE INCREASE IN GAS PRICES AFFECTED EMPIRE'S OVERALL ENERGY COSTS?

A. Empire's costs on a $/MWh basis increased from $18.33/MWh in 1996 to $21.15/MWh in 2003. The average annual increase from 1996 through 2003 was just 2.06%. Given the shift in fuel mix from coal to gas and given the dramatic increase in wholesale natural gas prices, I believe this modest increase in costs is a direct result of Empire's active management of prices and risks. Information pertaining to on-system fuel and purchased power costs for 1996 through 2003 is presented in Figure 1 below.

Figure 1

On-System Fuel & Purchased Power Costs



Q. THE COSTS APPEAR TO PEAK IN 2000 AND 2001. WHAT CAUSED THE INCREASE?

A. Our annual costs peaked at $24.17/MWh in 2001. We actually hit a twelve-month rolling peak of $24.79 at the end of November 2001. The increase in expenses was driven by many factors. One of the main factors was an increase in natural gas prices. Natural gas prices increased dramatically in 2000 and 2001. We were buying gas on an as needed basis and as the natural gas prices ran up so did our expenses. The increase in expenses affected net income directly. An extended outage on our low-cost Asbury generating station also contributed to this peak in costs. During the outage, we upgraded controls and replaced cyclone burners. We also found we had a damaged main generator step-up transformer and had to operate in a derated condition for a period of time.

Q. WHAT HAS EMPIRE DONE TO ALLEVIATE SOME OF THE RISK DUE TO VOLATILE NATURAL GAS PRICES?

A. While the 2001 IEC was in effect, Empire implemented an Energy Risk Management Policy and added personnel that specifically focus their efforts on the purchasing and hedging of power and natural gas. The Energy Risk Management Policy sets targets as to how much natural gas Empire must have hedged at any point in time. In general the Risk Management Policy brings more sophistication and consistency to our fuel procurement. Our risk management policy is attached as Schedule BPB-1.

Q. YOU MENTION THE TERM "HEDGED". PLEASE EXPLAIN WHAT THE TERM "HEDGED" MEANS.

A. Hedging is a strategy used to offset investment or price risk, specifically to protect against price movements. Hedging can be used by individual investors, as well as companies and financial institutions. Empire's Risk Management Policy allows the utilization of traditional physical purchases and the utilization of financial tools such as call options, collars, swaps, and futures contracts to protect against adverse price movements.

Q. WHAT DETERMINES HOW MUCH NATURAL GAS IS HEDGED BY EMPIRE AND WHEN SUCH NATURAL GAS IS HEDGED?

A. Empire originally enacted a Risk Management Policy ("RMP") in 2001 that establishes the approach and internal rules that Empire will use to manage specifically its power and natural gas commodity risk. The policy is revised approximately annually to reflect lessons learned and changes in markets and financial instruments. The RMP targets for hedging of natural gas are:

A minimum of 10% of year four expected gas burn
A minimum of 20% of year three expected gas burn
A minimum of 40% of year two expected gas burn

A minimum of 60% of year one expected gas burn

Up to 80% of any year's expected requirement can be hedged if appropriate, given the associated volume risk.

Thus, by the end of 2003, our policy required that we have 60-80 percent of 2004 gas needs hedged, 40-80 percent of 2005 needs, 20-80 percent of 2006 needs, and 10-80 percent of 2007 needs. Empire is in effect dollar cost averaging the price of natural gas to remove volatility for both Empire and our customers. Schedule BPB-2, attached to this direct testimony, shows Empire's natural gas positions as of April 16, 2004.

Q. HOW WOULD YOU CHARACTERIZE EMPIRE'S HEDGING STRATEGY?

A. Empire's hedging strategy has been valuable as it has provided significant stability to our customers rates and shareholder returns. For example, in 2003 since we did not have a rate proceeding, Empire's shareholders would have paid approximately $13.5 million more for natural gas had Empire not hedged its natural gas purchases. Alternatively, if we had been able to effect a quick rate proceeding, our customers would have paid more. As shown on Schedule BPB-3, Empire paid an average hedged price in 2003 of $3.02/MMBtu for natural gas. If the natural gas had not been hedged, the weighted average price based on NYMEX close would have been a higher value of $5.12/MMBtu.

Q. WHAT IS NYMEX?

A. NYMEX stands for New York Mercantile Exchange. NYMEX provides a standard contract by which to hedge natural gas commodity risk. The standard contract point is at the Henry Hub in Louisiana. It is commonly considered the most liquid price transparent pricing point for natural gas in the U.S.

Q. PLEASE COMPARE YOUR 2003 ACTUAL COSTS OF NATURAL GAS TO 2003 CLOSING NYMEX PRICES.

Table 1

NYMEX Market Contract Closes

Month of 2003	**Price $/MMBtu**
January	4.97
February	5.66
March	9.00
April	5.12
May	5.11
June	5.96
July	5.33
August	4.65
September	4.88
October	4.44
November	4.46
December	4.88

As a comparison, Empire's average cost of natural gas commodity in 2003 was $3.02/MMBtu, which is lower in every month than the value of NYMEX contracts.

Q. WHAT WAS THE MOST SIGNIFICANT FACTOR IN ALLOWING EMPIRE TO EXPERIENCE GAS COSTS AT THE $3.02/MMBTU LEVEL?

A. Our hedging program is designed to provide more predictable gas prices that are fair to the customer and shareholder. We began our hedging program in late 2001. At that time, natural gas commodity costs were between $3/MMBtu and $4/MMBtu. Pursuant to our RMP, we hedged a portion of our needs. In essence we took low cost positions in 2001 and 2002 relative to the 2004 market. This policy served Empire and its customers very well in 2003.

Q. WHAT WOULD EMPIRE'S AVERAGE PRICE IN 2003 BEEN FOR NATURAL GAS IF THE ACTUAL PRICE OF NATURAL GAS HAD FALLEN TO $2/MMBTU?

A. Many variables would have changed, including the economy, our customers demand, and spot purchased power prices to name a few. But, ignoring those, our expense for natural gas would have been in the $3.02/MMBtu range. In other words, we took positions that hedged against price fluctuations and that we believed protected both customer and shareholder from excessive risks of fuel price volatility.

Q. DO YOU EXPECT YOUR HEDGING PROGRAM TO PRODUCE RESULTS IN THE $3/MMBtu PRICE RANGE IN 2005?

A. No. We have only about 60% of our anticipated 2004 needs and 40% of our 2005 needs hedged at an average price of $4.15/MMBtu. As of the market close on April 21, 2004, the futures market for natural gas contracts were priced as shown in Table 2. In order for Empire to achieve average gas prices of $3/MMBtu in 2004 or 2005, the price for natural gas would have to fall well below $3/MMBtu to offset the $4.15/MMBtu contractual obligations that we already have in place. With current prices for 2004 and 2005 consistently above $5/MMBtu, Empire cannot possibly expect its hedging program to result in gas prices in 2004 or 2005 as low as $3/MMBtu. Rather, average prices will have to be expected to increase above the $4.15 level. In fact, based on current forecasts, Empire expects natural gas costs to increase to $4.50 MMBtu for 2004.

Table 2

Future Market Prices as of Market Close March 2, 2004

Month	**2004**	**2005**
January		6.26
February		6.21
March		6.02
April		5.41
May	5.59	5.28
June	5.66	5.28
July	5.74	5.33
August	5.78	5.34
September	5.75	5.29
October	5.77	5.31
November	5.94	5.47
December	6.12	5.62

IV. PROPOSED LEVEL FOR FUEL AND PURCHASED POWER EXPENSES

Q. WHAT LEVEL OF EXPENSE FOR ON-SYSTEM FUEL AND PURCHASED POWER IS EMPIRE RECOMMENDING IN THIS CASE?

A. As stated earlier, Empire's first preference is a FAC. Empire recommends a FAC that has charges based on an expense of $121,665,153 total Company for on-system fuel and purchased power for the projected energy requirements of 5,042,800 MWh. On a unitized basis, this value of revenue requirements reflects expenses at a level of $24.13/MWh. Adjustments would be made on a periodic basis conforming to law or the terms of a stipulation.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I utilized actual twelve-month ending cost and tried to make just and reasonable adjustments for a minimal number of variables. I made five adjustments from actual cost; they are 1) normalized energy, 2) natural gas costs, 3) new natural gas transportation, 4) escalation of delivered coal prices, and 5) the replacement of the American Electric Power ("AEP") short-term contract energy. Table 3 summarizes the adjustments.

Table 3

Adjustments to Twelve Month Ending December 31, 2003

	MWh	$	$/MWh
Actual TME 12/31/03	4,950,161	104,714,009	21.15
Weather/Growth Adjustment	92,639	2,130,697	29.24
New Gas Transport		2,250,000	
Delivered Coal Price Escalation (2%)		523,893	
Natural Gas Prices (3.02 to 4.60 for 6.45M MMBtu)		10,190,379	
Replace AEP Short-term Contract Energy		1,278,108	
Total	5,042,800	121,665,153	24.13

Q. WILL YOU PLEASE PROVIDE THE RATIONALE BEHIND EACH ADJUSTMENT?

A. Yes.

Actual TME 12/31/03

This row in the table represents actual MWh, $, and $/MWh for calendar year 2003. As presented in Figure 1 above, 2003 results are in line with 2002 results. There were no major or abnormal outages on our generating plants. I would not expect the wholesale spot market to dramatically change year over year.

Weather/Growth Adjustment

This adjustment was made to match requested expenses with the normalized revenues and kWh in this case. The MWh were priced at Empire's average incremental power cost for 2003 of $29.24/MWh.

New Gas Transport

Empire entered into a gas transportation agreement with Southern Star to help serve the new combustion turbines at Empire's Energy Center. The pipeline upgrade was expected to be in service during the fall of 2003. However, due to construction difficulties, the pipeline was not placed in service at that time. We now expect the pipeline to be in service by June 2004 and for Empire to begin making its contractually obligated payment at that time. This amounts to an annualized expenditure of $2,250,000.

Delivered Coal Price Escalation

This adjustment was made to account for the escalation of coal commodity and freight prices that Empire experiences on an annual basis under current contract terms. Empire has contracts with various coal and freight providers that have differing terms of escalation. When all of these terms are taken into consideration, Empire's commodity plus freight price of coal stands to increase approximately 2% (on a $/MMBtu basis) in 2004 when compared to 2003 prices.

Natural Gas Prices

Our hedging program resulted in average natural gas commodity prices of $3.02/MMBtu in 2003 for the 6,450,000 MMBtu of natural gas that we burned. In 2005, when rates will be in effect from this case, we have about 4,200,000 MMBtu of gas hedged at $4.15/MMBtu and the remainder is unhedged. As you can see in Table 2, 2005 gas prices currently average $5.44/MMBtu. Applying $5.44/MMBtu to 2,250,000 MMBtu and $4.15/MMBtu to 4,200,000 MMBtu gives a weighted average price of $4.60/MMBtu. Applying the difference between $4.60/MMBtu and $3.02/MMBtu to the actual burn of 6,450,000 MMBtu gives an adjustment of $10,190,379.

Replace AEP Short-term Contract Energy

In 2002 and for the first half of 2003, Empire was able to procure a favorable short-term purchase power contract with AEP. In 2003 this contract contributed 201,428 MWh to Empire's on-system energy needs at an average price of $29.55 (average price includes capacity demand charges). This power is no longer available from AEP. An adjustment has been made to replace this energy with energy from Empire's State Line Combined Cycle ("SLCC") unit at a price of $35.90/MWh, the average price found in Run 1 for SLCC generation presented in Ms. Tietjen's testimony.

Q. HOW DOES THIS METHOD OF CALCULATING FUEL AND PURCHASED POWER COSTS COMPARE TO THE METHOD USED IN PREVIOUS RATE CASES?

A. In previous rate cases in which I have been involved in Missouri, fuel and purchased power expenses have generally been estimated by both Company and Staff utilizing their respective hourly computer models. In almost every circumstance, we ended up with a very sophisticated "battle of the models." I believe that the models themselves will generally provide the same answer given the same input data. The arguments that Empire and the Staff typically have had revolved around just a couple of input variables. The variables of contention have been natural gas prices and the price as well as the availability of non-contract purchase energy. I reviewed the Fuel and Purchased Power testimony in the recent Aquila electric rate Case No. (ER-2004-0034) and the large fuel and purchased power issues in that case were also natural gas pricing and non-contract purchased power costs and availability.

Q. WHY HAVE NATURAL GAS COSTS BEEN AN ISSUE?

A. In my opinion, they have been an issue because natural gas prices are so volatile. The Staff wants to make sure the consumers get the benefit of low gas prices and selects a method or data that will yield a low gas price forecast. The Company wanted to make sure the shareholders do not shoulder the weight for high gas prices and selects a method or data that results in a higher gas price forecast. Neither the Staff, nor the Company can accurately forecast the natural gas prices however. This is why the Company is now strongly advocating the use of an FAC or an IEC. I, as well as future witnesses for Staff, The Office of Public Counsel, and other intervenors, could write pages of testimony showing forecast of prices, why the futures market is not a good indicator of future prices, and why the past prices are not a perfect predictor of future prices. However, at this time I am hopeful that all parties to the case will see the necessity of either the FAC or IEC and we can focus our efforts on appropriate measures and conditions around the FAC or IEC.

Q. WHAT ABOUT NON CONTRACT PURCHASE ENERGY?

A. Non-contract purchase energy is even more difficult to forecast. The price and availability of non-contract energy is based upon conditions in the market resulting from utilities other than Empire both inside and outside of the State of Missouri. Factors that will affect the price and availability of that energy include transmission cost, transmission availability, coal prices, natural gas prices, planned and forced outage rates, weather, heat rates, water availability, and market perception to name just a few – all from organizations other than Empire. In addition, non-contract energy generally directly competes with the natural gas-fired generation and hence the quantity of gas the model projects will be utilized in test year. If too much non-contract energy at a cheap price is made available in the model, then the natural gas-fired resources in the model will not be utilized. Therefore, it is possible to agree on a gas price and still significantly disagree on fuel and purchased power expense. Again, a review of the issues in the recent Aquila case read like a review of the Empire cases in 2001 and 2002. Without the implementation of a FAC or IEC, this issue is sure to result in "battling of the models" in this case.

Q. WHAT IS EMPIRE RECOMMENDING FOR AN IEC?

A. Empire witness Jill Tietjen concurrently files testimony in the more traditional "model" fashion. The model provides the basis for the base charge of $105,000,000 ($20.82/MWh) and the IEC of $20,000,000 for a total of $125,000,000 ($24.79/MWh). The base and the IEC were derived by reflecting forecast natural gas pricing and spot purchase power price assumptions in our hourly dispatch model. The assumptions surrounding the model are also provided by Ms. Tietjen.

Q. IF EMPIRE IS NOT ABLE TO UTILIZE ONE OF ITS PREFERRED METHODS TO DETERMINE FUEL AND PURCHASED POWER COSTS (AN IEC OR FAC), WHAT WOULD EMPIRE RECOMMEND FOR BASE ON-SYSTEM FUEL AND PURCHASED POWER COSTS?

A. Under this circumstance, Empire would revert to the more traditional production forecast modeling of on-system fuel and purchased power costs. Empire's base run (Run 1) forecasts on-system fuel and purchased power costs of $123,017,327 ($24.39/MWh) for 5,042,800 MWh of energy, which Empire's rate filing is based on. Again, the assumptions surrounding the model are presented in Ms. Tietjen's testimony. It should be noted that this modeled value for on-system fuel and purchased power costs compares very favorably to the simple, straight-forward method I presented above. By making only five adjustments to twelve-month-ending 2003 on-system fuel and purchased power costs, I arrived at a cost of $121,665,153 ($24.13/MWh), a difference of only $1.35 million or 1.1 percent.

V. IN-SERVICE CRITERIA FOR ENERGY CENTER UNITS 3 AND 4

Q. DO YOU HAVE PROPOSED IN-SERVICE CRITERIA FOR ENERGY CENTER UNITS 3 AND 4?

A. Yes I do. Energy Center Units 3 and 4 were declared commercial by the Company in late April 2003. Through February 2004, these units have provided 52,724 MWh to the system and have run for a total of 2,587 hours. Under any criteria, these units have performed very well for the Company and its customers. During the fall of 2002, Empire worked with Staff to attempt to ascertain the in-service criteria that would be utilized on Energy Center 3 and 4. Empire proposes the following criteria:

1. All major construction is completed.
2. All pre-operational tests have been successfully completed.
3. Unit will successfully demonstrate its ability to initiate the proper start sequence resulting in the unit operating from zero rpm (or turning gear) to full load when prompted at a location (or locations) from which it will be normally operated.
4. If unit has fast start capability, unit will demonstrate its ability to meet fast start criteria.
5. Unit will successfully demonstrate its ability to initiate the proper shutdown sequence from full load resulting in zero rpm (or turning gear) when prompted at a location (or locations) from which it will be normally operated.
6. Unit will successfully demonstrate its ability to operate at minimum load for one hour.
7. Unit will successfully demonstrate its ability to operate at or above 98% of full load for four continuous hours.
8. Unit will successfully meet all operational guarantees.

9. Transmission facilities shall be capable of exporting the entire plant net capacity.
10. Units shall demonstrate the ability to start on distillate fuel.
11. Units shall demonstrate the ability to transfer from natural gas to distillate fuel.

Q. HAVE THE ENERGY CENTER UNITS 3 AND 4 MET EACH OF THE PROPOSED IN-SERVICE CRITERION?

A. Yes they have. Schedule BPB-4 contains a report completed by plant management detailing and documenting the performance for each of the criteria.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Colorado Springs Utilities
It's how we're all connected

Natural gas hedging program

https://www.csu.org/Pages/nghedging-b.aspx

The objective of our natural gas hedging program is to keep customer rates relatively stable. Throughout the program, our rates have remained at or below the average of comparable cities. Hedging is just one part of a much larger strategy to keep rates low and stable.

What is natural gas hedging?
Hedging is a means by which prices for natural gas are "locked in" ahead of time using financial tools. The practice is common in many industries including utilities.

Why does Colorado Springs Utilities hedge?
Wholesale natural gas prices are among the most volatile of any commodity. The purpose of hedging is to reduce dramatic price swings in volatile commodity markets. Hedging is a means to ensure more stable prices and prevent the effects of high price spikes for customers.

Do other gas utilities hedge?
Yes, hedging is a common industry practice. Ninety-two percent of gas utilities used hedging in 2010.

In which years did Colorado Springs Utilities hedge for natural gas?
From 1997 to 2010, Colorado Spring Utilities hedged much of its anticipated natural gas volumes for three years into the future. While hedging ceased in 2011, forward fixed price positions were placed at the end of 2010 to hedge forecast gas sales into 2013.

Does hedging ensure lowest price?
No, since future prices aren't known, sometimes the hedged price is lower than market at delivery, but often it is higher than market price.

Since hedging is not designed to ensure lowest price, what is done to ensure competitive prices for customers?
Hedging is just one of many tools we use to manage natural gas costs for our ratepayers. Some programs are designed to achieve lower prices for customers, including closely monitoring markets and prices and taking advantage of daily market fluctuations. Energy traders work with many different suppliers to seek the lowest available supply each day for customers.

In 2008, Colorado Springs Utilities negotiated a gas "prepay" agreement that leverages our municipal utility status to purchase a portion of future volumes at a guaranteed discount, resulting in savings of $150 million over the life of the program. Large volume storage of natural gas and use of the air propane plant contribute to reliable supply and keeping costs low.

Programs for large commercial customers to purchase their own gas supply have also been implemented, allowing them to determine their own level of natural gas price risk.

How do our customers' natural gas rates compare to other utilities?
We have remained below the average of other cities in natural gas rates from 2002-2012, based on the 22-city annual rate competitiveness survey.

If hedged prices result in higher than market price for gas, is that losing money?
No. It means the cost of hedging was higher than market prices, and is part of the cost of achieving the goals of a hedging program – more stable prices and insurance against high price spikes.

What has happened to natural gas prices in recent years?
After years of large wholesale price increases and dramatic volatility, prices dropped significantly in 2008. Prolonged, poor economic conditions and a fundamental supply increase from widespread use of horizontal drilling and formation fracturing technologies kept prices relatively low. Utilities has taken advantage of current lower prices on non-hedged supply and passed the lower costs on to customers.

Are we hedging now?
No. With market costs declining, we began a significant review of our hedging program in 2009, and in 2010 reduced volumes and lengths of hedges. With continuing apparent market stability, all hedging was suspended in 2011. The small amount of hedged supply still on the books will expire in 2013.

Will we hedge in the future if the market becomes more volatile, or prices rise significantly?
While natural gas prices have risen in the past year, prices have remained relatively stable and are predicted to stay relatively stable for the short to medium term. Utilities is reviewing a range of alternatives to manage future price volatility, including reinstating hedging. The Utilities Board will be engaged on decisions to implement such alternatives.

Colorado Springs Utilities
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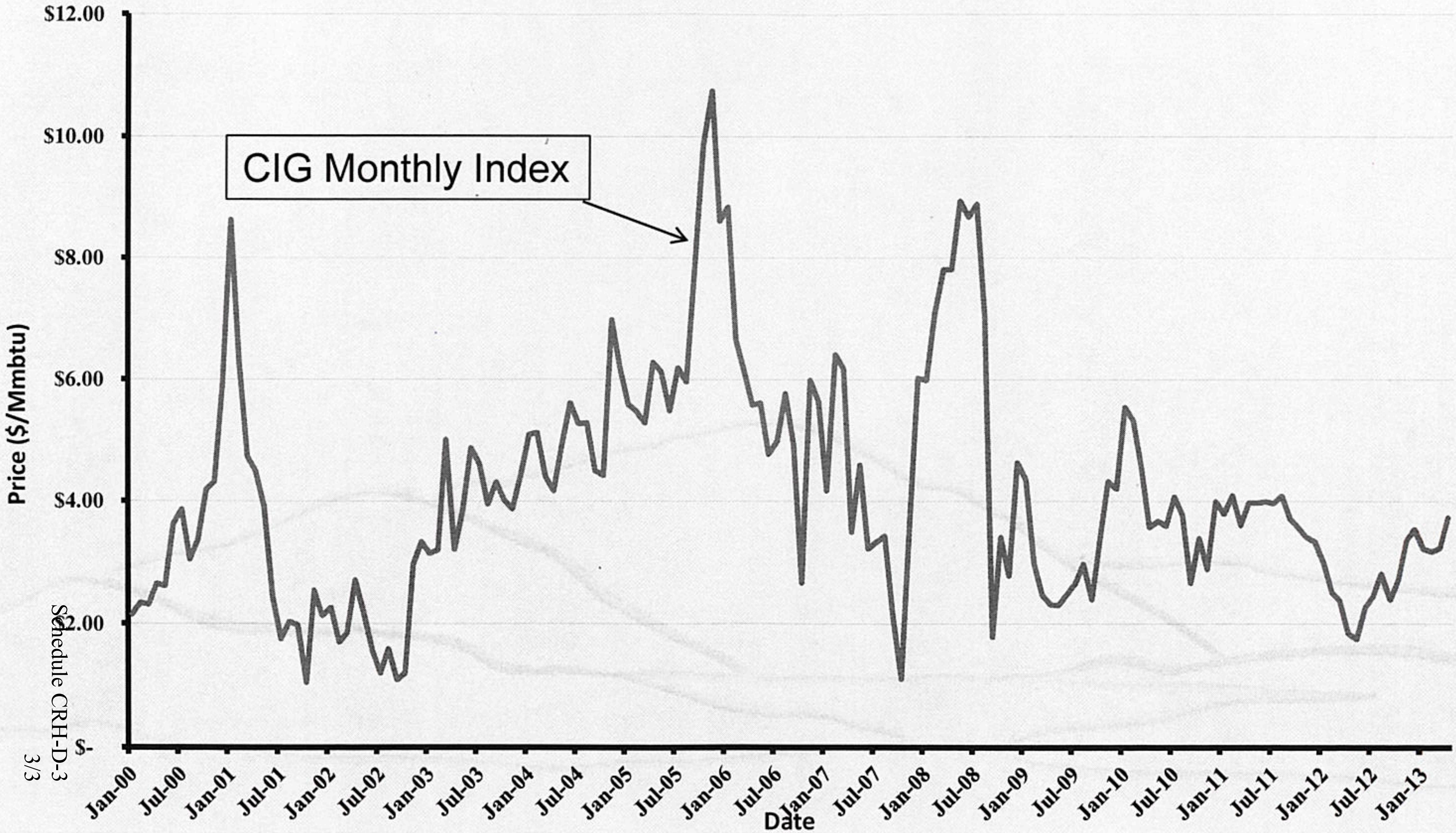
Natural Gas Price Volatility 2000 - 2012



Schedule CRH-D-3
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ELECTRICITY | NATURAL GAS | WATER | WASTEWATER