BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	**)**	
OF OKLAHOMA GAS AND ELECTRIC	**)**	
CORPORATION FOR APPROVAL OF A	**)**	**DOCKET NO. 08-103-U**
GENERAL CHANGE IN RATES AND	**)**	
TARIFFS	**)**	

DIRECT TESTIMONY OF
WILLIAM B. MARCUS

on behalf of

THE ARKANSAS ATTORNEY GENERAL

January 13, 2009

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ARKANSAS PUBLIC SERVICE COMMISSION
DOCKET 08-103-U

DIRECT TESTIMONY OF WILLIAM B. MARCUS
ON BEHALF OF THE ARKANSAS ATTORNEY GENERAL

I. Introduction

Q. Please state your name, business affiliation and address.

A. I am William B. Marcus. I am Principal Economist for JBS Energy, Inc., 311 D Street, West Sacramento, California 95605.

Q. Please provide your qualifications.

A. My qualifications are attached as Exhibit WBM-1. I have over 30 years experience with energy utility issues. I have previously testified or made formal comments before about forty federal, state, provincial, and local utility and environmental regulatory bodies in the U.S. and Canada on issues including utility restructuring and performance-based ratemaking, revenue requirements, resource planning, and cost-of-service and rate design. I have filed testimony at this Commission on a number of occasions, including the recent Entergy Arkansas, Inc. ("EAI"), Oklahoma Gas and Electric ("OG&E") Arkansas Electric Cooperative Corporation ("AECC"), The Empire District Electric Company ("EDE"), Arkansas Western Gas Company ("AWG"), Arkansas Oklahoma Gas Corporation ("AOG") and CenterPoint Energy Arkla ("Arkla") rate cases (Dockets 06-101-U; 06-070-U; 04-141-U; 04-100-U; 06-124-U and 04-176-U and 02-227-U ; 04-100-U; 07-026-U, 05-006-U and 02-024-U; and 06-161-U, 04-121-U and 01-243-U respectively), several other cases involving Entergy (Dockets 08-149-U, 06-152-U, 01-041-U and 01-184-U), the AWG Weatherization case (Docket 05-111-P), both the September, 2000 and September, 2001 phases of the Commission's restructuring investigation (Docket 00-190-U), Docket 98-339-U (the last Southwestern Electric Power Company [SWEPCO] rate case), and approximately 20 unbundling cases for co-ops and investor-owned utilities, most of which were settled.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arkansas Attorney General. I was retained to review a number of aspects of the general rate application filed by Oklahoma Gas and Electric Company ("OG&E" or "the Company").

Q. What is the overall context of this rate case?

A. OG&E has requested a rate increase of $26.9 million

The Attorney General's investigation does not involve the detailed accounting audit provided by the Staff but looks at a number of specific areas. This analysis has identified at least $10.87 million in reductions from Arkla's requested rate increase in areas including the capital structure and return on equity, incentive bonuses including stock-based compensation, directors' and officers' (D&O) liability insurance, dues and donations, normalization and changes to the jurisdictional allocation of windpower costs, LIFO accounting for inventory, and treatment of the Red Rock project. We expect that the Staff's detailed audit, including its sampling of invoices, will support additional rate reductions. To the extent that the Commission accepts recommendations of Staff reducing rate base or expenses, or increasing revenues, this would at least further reduce OG&E's requested base rate increase.

Q. What are your detailed recommendations?

A. With respect to rate of return and revenue requirements, I recommend that the Commission:

1. Use a hypothetical capital structure of 45% equity and 55% debt (including short-term debt) after considering comparison companies, instead of OG&E's actual capital structure with over 55% equity.

2. Stay the course and leave the authorized return on equity (ROE) at its current level of 10.00% rather than adopting OG&E's requested 12.25%. (The combination of the two recommendations on capital structure and rate of return creates a $9,315,000 reduction at EAI's proposed rate base).

3. Reduce expenses by a total of $713,000 (Arkansas jurisdictional) for incentive programs. Of this amount, $472,000 results from sharing the portion of the costs of incentive programs for exempt employees, managers, and executives that are related to financial goals on a 50-50 basis to reflect that payments are heavily dependent on goals that benefit shareholders. The remaining $241,000 results from removing costs of performance shares, and similar long-term incentive programs that are awarded preponderantly to a few top managers using criteria largely based on OGE Energy's share price performance.

4. Follow the Commission's long-standing precedent and eliminate $22,000 in the Arkansas jurisdictional portion of Chamber of Commerce dues and miscellaneous civic dues, donations and country club dues.

5. Reduce Edison Electric Institute dues by approximately 50% (Arkansas jurisdictional $14,000 more than OG&E's reduction) to reflect lobbying, marketing, public relations, and advocacy expenses.

6. Follow past commission precedent and share Directors and Officers (D&O) liability insurance 50-50 between ratepayers and shareholders, reducing Arkansas jurisdictional expenses by $41,000.

7. If the Red Rock project amortization is approved (an issue requiring further investigation), reduce expenses by $215,000 (Arkansas jurisdiction) to amortize them over four years rather than two years.

8. Reduce Arkansas jurisdictional rate base by $3,402,000 to reject OG&E's proposal to mark its coal and gas inventory to market and instead continue to apply the Last In First Out inventory accounting specified in OG&E's 10-K annual report to the SEC. These inventory reductions reduce OG&E's revenue requirement by about $311,000 at the Attorney General's recommended rate of return and by a greater amount if the rate of return is higher.

9. Normalize wind power operation and maintenance expenses to reflect the expiration of an expensive contract in 2008, reducing Arkansas jurisdictional expenses by $61,000.

10. Change the jurisdictional allocation of OG&E's Centennial Windfarm to follow the standard energy allocation percentage of 10.59% to Arkansas

instead of an undocumented 11.28%. This change reduces the Arkansas jurisdictional revenue requirement by about $180,000.

Additional disallowances are likely to be reasonable, based on our further investigation and information brought forward by Staff and other parties.

With respect to class cost of service and allocation, I recommend that the Commission:

1. In general, accept the broad outlines of OG&E's cost of service study, and in particular the average and peak allocation for generation and the classification of distribution plant and expenses as demand-related except for meters and services.

2. Make two adjustments to costs in Accounts 907-916 to directly assign the cost of major account representatives to the classes which they serve and to allocate economic development expenses by a broad-based allocation factor such as base rate revenue.

With regard to residential rate design, I recommend that the Commission take the following steps to encourage conservation and reduce the highly promotional nature of OG&E's rates in promoting electric space and water heating, while mitigating customer impacts.

1. Reject OG&E's 80% increase to the residential customer charge.

2. Reject OG&E's proposal to put all energy charge increases on the summer months, which promotes use of electricity instead of natural gas for space and water heating. Instead, provide an average winter rate increase that is 70-80% as large in cents per kWh as the average summer increase.

3. Accept OG&E's proposal in principle to increase the inversion between first and second tier summer rates but mitigate the increase to prevent rate shock with a target tier inversion of 25% of base rates in this case. Further increases in tier inversion should be pursued in future cases.

4. Reduce the difference between the declining blocks in the winter months by about 50% (0.7 cents per kWh) to balance the need to reduce promotion of electric use while mitigating customer impacts.

II. Rate of Return

A. Capital Structure

Q. What capital structure has OG&E proposed?

A. OG&E proposes its actual capital structure of 44.3% long-term debt to 55.7% equity, after adjusting out all short-term debt. However, in the text of his testimony, Dr. Murry makes an incorrect comment claiming that the Arkansas equity capital percentage that he recommends is lower than that of utilities in other states (only 41.96%).[1] He compares the Arkansas data to Value Line data in Schedule DAM-6 without recognizing that the data are not comparable.

Q. Why do you disagree with Dr. Murry's contention that OG&E's Arkansas request is for much less equity than other utilities?

A. Dr. Murry has implicitly assumed that all of the capital used to fund Arkansas rate base that isn't equity is debt. He compares his figures for the Arkansas equity capitalization (which excludes short-term debt, customer deposits, Current and Other Liabilities, and Accumulated Deferred Income Taxes) to Value Line capitalization (which does not include them). He has thus made a significant mistake because he apparently didn't understand the Arkansas Modified Balance Sheet Approach (MBSA), where approximately 22.9% of the rate base is covered by no-cost capital (deferred tax and balance sheet liabilities) and customer deposits. The equity capitalization calculated on the same basis as Value Line is 55.7%. This is the figure that should be compared to Value Line's 48%. When that proper comparison is made, we can see the excessive nature of OG&E's request.

We can easily see that Dr. Murry's claim that OG&E is being given far less equity than other utilities is wrong by referencing a state that does not use the MBSA (like Oklahoma). For example, in Oklahoma, deferred taxes are not a part of the

[1] Docket No. 08-103-U, Direct Testimony of Donald A. Murry, p. 12, lines 21-24.

capital structure. They are an offset to rate base. The ratemaking impact is virtually the same as in Arkansas, but the mechanism by which it is achieved is different. A cash working capital study is done in Oklahoma instead of including all assets in rate base and all liabilities in no-cost capital.[2]

Q. Has Dr. Murry made this mistake in Arkansas testimony before?

A. Yes, in Docket No. 04-100-U (Empire District Electric Company) he made a different erroneous calculation for the same reason – because he did not properly consider the MBSA.[3]

Q. Aside from the correction of the mistake, what is your evaluation of his request for 55.7% common equity?

A. OG&E's capital structure (<u>excluding</u> balance sheet liabilities, deferred income taxes, and deposits) is actually much more heavily weighted to equity than many utilities, including Dr. Murry's entire comparison group, as is shown by comparing OG&E's request to the proxy companies on Schedule DAM-6.

Dr. Murry also does not consider short-term debt as part of capitalization when using Value Line. While OG&E is adjusting out a significant amount of short-term debt, other utilities use it, and it should be considered when looking at utility debt-equity ratios, particularly in the Arkansas context of the MBSA. The Table below shows the capital structure (debt and equity) for Dr. Murry's comparison companies and as requested for OG&E, averaged over four quarters, from Q4 2007 to Q3 2008. Data are taken from Google Finance except for Northeast Utilities where securitized off-balance sheet financing of rate reduction bonds was excluded from the capitalization.

[2] In most states, including Oklahoma, under Dr. Murry's proposal there would be a smaller rate base funded with about 55.7% equity and 44.3% debt, with items such as deferred taxes, customer deposits, and customer advances for construction treated as rate base offsets, and receivables and payables netting through the cash working capital study.

[3] See Direct Testimony of Donald A. Murry in Docket 04-100-U, page 31 lines 5-18 and Schedule DAM-24 and Direct Testimony of William Marcus in Docket 04-100-U, pp. 13 line 15 to p. 14, line 16.

This table shows that OG&E is requesting a capital structure containing more equity than **__all__** of the six comparison companies and more than 8 percentage points above the average equity percentage for the comparison group (even as calculated without short-term debt). If one includes the comparison companies' short-term debt in the structure calculation, OG&E's equity is 13 percentage points above the comparison companies.

__Table 1: Capital Structure Data__

Proxy Company	STD**	LTD	Preferred	Common (with STD)	Common (w/o STD)
DPL, Inc	11.2%	46.1%	1.0%	41.7%	46.9%
Northeast Utilites	5.0%	52.4%	1.6%	41.0%	43.1%
Nstar	11.8%	51.6%	0.0%	36.6%	41.5%
Pepco	7.2%	49.7%	0.0%	43.1%	46.5%
Pinnacle West	7.0%	42.9%	0.0%	50.1%	53.8%
Scana	8.4%	47.4%	1.5%	42.8%	46.7%
Wisconsin Electric Power Co.	17.2%	40.8%	0.1%	41.9%	50.6%
Average	9.7%	47.3%	0.6%	42.4%	47.0%
Adjusted avg. *	**9.7%**	**47.6%**	**0.0%**	**42.7%**	**47.3%**

* Assigning 50% of preferred stock to debt and 50% to equity
** Includes current maturity of long-term debt
Source: Google Finance (average of quarterly balance statements, four quarters ending Sept 30, 2008)

OG&E Request***	0%	44.3%	0%	N/A	55.7%

*** Derived from Murry, page 12

Q. What do you recommend?

A. This Commission has been asked on many occasions to adopt a hypothetical capital structure for utilities with a relatively small amount of equity (like CenterPoint Energy Arkla). It has adopted hypothetical capital structures for several gas companies. Here, we have a company with considerably more equity than comparison utilities.

I recommend moving OG&E from a 55.7% equity position to a hypothetical capital structure with 45% equity (including short-term debt as part of the capitalization), based generally on this review of the comparison group's capital structures. Because OG&E has adjusted out short-term debt, I include the extra capital as long-term debt.

I may revise my recommendation once I have had the chance to review Staff's larger cohort of proxy companies and Staff's treatment of short-term debt. In any case, I will use OG&E's long-term debt interest rate (6.39%) for the entire amount of the remaining capital.

This capital structure – with 45% equity and 55% debt (long-term plus short-term) is stronger than the capitalization of comparison companies and meets the comments by Standard and Poor's, cited by Dr. Murry (page 12 of his testimony in Docket No. 06-070-U) in the past, which are that "the majority of utilities want to get (or keep) their debt-to-capital ratios well below the 55% level."[4]

Q. Do you have any adjustments to OG&E's capital structure other than debt and equity?

A. Yes. I recommend that the Commission use the current customer deposit interest rate of 2.80% instead of the 4.41% used by OG&E.

B. Return on Equity

1. <u>Current and Expected Future Economic Conditions and their Potential Effect on OG&E going forward</u>

Q. What is your assessment of Dr. Murry's description of the economic environment, OG&E's risk profile, and the interplay between the two?

A. Dr. Murry's description of the economic environment focuses on high energy prices, increased inflation, continuing contraction of the housing and mortgage markets, further credit market write-downs, increasing unemployment, low consumer confidence, and relatively high long-term interest rates. Dr. Murry's assessment of the consequences of the conditions he enumerates is that the "challenges facing the credit and capital markets compound the risks to capital-

[4] Docket 06-070-U, Direct Testimony of Donald A. Murry, p. 12, lines 1-2.

intensive utility companies[,]…rising inflation and rising interest rates erode earnings and adversely affect the cost of a utility's debt and equity[,]…eroding utility margins…[, and] rising inflation and rising interest rates in the longer term increase the risk that common stockholders will not achieve their anticipated returns on investment." [5](Murry, pp. 11)

Much has changed since August 29, 2008, when Dr. Murry wrote his description of the economy and assessment of how the economic environment would affect OG&E. We have experienced the full unveiling of the credit crisis and seen the government bailout of the financial institutions. Fears of inflation have evaporated, with the Federal Open Market Committee stating in its December meeting that "inflationary pressures have diminished appreciably."[6] (This is a very different stance than it took in June, when it said (according to Dr. Murry's testimony[7]), "[a]lthough downside risks to growth remain, they appear to have diminished somewhat, and the upside risks to inflation and inflation expectations have increased.") Commodities prices of all types, including energy, have fallen dramatically. When Murry filed his testimony, a barrel of oil was around $114. As of January 8, 2009, it is $41.91.[8] Long-term treasury bond interest rates have come down with the 10- and 30-year Treasury notes declining from BlueChip forecasts of about 4.2% and 4.8% in Q1 of 2009 (DAM-3) to 2.43% and 3.03%, respectively, as of January 8.[9] However, Long-term corporate bond rates have increased. Moreover, the economy is now officially in recession.

As a result of these changes to the economic environment since August, some of the concerns voiced by Dr. Murry no longer apply. The earnings erosion from inflation is no longer a dominant feature of market conditions, which should

[5] Docket No. 08-103-U, Direct Testimony of Donald R. Murry, p. 11, lines 8-13.

[6] Board of Governors of the Federal Reserve System. Press Release, December 16, 2008. Available: www.federalreserve.gov/newsevents/press/monetary/20081216b.htm.

[7] Docket No. 08-103-U, Direct Testimony of Donald R. Murry, p. 10, lines 13-15.

[8] Reuters. Available: www.reuters.com/finance/commodities/energy

[9] Reuters. Available: www.reuters.com/finance/bonds.

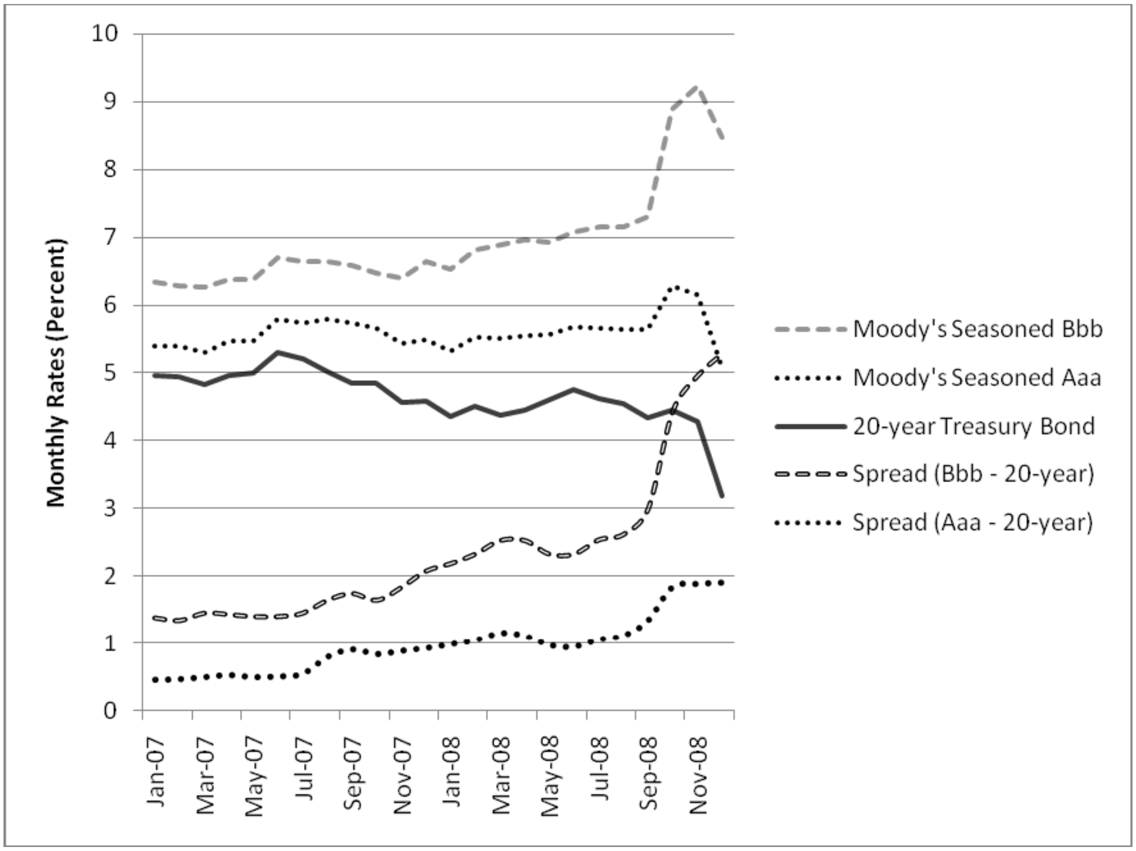
comfort utility investors, especially since Dr. Murry noted in his testimony that "[c]urrent and forecasted long-term interest rates and investors' fears of inflation are the backdrop for electric utility rates of return at this time."[10] Additionally, high energy prices have been pierced—also welcome news to investors.

On the other hand, the interest rate environment is problematic but for a different reason. The decline in long-term treasury bonds results from a continued shakiness in the credit markets and diminished confidence in corporate earnings and solvency. Fear pervades in the markets at every turn. Even the corporate bond market seems risky. Indeed, one of the biggest indicators of a topsy-turvy market is the spread between long-term Federal bond rates and corporate bond rates. The two figures below illustrate this spread (between the 20-year Treasury bond and both the (Moody's 'seasoned') Aaa- and Bbb-rated corporate bonds for the last 10 years (monthly basis).

[10] Direct Testimony of Donald R. Murry, p. 5, lines 7-8.

Figure 1: Comparison of Corporate and Government Bond Yields 1998-2008

Figure 2: Comparison of Corporate and Government Bond Yields 2007-2008



The graphic indicates a spread with the Aaa bonds of almost 2.0% and with the Bbb bonds of about 5.3%. Compare these spreads with the spreads we saw in the last recession (1.7% in October of 2001 for Aaa bonds, and 2.7% in October of 2002 for Bbb bonds). The spread is clearly and substantially higher now (a full 96% higher for Bbb bonds) than it was in the last recession.

The question that a regulatory agency must answer is the appropriate long-term response to this spike in riskiness of corporate debt and the "flight to quality" that reduced interest rates on treasury bonds.

Q. Would you put these conditions into context for this rate case?

A. Yes, I would. First, the conditions in place are, without doubt, highly problematic. It is obvious just from looking at the corporate bond spread (against the Treasury bonds); that the spread is, in fact, a *symptom* that something is out of whack and the system is failing. However, the Federal government has taken aggressive steps to turn the system around, with the recent financial bailout package and the Federal Reserve Board's (Fed) December interest rate cuts to the lowest recorded rates being the most obvious examples of the Federal government's activist stance. The Fed adds that it expects to keep the federal funds rate set at "exceptionally low levels…for some time."[11] And the Federal government gives every indication that it will continue its aggressive interventions. For example, the Federal Reserve is making plans to "circumvent lending-wary banks and target specific markets where credit is jammed."[12] Specifically, it made the following assurances in its December meeting:

> As previously announced, the Federal Reserve will purchase large quantities of agency debt and mortgage-backed securities to provide support to the mortgage and housing markets, and it stands ready to expand its purchases of agency debt and mortgage-backed securities as conditions warrant. The Committee is also evaluating the potential benefits of purchasing longer-term Treasury securities. Early next year, the Federal Reserve will also implement the Term Asset-Backed Securities Loan Facility to facilitate the extension of credit to households and small businesses. The Federal Reserve will continue to consider ways of using its balance sheet to further support credit markets and economic activity.[13]

There are also strong indications that the new presidential administration will push for, and receive, a Federal stimulus package. Current estimates regarding the size of the stimulus package put it in the $800 billion range. For context, $800 billion is about double what the Federal government spent on the interstate

[11] Federal Reserve Board of Governors. Press Release, December 16, 2008. Available: www.federalreserve.gov/newsevents/press/monetary/20081216b.htm

[12] Yahoo! News. "Fed cuts rates to record low" December 16, 2008. Available: news.yahoo.com/s/nm/20081217/bs_nm/us_usa_fed_preview_11

[13] Federal Reserve, December 16, 2008.

highway system, in today's dollars[14]. In any case, it will include the biggest investment in infrastructure since the 1950s[15].

The information contained in such citations illustrates that the government is taking strong and multi-faceted to steps to ease credit and stimulate growth and jobs. It is important to keep in mind as we move through the following analysis that economic conditions we are experiencing right now are part of a cycle that should reverse itself during the rate-effective period; the government interventions only serve to speed up this process and make the recovery more robust.

There is a subtler point, however, and one that rate makers should keenly understand: *if economic and financial conditions persist, or get worse, then **all** companies will have difficulty obtaining capital and making profits for investors*. If the advent of the "doom and gloom" scenario is at hand, OG&E's regulated business will look like a safe haven to investors, compared to the alternatives in other industries with no similar regulatory protection of returns in a howling recession.

Moreover, when the market does return from this recession, OG&E shareholders will earn a tidy return on their outstanding shares as the market gains steam. Essentially OG&E could be paid for "doom and gloom" through a higher than appropriate return on equity but not have to face the regulators to reduce rates when the "doom and gloom" ultimately lifts. .

[14] CBS News. 12/22/08. *Obama Stimulus Package Could Grow To $850 Billion.* Available: www.cbsnews.com/blogs/2008/12/22/politics/politicalhotsheet/entry4683490.shtml

[15] Newsday. 12/08/08. *Economic stimulus package could reach $1.2 Trillion.* Available: www.newsday.com/news/printedition/nation/ny-usstim085956982dec08,0,5280976.story

Q. Please explain how the rest of your analysis is organized in light of your previous comments.

A. The main focus of the rest of my analysis is on providing an alternative to Dr. Murry's calculations and conclusions, as they relate to OG&E specifically. However, I will return to these key issues throughout the rest of the testimony to place Dr. Murry's and my results in context and to support my conclusions and recommendation.

2. Financial and Business Risk

Q. Please review Dr. Murry's assessment of financial risk.

A. Dr. Murry looks at two items in terms of business risk: 1) low common equity ratio, and 2) bond ratings and Value Line "financial strength." In terms of the first item (low common equity), OG&E's ratio is actually considerably higher than comparison companies. This is simply the same mistake I discussed earlier. In terms of terms of the Value Line "financial strength" rating, OGE Energy is A, according to Dr. Murry. Dr. Murry notes that S&P rates OGE Energy bonds as BBB+. But the purpose of this exercise is not to address OGE Energy, but to address OG&E. Fitch rates OG&E's bonds at AA-.[16] OGE Energy bonds are rated lower because of the more risky unregulated Enogex subsidiary (discussed below). These ratings do not indicate financial distress in the least, particularly for the regulated utility.

Q. Please review Dr. Murry's assessment of business risk.

A. Dr. Murry misrepresents the meaning and interpretation of Value Line's "Safety" and "Timeliness" rankings. First, it is important to keep in mind that these are rankings[17], so it is not accurate to state, as Dr. Murry does,[18] that a utility that has

[16] Fitch Ratings. Letter addressed to OGE Energy Corp., December 9, 2008. Provided in response to AG DR 2-79.

[17] Value Line explains its rankings at http://www.valueline.com/vlu/4-vlpage.html .

[18] Docket No. 08-103-U, Direct Testimony of Donald A. Murry, p. 15, lines 1-2.

a ranking of 3 has average metrics for safety and timeliness. When there are only five ranks given to over 1,700 stocks, the most one could say is that a company with a rank of 3 falls somewhere in the "middle of the pack."

In terms of "Safety," specifically, the average of the comparison group is 2.3, whereas OG&E's is 2. Value Line specifically states that 1 and 2 are most suitable for conservative investors, so it is difficult to see how Dr. Murry would indicate that his proxy group and the target utility (OG&E) are highly risky investments.

In terms of "Timeliness," the link between a ranking of how stocks' expected price performs relative to the market is not as clear as Dr. Murry would have us believe[19]. Indeed, Value Line, itself, actually explicitly states:

> Just one word of caution. Stocks ranked 1 for Timeliness are often more volatile than the overall market and tend to have smaller capitalizations (the total value of a company's outstanding shares, calculated by multiplying the number of shares outstanding by the stock's price per share). Conservative investors may want to select stocks that also have high Safety ranks because they are more stable issues.[20]

So, there is nothing necessarily special of about having a high "Timeliness" rank, and indeed, a high timeliness rank can correspond to *high* business risk.

Additionally, Dr. Murry gives a very cursory and general overview of the supposed business risk faced by OG&E and OGE Energy. He "reviewed analysts' reports that noted the business risk facing OG&E and OGE Energy," but gave no references and no reason as to why OGE Energy's business risks, including Enogex and other unregulated activities, are relevant to a discussion of OG&E as a regulated utility. Dr. Murry concludes based on this "review" that "OG&E faces the usual business risks which are familiar to investors in electric utilities in today's markets[—]include[ing] such factors as timely recovery of fuel

[19] *Ibid.*, p. 14, lines 21-26.

[20] Value Line. Available: www.Value Line.com/vlu/4-vlpage.html, click on the number "1" on the Value Line page description.

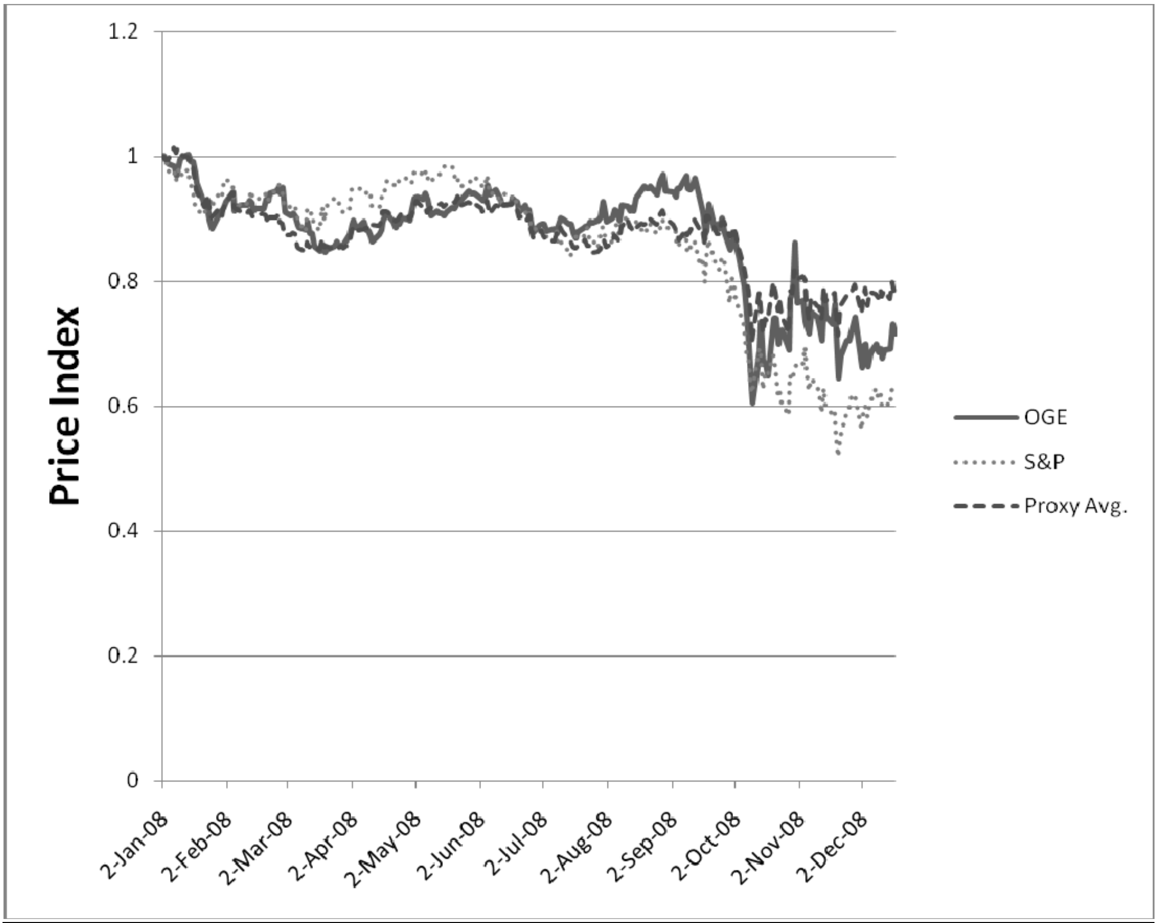
and storm related operating expenses and market pressure on a utility's securities resulting from large capital expenditure programs."[21] There is nothing new in Dr. Murry's argument to suggest that OG&E has unusual risks, and the AA- bond rating from Fitch would suggest otherwise.

Q. What does OGE Energy Corp's stock price and market-to-book ratio say about its financial and business risk?

A. The figure below is an index of OGE Energy's stock price relative to the overall market (S&P 500) and Dr. Murry's comparison group of utility stocks, year-to-date.

[21] Docket No. 08-103-U, Direct Testimony of Donald R. Murry, p. 15, lines 8-12.

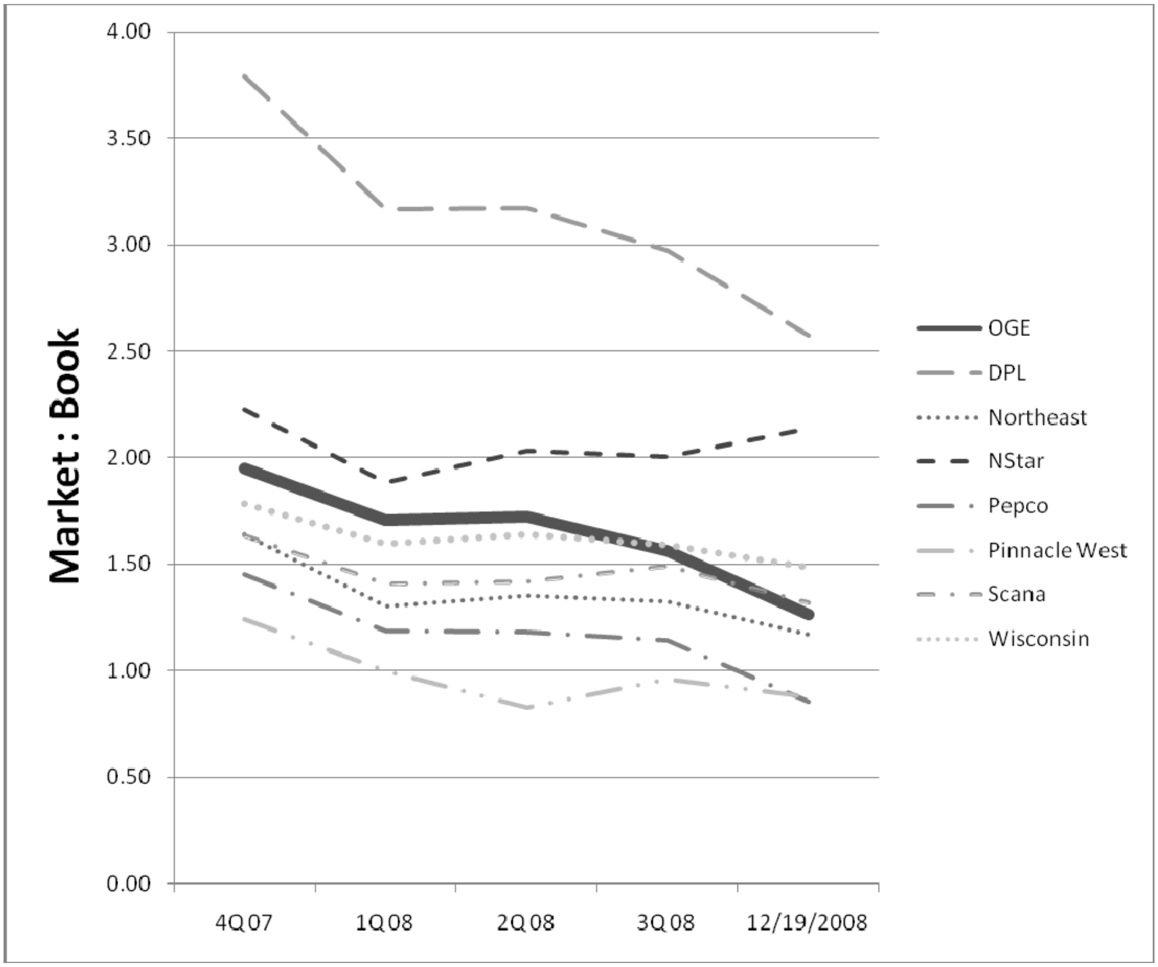
Figure 3: Price Index for OGE Energy, S&P 500, and Proxy Group



Whereas, the S&P 500 had fallen nearly 40% through December 2 of last year, Dr. Murry's proxy group and OGE Energy have fallen 20% and 30 %, respectively, indicating that the market thinks more highly of OG&E and other utility stocks, relative to the broader market. Basically the utilities approximately tracked the broad market through the first major stock market trough on October 10, 2008 but have done considerably better than the market since that time.

A look at the market-to-book ratios of OGE Energy and Dr. Murry's proxy companies shows that the market to book ratios of utilities have been declining during the year 2008 as the stock market has declined. This can be expected, as shown below.

Figure 4: Market-to-book Ratios for OGE Energy and its Proxy Companies



While the ratios of all of these particular companies have fallen over the last year, it is noteworthy that most of the companies (all but Pinnacle West and Pepco) have maintained a market-to-book ratio above 1.0 (so that issuing stock would not dilute the value of existing shares). This is despite the recent erosion of market value of these companies as well as the overall market. On December 19, 2008, OGE Energy was at a ratio of 1.26, not as solid a position as in the past but nevertheless above the dilution point despite recent adverse market and credit conditions.

OG&E's position at 1.26 is particularly significant because it is not a pure play electric utility. While it is the Commission's job to provide appropriate regulation for a regulated electric utility – without reference to other riskier businesses owned by the utility – the activities of the riskier business affiliate of OG&E provides context to what otherwise might appear on the surface to be a low market-to-book ratio.

Q. Will you briefly describe OGE Energy's unregulated activities?

A. OGE Energy's main unregulated activity is operated through its Enogex subsidiary. Enogex is involved in mid-stream services, including well connect, gas gathering and gas processing operations. Like many similar companies, to prepare pipeline quality gas, Enogex produces natural gas liquids (NGLs). NGLs are marketable commodities that typically sell at prices tied to oil. The recent rapid decline in oil prices worsened the position of mid-stream processors at a time when the market was skeptical of any risk.[22]

Enogex extracted and sold 385 million gallons of NGLs in 2007. As such, there is price risk and volatility that affects OGE Energy's market price, increasing the volatility of what would otherwise be a relatively stable company were OG&E the only subsidiary of OGE Energy. OGE Energy says the following in its most recent 10-K statement:

> [A]s a seller of NGLs, Enogex is exposed to commodity price risk associated with downward movements in NGL prices. NGL prices have experienced volatility in recent years in response to changes in the supply and demand for NGLs and market uncertainty.[23]

Although OGE Energy goes on to say that it has taken steps to decrease the effect of such volatility, the fact remains that Enogex injects more risk and volatility into the market price of OGE Energy shares than OG&E would as a sole subsidiary.

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[22] Jason Stephens, "Finding True Value in Master Limited Partnerships" Morningstar.com http://biz.yahoo.com/ms/081226/269266.html?.v=1 UBS Investment Research MLP Insight, 25 November 2008, pp. 3-4.

[23] OGE Energy Corp. 10-K, February 28, 2008 pp. 13.

Indeed, even Fitch Ratings has included comments about the volatility of Enogex in its ratings of OGE Energy. The following were extracted from Fitch Ratings press releases from 2005[24] (for OGE Energy) and 2006 (for OG&E):

> OG&E's credit ratings continue to be supported by the strong financial position and low business risk of its integrated electric utility subsidiary OG&E …, OGE's ratings also take into consideration the higher risk nature of the non-regulated natural gas related activities of Enogex…[25]

> The ratings of the senior notes reflects OG&E's consistently strong operational and financial performance …. The rating also reflects the linkages between OG&E and its parent company and affiliate Enogex.[26]

And whereas the 2006 OG&E rating noted that OG&E senior notes were rated at AA-, Enogex was rated BBB.[27] This shows that Enogex is a drag on the overall safety of OGE Energy, which is the company that investors are actually interested in. This also shows that OG&E, with an AA- rating, is a relatively safe company.

3. <u>Equity Returns from Pension and Decommissioning Funds</u>

Q. Do you have any comments on the analysis of the return on equity (ROE) that Dr. Murry conducted?

A. Yes. I have two general comments. First, the Commission should reject inflated estimates of investors' alleged expectations and unjustified methodologies that inflate the rate of return.

Second, the Commission must not forget that the purpose of this case is to set a return on equity for the <u>regulated</u> operations of an electric and gas utility, and

[24] The AG asked OG&E to provide more current ratings in AG DR 2-79, but none was forthcoming, except for a December 8, 2008 rating for OG&E (not OGE Energy), which did not discuss Enogex at all, so this is the most recent rating we have that discusses Enogex.

[25] ,Provided in response to AG DR 2-79: Fitch Rating of OGE Energy, September 9, 2005.

[26] *Ibid*., Fitch Rating of OGE Energy, January 5, 2006.

[27] *Ibid*.

must prevent higher returns from unregulated activities from influencing its decisions.

Q. Have you developed some additional information to examine the requested return on equity?

A. Yes. It is valuable for the Commission to look beyond the calculation of competing mathematical models when considering the return on equity and look at what utilities and analysts are saying about the stock market when they are **not** trying to convince regulatory commissions to give them a specific return on equity.

There are several sources of this kind of information, including data presented by utilities in their roles as multi-billion-dollar investors in nuclear decommissioning funds and as pension fund managers. In the context of investing in these funds, many utilities are, in fact, trying to convince regulatory commissions to give them more money by providing very low estimates of equity returns on their own investments.

Q. Can you provide an example?

A. Yes, Pacific Gas and Electric Company conducted a survey of 10 actuarial firms, to inform the California PUC that its expectation of an 8.3% equity return and a 7.0% overall return was reasonable. The study showed expectations of average US stock market equity returns of only 7.51% in early 2006. This is one of the lowest market return estimates in recent times. Exhibit WBM-2 contains this document.[28] PG&E has since increased the figure to a still-low 9% equity return.

Q. Have you looked at equity return estimates in the pension field?

A. Yes, I have analyzed the equity return estimates made by actuaries when setting parameters for the rate of return on assets used in calculating funding for pensions and other post retirement benefits (OPEBs).

[28] The survey was provided as a response to Data Request 3-4 of The Utility Reform Network in California PUC Application 05-12-002.

Utility annual reports now contain the data that are used to make these assumptions, including (1) the expected return on assets invested in the pension plan, and (2) the target and actual percentages of debt and equity investments. Even though many of the annual reports do not state expected earnings by asset class, they do provide the overall fund earnings expectation in addition to the allocation the fund managers accord each of the funds' asset classes. OG&E Energy's Securities and Exchange Commission Form 10-K for the year ending December 31, 2007 provides an example.[29] OG&E expects a pension return of 8.50% with an allocation of 61% equity and 37% debt. This is consistent with a return of 10.05% on equity with debt at the discount rate of 6.25%.[30] See Exhibit WBM-3 for a copy of this excerpt, which shows an example of the data that are analyzed.

Q. Does an examination of pension fund returns for other utility companies have any applicability in this case, in particular?

A. Yes. I have calculated the implicit equity return on the pension funds of all of Dr. Murry's comparison companies. One can look at other companies by making the simplifying assumption that the returns on US stocks, international stocks, and real estate are similar over the long run (an assumption that will not have a large impact on the results because of relatively small quantities in international stocks and real estate). Based on this assumption, one can estimate the stock market return that would result with a bond return of, for example, 5% or 6%. In this analysis, for each utility I set the bond return equal to the discount rate that the pension actuary uses (generally the actuary uses the corporate bond rate).[31] This method also calculates the equity risk premium (over corporate debt) for each company by using their own debt return estimates. The estimates of the

[29] OG&E Corporation. SEC Form 10-K Filing for year ending December 31, 2007, Filed on 2/28/08. P. 72 & 77. Available at: ccbn.10kwizard.com/xml/download.php?repo=tenk&ipage=5497096&format=PDF .

[30] These calculations assume that the limited amount of cash earns 3%.

[31] This rate is the pre-mortgage crisis rate.

comparison group's pension actuaries yield an average equity return of 10.4% with an implied risk premium of 4.5%.

Table 2: Pension Return Assumptions for Comparison Companies

Proxy Company	Discount Rate (or fixed income return if stated)	Pension Return	% equity	% debt	% cash if stated	Equity return (debt @ discount rate, cash @ 3%)	10-K Reference
DPL, Inc	0.0575	0.085	0.56	0.33	0.11	11.20%	pp. 85-86
Northeast Utilites	0.058	0.0875	0.71	0.24	0.05	10.15%	pp. 41-42
Nstar	0.0625	0.084	0.68	0.14	0.25	9.96%	pp. 73-74
Pepco	0.06	0.0825	0.58	0.33	0.09	10.34%	pp. 184-185
Pinnacle West	0.059	0.09	0.68	0.25	0.07	10.76%	pp. 104-105
Scana	0.0585	0.09	0.71	0.29	0	10.29%	pp. 66
Wisconsin Electric Power Co.	0.0575	0.085	0.63	0.37	0	10.12%	pp. 89-90
average	**0.0590**	**0.09**	**0.65**	**0.28**	**0.08**	**10.40%**	
risk premium relative to corporate bonds						**4.50%**	

Source: Data taken from utility 2007 10-Ks

In addition, we prepared an "Arkansas Group" of utilities with data from company 10-K statements. The spread in equity return estimates was from 9.22% to 10.0% (average 9.6%). Results are similar to those of the comparison companies.

Table 3: Pension Return Assumptions for Other Arkansas Utilities

	Southwestern Energy (American Electric Power)	Entergy	Empire	Average of Arkansas group
Year	2007	2007	2007	
Equity, Real Estate, etc.	63%	64%	72%	66.27%
Debt	36%	34%	28%	32.73%
Cash	1.0%	2%	0%	1.00%
Return	8.00%	8.50%	8.50%	8.33%
Discount Rate	6.00%	6.00%	5.90%	5.97%
Equity Return (Fixed income @ disc rate)	9.22%	10.0%	9.5%	9.6%
10-K reference	pp. A-27	pp. 145, 149	pp. 104, 105	

Q. Are these implicit estimates of stock market returns by utility pension actuaries consistent with other information provided by utilities in their role as investors?

A. Yes. In their role as managers of decommissioning trust funds, utilities also must project stock and bond market returns to assure the adequacy of funds. We provide some recent examples from filings by Entergy Arkansas, Inc. (EAI) and Southern California Edison Company (Edison).

EAI's workpapers on future decommissioning fund returns filed in the November 1, 2006 Rider 26 update in Docket 87-166-TF show an expected equity return of 7.1% in excess of the CPI inflation rate or an average of 9.3% from 2007-2011. (Exhibit WBM-4).

What is particularly interesting about this estimate is that EAI's analysis of the same historical data from Ibbotson that Dr. Murry uses does not agree with Dr. Murry's testimony. The equity return estimate that Entergy used to estimate decommissioning funding needs is based on a long-run equity return of 7.1% above the *CPI*. Dr. Murry asks the Commission to base OG&E's rate of return (using the CAPM model) on the assumption that the equity return will exceed the *bond return* (which is higher than the CPI) by 7.1%.

As for Edison, its consultant (Global Insight, 2005) provided an arithmetic average estimate of stock market returns of 8.45% over the next 20 years (see Exhibit WBM-5[32]). Even more importantly, Global Insight assumed a yield of 5.85% on the 10-year Treasury bond, which is consistent with a stock market risk premium of only 260 basis points. Similarly, PG&E used a Russell and Associates long-run equity market return estimate of 8.5%. These figures are generally consistent with the equity return estimates that Edison and PG&E used when setting returns for their pension funds.

[32] A portion of the Testimony and Workpapers of Southern California Edison Company in California PUC Application 05-11-008 is excerpted as Exhibit WBM-5.

Q. Please comment on how the expected return of pension and nuclear decommissioning funds relates to the return that prospective investors in utilities "require."

A. Explicitly defining the two terms is helpful:

- Expected return is the weighted-average most likely outcome of an investment in a particular security or portfolio of securities.
- Required return is the minimum return that an investor requires to compensate him for assuming a given level of risk.

Pension and decommissioning funds' stated expectations for returns from equities in which they have invested must be greater than or equal to their required returns for the stock market or the individual stocks they hold. Otherwise, their managers would not have invested in those individual stocks. If they did not like the "expected" return for the market as a whole, the managers would theoretically shift to a portfolio with more fixed-income securities—all the way up to a ratio of 100% if they did not like the expected return of a single available stock. Despite the possibility of more heavily-weighted fixed-income portfolios, these funds vote with their dollars to stay heavily invested in the stock market because the expected return is at least as great as the minimum return that they require to assume the for the level of risk they are assuming. These managers make such decisions notwithstanding returns that are lower than those which Dr. Murry believes are "required."

In essence, fund investors are matching their "requirements" to their "expectations." They simply do not "require" a 12.25% return when the Dr. Murry-supplied federal bond rate was 4.62%, as Dr. Murry recommends. By staying in the market despite their stated pre-financial crisis "expectations" of 10.4% equity returns and 5.9% corporate bond returns, pension funds can provide dollars to retired workers with fewer contributions by corporations and governments. Investors would not require such a return even more so now, given that the federal bond rate has now fallen to 2.87%.[33] Because of the standards written into the Employee Retirement Income Security Act of 1974[34] (ERISA), we can reasonably assume that pension fund managers are providing those returns at a level of risk that they deem prudent. Pension fund behavior in the face of current expectations of relatively low equity returns shows that those low returns meet or exceed their “required return” on equity investments.

We do not need to make a calculation going back to 1926 to figure out the required return (which is what Dr. Murry implicitly does when he uses the Ibbotson data set as inputs into his CAPM calculations). Instead, all we have to do in order to uncover the required return is look at what market participants are actually doing with their own money in the face of current expectations.

Q. Do you have an example of a pension fund’s holdings?

A. Yes. While utilities do not generally publically identify their pension funds’ holdings, the California Public Employees’ Retirement System (CalPERS) does. Of CalPERS’s investments, only 24.4% were in fixed income; the rest were in public equity (59.5%), real estate (8.0%), private equity (6.7%), and cash (1.4%).[35] As of June 30, 2007, it held 13.4% of the total market value of its $100.6 billion in equity holdings in 10 stocks, nine of which are publicly traded; they are shown in the following table.

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[33] December average (Dec. 1, 2008 – Jan. 2, 2009), available: www.federalreserve.gov/releases/h15/data/Business_day/H15_TCMNOM_Y30.txt

[34] ERISA is a Federal law that establishes minimum standards for pension plans in private industry and provides for extensive rules on the federal income tax effects of transactions associated with employee benefit plans.

[35] CalPERS, Annual Investment Report, June 30, 2007. Available: www.calpers.ca.gov/invest/investmentreport-2007/equity/equities.asp?report=domestic_equity .

Table 4: Statistics on CalPERS Top 10 Equity Holdings

Security Holding	Market Value of Shares	% of Total Invested in Equity[a]	Google Beta[b]	ValueLine Beta[c]
Exxon Mobil Corp	2,412,835,545	2.4%	0.61	0.8
General Electric Co	1,841,444,126	1.8%	1.01	0.95
Microsoft Corp	1,429,221,325	1.4%	1.01	0.8
Relational Investors LLP	1,416,163,607	1.4%	NA	NA
AT&T Inc	1,212,935,565	1.2%	0.71	0.8
Citigroup Inc	1,179,817,356	1.2%	1.61	1.45
Bank of America Corp	1,120,531,030	1.1%	1.17	1.4
Pfizer Inc.	976,250,020	1.0%	0.49	0.7
Chevron Corp	969,984,513	1.0%	0.75	0.9
Walmart Stores Inc.	962,728,873	1.0%	0.15	0.65
Total of Top 10 Holdings	**13,521,911,960**	**13.4%**		
Average of Top 10 Holdings	**1,352,191,196**	**1.3%**	**0.71**	**0.88**

[a] Based on total holdings market value on June 30, 2007, which was $100.6 billion.
[b] From Google Finance, Accessed December 30, 2008.
[c] From ValueLine, Accessed December 30, 2008.

It is instructive that the average beta (as calculated by Value Line) of CalPERS's nine largest publicly traded holdings is 0.88—somewhat larger than the average beta Dr. Murry identifies (0.81) for his utility comparison group. The Google-calculated beta of CalPERS's nine largest public holdings averaged 0.71, which is about the same as the current Value Line proxy group beta (0.70, see below) and much larger than the average of Dr. Murry's comparison group betas as calculated by Google, Yahoo!, and Reuters (0.57, see below). Of additional interest, CalPERS holds shares in <u>all</u> of the companies in the utility proxy group.

Q. Do you have any more evidence that supports the use of pension funds as a benchmark for ROE testimony?

A. More evidence supporting the use of pension funds as benchmarks for ROE testimony is available if one inspects the composition of the funds that respected multi-manager investment firms, such as Russell, offer to their ERISA-qualified purchasers (i.e., companies with federally-regulated pension funds). These funds have myriad levels of risk from which to choose. Exhibit WBM-6 shows the funds that the Russell Investment Group offers to its pension fund clients. These funds are available in virtually all risk levels—from target-date and conservative funds to growth funds, small cap funds, and aggressive funds.

Q. Does the Russell Investment Group use the same types of mathematical techniques that Dr. Murry uses to estimate future stock market returns?

A. Yes. In particular, Russell uses a modified discounted cash flow methodology, which it calls the dividend discount model, to derive an equity risk premium. See Exhibit WBM-7[36]. Russell's analysis suggests a stock market return of 9%, composed of 3% inflation, a 3% real return on government bonds, and a 3% equity premium. The real equity return is divided into two components, an average long-term dividend yield of 2.3% and real earnings growth of 3.9% - components that are very similar to those used in a DCF method.

4. <u>Other Information on Stock Market Returns</u>

Q. What information can you bring to bear from other market participants on future stock market returns?

A. There is a considerable amount of information—both in the popular press and the academic literature—suggesting that stock market returns are likely to be less now than in the past.

To give a rather frightening statistic from the current market meltdown, the S&P 500 closed at 903 at the end of December 2008. It was 897 at the end of August, 1997. In eleven years and four months, a buy-and-hold investor in the broad market would have received virtually nothing except the benefits of reinvested dividends.

Q. What information have you found in the popular press addressed to individual investors?

A. In the popular financial press:

- Warren Buffett has been projecting long-term stock market returns in the same range as, or even below, the pension actuaries for over five years,

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[36] This information was provided by Pacific Gas & Electric in Response to TURN/Agnet/UCAN DR 41 in California PUC Application 07-05-003 et al.

In May of 2008, Mr. Buffett stated that he would be happy to generate gains of 10% a year from common stocks over the long-term but questioned whether that will happen. The Berkshire Vice Chairman, Charlie Munger, said that Berkshire Hathaway is "very happy to make money at a rate in the future that's way less than we have in the past and I suggest that you adopt the same attitude."[37] [emphasis added]

This position is consistent with his 2005 letter to Berkshire Hathaway shareholders, discussing the company's stock portfolio, he stated:

> Expect no miracles from our equity portfolio. Though we own major interests in a number of strong, highly-profitable businesses, they are not selling at anything like bargain prices. As a group, they may double in value in ten years. The likelihood is that their per-share earnings, in aggregate, will grow 6-8% per year over the decade and that their stock prices will more or less match that growth. (Their managers, of course, think my expectations are too modest – and I hope they're right.)[38]

Mr. Buffett also made a similar statement in 2003.[39]

- Seeking Alpha finds that from the end of 1968 through October 2008, the dividend-reinvested S&P 500 has earned a 1.5% premium over corporate stocks and just a 1.10% premium over government bonds. Through October 2008, the long-term Treasury bond has *outperformed* stocks since the summer of 1987 and have come in just behind stocks since late 1980 (see Exhibit WBM-8).[40]

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[37] "Buffett Cautions on Long-term Returns". MarketWatch (May 3, 2008). Available: www.marketwatch.com/news/story/buffett-warns-long-term-stock-returns/story.aspx?guid=%7BF74E5BEC-FBFC-4C72-93EE-9DB987BCB1B7%7D

[38] Warren Buffett, Letter to the Shareholders of Berkshire Hathaway, Inc., 2005, page 15. http://www.berkshirehathaway.com/letters/2005ltr.pdf

[39] "Stock Investors Should Expect 6-7 Percent Annual Return, Buffett Says." Bloomberg News Service (May 3, 2003). http://quote.bloomberg.com/apps/news?pid=10000103&sid=a1.neDMy8DEU&refer=us

[40] Seeking Alpha. "What Equity Risk Premium?". Available: www.seekingalpha.com/article/98784-what-equity-risk-premium .

- Exhibit WBM-9 is a July 11, 2005 Fortune magazine article entitled "Get Real About Your Future" where a panel of five experts all suggest returns in the overall equity market of less than 10%.

- Exhibit WBM-10 is an August 29, 2005 Barron's magazine article entitled "Preparing for Low Returns" by Keith Wibel. Mr. Wibel suggests that over the next ten years, S&P 500 returns will be in the vicinity of 6% including dividends (although with a relatively wide range); with historical earnings growth plus dividends, the return would be closer to 8%.

Q. What information has been developed in recent academic literature that relates to the rate of return?

A. In the academic literature, there has been considerable focus on the "risk premium"—the difference in returns between stocks and bonds. This is a key input into the Capital Asset Pricing Model ("CAPM") used to analyze the rate of return.

Arnott and Bernstein's[41] paper (Exhibit WBM-11 specifically states that "observed" excess returns to stocks and the "prospective" or expected risk premium are two different concepts and that the Ibbotson method of looking at historical data does not provide a risk premium. Their paper suggests that stock prices increase in real terms approximately equally to the real per capita GDP growth over the long term.

- "The consensus that a normal risk premium is about 5 percent was shaped by deeply rooted naiveté in the investment community."[42]

[41] Robert D. Arnott and Peter L. Bernstein, "What Risk Premium Is 'Normal'?" Financial Analysts Journal, Vol. 58, No. 2 64-85. (March-April 2002)

[42] Id., p. 81.

- "The observed real stock returns and the excess returns for stocks relative to bonds in the past 75 years have been extraordinary, largely as a result of important nonrecurring developments."[43]

- "The historical average equity risk premium measured relative to 10-year government bonds as the risk premium investors might objectively have expected on their equity investments is about 2.4 percent, half what most investors believe."[44]

Clark and da Silva[45] (Exhibit WBM-12) suggest that the equity risk premium as observed in the marketplace can be decomposed into several components – the dividend yield on stocks, plus the real earnings growth associated with stocks, plus changes in the price/earnings ratio of the market, minus the real return on government bonds. One of those components – changes in the price/earnings ratio – caused a large increase in stock prices through the 1980s and 1990s, but is estimated to be near zero going forward. These analysts therefore estimate a long-run risk premium (without P/E effects) in the vicinity of 4% and cite a number of other studies in the 2.4% to 4.5% range (with one outlier of 7%).

Harvey and Graham have conducted extensive empirical studies of the equity risk premium, by interviewing CFOs of large companies and asking them what they expect as a risk premium.[46] They have found a 10-year equity risk premium (relative to 10-year treasury bonds) declining from about 4.5% in 2000 to the 3.8% range recently (Exhibit WBM-13 contains the most recent report). The average from 2000-2008 is about 3.46%. Graham and Harvey state, based on interviews with CFOs, that it is an expected return over 10 years based on a buy-

[43] Id., p. 80.

[44] Id., p. 81.

[45] Roger G. Clarke and Harindra de Silva, "Reasonable Expectations for the Long-Run U.S. Equity Risk Premium," *Analytic Investors, Risk Management Perspectives* (April, 2003).

[46] John R. Graham and Murry R. Harvey, "The Long Run Equity Risk Premium" Social Science Research Network. Download from papers.ssrn.com/sol3/papers.cfm?abstract_id=795369 and John R. Graham and Murry R. Harvey, "The Equity Risk Premium in January 2008: Evidence from the Global CFO Outlook Survey" (July 22, 2008). Available at SSRN: papers.ssrn.com/sol3/papers.cfm?abstract_id=1162809.

and-hold strategy. The equity risk premium was found to be significantly, though relatively weakly correlated to the real rate of interest, as paid on Treasury Inflation Indexed Notes (not to be confused with nominal rates including inflation). They found the equity risk premium to be higher with higher real rates, rising by about 21 basis points for every 100 basis points in the real rate of interest. Graham and Harvey also asked the CFOs to assess a one-in-ten chance that the market would exceed or fall below a certain level. The **90th percentile return** for the entire market estimated by these CFOs averaged 11.51% from 2002 to the present. The risk premium associated with this 90th percentile return was 6.94%.

Donaldson, Kamstra, and Kramer claim that it is simplistic to estimate the *ex ante* risk premium expected by investors solely using historical data on *ex post* returns without considering other aspects of the data related to market returns. [47] This information specifically includes dividend yields, Sharpe ratios (measuring the riskiness of a portfolio based on the portfolio return minus the risk free rate divided by the standard deviation of portfolio returns), and return volatility. When all of this information is used to simulate the performance of the US markets over the past 50 years, these authors compute an *ex ante* risk premium of 3.5%. Exhibit WBM-14contains the abstract of this paper.

Ivo Welch's 2007 "Welch Survey" (published in 2008)[48] is a survey of 400 finance professors. It indicates a one-year equity premium and a 30-year geometrically-averaged equity premium of between about 5%, or in the interquartile range of between 4% and 6%. Participants in the Welch Survey estimate a 30-year arithmetic equity premium at about 75 basis points above the geometric equivalent, and they estimate that the 30-year geometric expected rate

[47] Donaldson, Glen, Kamstra, Mark J. and Kramer, Lisa A., "Estimating the Equity Premium" (November 2008). Rotman School of Management Working Paper Available at SSRN: http://ssrn.com/abstract=945192

[48] Available at: Welch, Ivo, "The Consensus Estimate for the Equity Premium by Academic Financial Economists in December 2007" (January 2008). Cowles Foundation Discussion Paper No. 1325. Available at SSRN: http://ssrn.com/abstract=285169.

of return on the stock market at about 9%. While higher than some of the other estimates, the arithmetic mean is still 1.35% below Dr. Murry's figure of 7.1%. Please see the 2007 Welch Survey's abstract in Exhibit WBM-15.

As a final example, E. Dimson, P.R. Marsh, M. Stanton, in an article that focuses on how big the equity risk premium has been, historically, and what risk premium investors, corporate managers, and regulators can expect going forward conclude that "(a) plausible, forward-looking risk premium for the world's major markets would be on the order of 3% on a geometric mean basis, while the corresponding arithmetic mean risk premium would be around 5%."[49]

5. <u>The Effect of Unregulated Operations on Proxy Group Earnings</u>

Q. Will you comment further on the need to set a return for regulated operations only?

A. It should be self-evident that the Commission is estimating the rate of return for a regulated utility. OG&E's evidence does not follow this principle adequately, however, and therefore overstates the return on equity required by the utility operations of electric companies.

Dr. Murry's proxy company selection criteria were based on 60% of revenue from electricity operations. Although we understand that in this day and age it is difficult to find a pure regulated utility to which to compare return for return when setting the regulated rate of return, we recommend that the Commission should recognize the impact of unregulated activities on utility earnings growth judgmentally by using the lower end of ranges, particularly when considering "betas" for the capital asset pricing model and when considering the results of the comparable earnings and discounted cash flow (DCF) analysis.

While I do not make specific changes to Dr. Murry's proxy group at this time (because it is so small a sample), I am especially skeptical about the inclusion of

[49] E. Dimson, P.R. Marsh, M. Stanton, "Global Evidence of the Equity Risk Premium", Journal of Applied Corporate Finance, Vol.15, No.4 (2003).

DPL in his proxy group.[50] I may have further comments and explicit adjustments regarding proxy companies after reviewing the Staff's comparison group.

6. <u>Use of the Capital Asset Pricing Model (CAPM) to Analyze the Effect of Lower Equity Returns from Pension and Literature Sources</u>

Q. Will you discuss how the Capital Asset Pricing Model (CAPM) method is implemented to provide some background?

A. The Capital Asset Pricing Model (CAPM) relates the required return to two components – the risk free rate of return, and the market risk premium (amount by which typical stock market returns exceed the risk-free rate of return) – using a measure called "beta" that quantifies the riskiness of the individual stock or investment as compared to the market risk.

Return = Risk Free Rate + Beta X Market Risk Premium

The risk free rate for purposes of setting a utility return is typically a long-term government bond rate. Dr. Murry uses two separate rates, based on two separate set of approaches. One approach examines the historical risk premium of common stock over high-grade corporate bonds, which Dr. Murry estimates to be 6.2%. The other uses a risk-free rate based on long-term government bonds (culled from recent markets), which Dr. Murry estimates to be 4.62%. I do not subscribe to the use of corporate bonds as a substitute for the risk-free rate. While I can understand not wanting to use the customary short-term government bond, it is a curious choice to apply corporate bonds, given the highly risk averse environment that is pushing the yield on corporate bonds up. Dr. Murry suggests that long-term government bonds are not a good substitute for short-term bonds in developing the risk-free rate because of the "flight to quality" situation that is the current economic situation engenders. But with the use of the corporate bond as a

[50] Including DPL in proxy groups is a mistake that many rate of return analysts make because the utility has not placed its generating units operating in Ohio's deregulated market in a separate affiliate from assets under rate of return regulation. Therefore, the screening mechanisms used by Dr. Murry and by Staff will often erroneously treat DPL as a utility even though most of its profits come from unregulated generation.

risk-free proxy, one has an equally-powerful "flight from risk" phenomenon. For the moment, I will use the long-term government bond (20-year Treasury bond, which averaged 2.87% during the 30 days ending January 2, 2009) in order to illustrate the difficulty these market conditions present.

Besides the decision to use corporate bonds as the "risk-free rate," the "market risk premium" is the other of the more contentious items, here. Dr. Murry has used two different methods. One is the "size-adjusted" CAPM, in which Dr. Murry uses a historical risk premium, calculated by Ibbotson, of 7.1% based on stock and bond returns data starting in 1926. I believe that the risk premium is considerably lower than this historical risk premium would indicate, based on the information from pension fund actuaries and the literature cited above.

Additionally, the very notion that Dr. Murry's calculations need size adjustment (of 1.02%) to reflect that small firms tend to have higher returns than larger firms for the same beta does not make sense given the type of firms—regulated—that we are talking about. I do not dispute as a matter of empirical analysis or financial theory that such an adjustment might be reasonable when examining <u>unregulated</u> firms – where size and risk have some relationship and where investment analysts' coverage of small firms is more limited. However, I do not believe that such an adjustment should be applied to a regulated utility. A regulated utility generally faces risks that are less than those of an unregulated "small" company, and the market understands that issue. Indeed, as we noted above, Value Line ranked OGE Energy's stock "Safety" as a '2', which indicates that it should be in the conservative investor's portfolio, and the Fitch rating service OG&E's utility bonds as AA-.

In Dr. Murry's second application of CAPM uses historical returns of 14.7%—again, presumably using Ibbotson's data that date back to 1926—and then calculates a risk premium of 8.5% from that historical rate using the corporate bond rate 6.2% of to arrive at a risk premium.

"Beta," or the risk of individual stock or stocks, is calculated by comparing the returns on individual stocks to the market return over a period of time. A beta of less than one indicates that a stock will tend to increase at a rate that is less than the market return when the market goes up and decrease at a rate that is less than the market decline when it drops. Conversely, a beta greater than one means that a stock will increase or decrease more rapidly than the rate at which an increasing or decreasing market would. Again, the greater beta is from one, the greater this effect.

Theoretically, beta is the portion of systematic or non-diversifiable risk associated with a given stock. The source of "beta" traditionally used in utility rate cases comes from Value Line, which has made such calculations for over 30 years. However, new sources of beta, calculated in different ways, have become available in the Internet age (from Google, Yahoo!, and Reuters). These betas at the moment are considerably lower than Value Line betas.

Q. What methods does Dr. Murry use to estimate the historical "risk premium" for the CAPM?

A. Both of Dr. Murry's CAPM calculations rely on long-run historical estimates of *ex post* returns, based on the arithmetic mean of data from 1926-2007 from Schedule DAM-22 of his direct testimony. [51] The first (7.1%) comes directly from Ibbotson. The second is derived by taking some supposedly-supportable total market return of 14.70% (presumably from Ibbotson, based on the footnote to Exhibit DAM-22) and subtracting out a particular corporate bond rate (6.2%) to arrive at a risk premium of 8.5%. The point is that both of these methods rely on Ibbotson, which typically uses a data set that starts in 1926.

Q. Will you evaluate Dr. Murry's historical estimating method for computing the historical "equity risk premium" used in his CAPM analysis?

[51] Dr. Murry uses the Ibbotson Associates 2008 SBBI Yearbook: Valuation Edition Market Total Returns; Ibbotson market data typically begins with 1926; we make the assumption that Dr. Murry's data follows that pattern.

A. A constant risk premium can only be justified from the narrow perspective of pure statistics. Because returns on stocks and bonds are volatile from year to year, it is impossible to discern trends in highly aggregated data on returns using standard statistical techniques without analyzing other information (for example, the information analyzed in a more sophisticated way by Donaldson, Kamstra, and Kramer, provided in Exhibit WBM-14. However, the statistical perspective is a narrow one. It states that statistical methods cannot discern a trend in data, not that such a trend is absent.

While investors do not necessarily believe that every year will be economically rosy, by using data beginning from 1926, Dr. Murry is assuming that investors today give significant weight to a recurrence of the economic conditions of 60-80 years ago (the Great Depression, World War II, and Federal Reserve Board monetary policy designed to keep interest rates down for the purpose of financing government war debt cheaply).[52] The Federal Reserve Board itself recently rejected use of data all the way back to 1927 when calculating the return on equity capital used to estimate returns on Federal Reserve Bank priced services. It made the determination to use only 40 years of historical data, not 80 years.[53]

As discussed above, considerable amounts of the academic literature are identifying a risk premium in the range of 3.5 to 4%. Corporate CFOs are identifying a risk premium of 3.6% and are stating that a risk premium above 7.21% would only be observed with a 10% probability. Most utilities' own pension actuaries and decommissioning fund managers are showing 9-10% stock market returns with fixed income returns in the 6% range.

In addition, as we said above, we are firm in our position that if current economic and financial conditions continue or worsen, then investors are going to be lucky to get a return on their capital anywhere near what regulated utilities are allowed even allowing that these conditions are currently making capital more expensive.

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[52] Donaldson, Kamstra, and Kramer, op. cit., p. 9 stated that "modern monetary policy" began in 1951.

[53] 70 Federal Register, 60341-60347, October 17, 2005. Notice in Docket OP-1229.

Therefore, Dr. Murry's estimate of the long run risk premium—whether it be 7.1% or 8.5%—is not a reasonable predictor of investors' expectations or requirements over the long-term, regardless of long-ago history or statistical niceties or the difficult climate we presently face—granting of course that we currently have special circumstances with the current financial and economic climate that may push short-term risk-premiums higher than is appropriate for the long-term.

Q. Have you prepared any comparisons of historical stock market returns, returns on utility stocks, and bond returns over a long period of time (i.e., a period of time that could be used in a historical CAPM)?

A. Yes. While I have deliberately not gone all the way back to 1926, I have prepared a comparison of returns for electric utilities, gas utilities, the S&P 500 and bonds (using electric and gas utility return and bond return data presented by Dr. Roger Morin)[54] and S&P 500 data developed by Dr. James Vander Weide, a utility witness in a recent Pacific Gas and Electric Company cost of capital case.

I used the period 1955-2001. I purposely chose the beginning of the period to start after the end of the Korean War and the ensuing 1954 recession, as well as after the beginning of "modern monetary policy." The period of time that includes the Great Depression and World War II and its aftermath does <u>not</u> reflect conditions that current investors believe hold today or are likely to recur in the future, even though reaching farther back in history produces higher risk premium numbers that utility rate of return analysts like to use. The end of the period

[54] Electric utility and bond return from Exhibit RAM-3 of his testimony in Arkansas PSC Docket 06-101-U (Entergy Arkansas), available: http://www.apscservices.info/PDF/06/06-101-u_16_1.pdf; gas utility return from Exhibit RAM-3 of Arkansas PSC Docket 04-176-U (an Arkansas Western Gas Company rate case), available: http://www.apscservices.info/efilings/Docket_Search_Documents.asp?Docket=04%2D176%2DU&DocNumVal=9.

(2001) was the last year for which Dr. Morin presented data in his recent rate case filings.[55]

Table 5: Returns and Risk Premiums for Electric Utilities, Gas Utilities, the S&P 500, and Long-Term Treasury Bonds

	1955-2001	1960-2001	1967-2001	1983-2001	1955-1966	1967-1982
S&P 500 return	11.86%	11.77%	12.31%	15.33%	10.57%	8.73%
Electric Utility Return	11.53%	11.47%	11.53%	15.30%	11.52%	7.05%
Gas Utility return	12.16%	11.79%	12.25%	15.07%	11.91%	8.91%
Bond Return	6.33%	7.27%	7.90%	11.17%	1.73%	4.02%
Electric Utility risk premium	5.20%	4.20%	3.62%	4.13%	9.79%	3.03%
Gas Utility risk premium	5.84%	4.52%	4.35%	3.89%	10.18%	4.89%
S&P 500 risk premium	5.54%	4.51%	4.41%	4.15%	8.84%	4.71%
Electric utility return as % of S&P 500	97.1%	97.4%	93.6%	99.8%	109.0%	80.8%
Gas utility return as % of S&P 500	102.5%	100.1%	99.5%	98.3%	112.7%	102.1%

Over the 46 years from 1955-2001, the S&P 500 had a return that averaged 5.54% above long-term treasury bonds. This is approximately 156 basis points below the risk premium derived by Ibbotson (7.1%), and about 300 basis points below the risk premium that Dr. Murry derived using the total return on bonds for 1926-2007, vis-à-vis Dr. Murry's corporate bond rate (6.20%). Using 40 years of data gives a risk premium of about 4.5% for the S&P 500.

Q. Will you compare the returns on utility stocks versus the S&P 500 in the Table above?

A. The rest of this chart is even more interesting than the risk premium estimate. Over the 46 years ending in 2001, electric utilities underperformed the S&P 500 by only 32 basis points (2.9%) despite being considerably less risky (with betas less than 1). Over sub-periods, the return ranged from 81% to 109% of the S&P 500. The lowest return was experienced in the 1967-1982 period, a time when electric utilities in particular faced depressed prices due to the lack of fuel adjustment clauses in the 1974 oil shock coupled with dramatic reductions in

[55] In Docket No. 06-101-U Dr. Morin responded to a data request by the Attorney General that the data series on which he relied to do this analysis were discontinued after 2001. It is also difficult to update this analysis because the prevalence of deregulation this decade means that fewer and fewer utilities are close to being purely regulated. However, the point regarding the bias that pre-modern monetary policy returns (those that include the Depression, WWII, and the Korean War) introduce to 2009 *ex ante* expectations remains robust and relevant to our discussion regardless of the lack of a dataset that does not go past 2001.

demand growth, massive capital spending programs, and burgeoning interest rates. In the 1983-2001 period, electric utilities provided a return virtually identical to the S&P 500.

Gas utilities had even better performance. Gas utilities <u>outperformed</u> the S&P 500 by 30 basis points (2.5%) despite being less risky (with betas less than 1 over the vast portion of the historical period). Over sub-periods, the return ranged from 98% to 113% of the S&P 500 – a return virtually identical to the market as a whole.

This finding needs to be compared with a principle cited in key court cases on rate of return—that the authorized return on common equity should be the same as returns on investments in other firms with similar risks. For a group of less risky, low-beta regulated utility stocks to perform equivalent to the market as whole violates this risk principle.

This may even suggest there has been some kind of long term "free lunch" for utility investors, which the market may not yet have fully recognized. The "free lunch" may potentially arise from the circular nature of the setting of utility returns – high returns in the past beget requests by utilities for high returns in the future, which in turn begets stock performance equal to the S&P 500 over the long run with considerably less risk (particularly in the past) than the S&P 500.

Q. Have any recent tax changes affected utilities' cost of capital?

A. Yes. The new lower tax rates on both dividends and capital gains have increased the after-tax returns for at least some investors in the market, which all else being equal, should lower the cost of equity capital relative to the period before 2003.

Q. Are you providing any additional quantitative information as a check on the information presented by Dr. Murry?

A. Yes. We provide CAPM calculations over a range of market assumptions. Before pursuing these calculations in detail, however, it is first useful to focus on the choice Dr. Murry made for beta. As seen in Table 6, Dr. Murry arrives at his beta of 0.81 by averaging the Value Line-sourced betas from his proxy group. First, this figure requires updating. The average of the current (as of January 5th, 2009) Value Line beta estimate for Dr. Murry's comparison group is 0.7. Table 6 also contains the average beta from a group of alternative sources, which comprise Google Finance, Yahoo! Finance, and Reuters (we initial this group with GYR)[56]. The GYR group of beta sources contains raw beta estimates for the comparison group that average 0.57, which is considerably lower than the 0.70 average that Value Line offers (from November 28, 2008) or the one that Dr. Murry supplied (from Value Line at the time of his filing) of 0.81. Value Line adjusts its betas upward if they are less than one. I applied an upward adjustment, as well, using the Empirical Capital Asset Pricing Model (ECAPM) on the GYR raw betas with an average result of 0.68. (I do not support Empirical CAPM as a matter of theory but use it here for the purpose of stating the Value Line and GYR results on a roughly comparable basis).

Table 6: Alternative Betas for Dr. Murry's Comparison Group

Company	Murry	ValueLine[1]	Alternative Sources of Beta[2] Google Finance	Yahoo! Finance	Reuters	Average of Alternative Sources	Average of Alternative Sources with ECAPM
DPL, Inc.	0.8	0.65	0.65	0.57	0.6	0.61	0.71
Northeast Utilities	0.75	0.75	0.67	0.71	0.68	0.69	0.77
NStar	0.8	0.7	0.31	0.27	0.34	0.31	0.48
Pepco Holdings	0.9	0.75	0.80	0.8	0.79	0.80	0.85
Pinnacle West	0.8	0.7	0.54	0.55	0.57	0.55	0.67
Scana	0.85	0.7	0.50	0.63	0.61	0.58	0.69
Wisconsin Electric	0.8	0.65	0.46	0.47	0.47	0.47	0.60
Average	**0.81**	**0.70**	**0.56**	**0.57**	**0.58**	**0.57**	**0.68**

[1] ValueLine, January 5, 2009.
[2] Accessed on the sources' respective Websites on December 19, 2008.

The average of the ECAPM-adjusted GYR beta is very close to (yet still smaller than) the current beta calculated by Value Line. This is a change from a year ago when there was a wider divergence between the two data sources. The unadjusted beta as calculated by the GYR group is quite a bit smaller than the one

[56] Google Finance, Yahoo! Finance, Reuters, Value Line, E-Trade, and presumably a number of other financial services all have their own betas which differ by time periods and whether adjustment factors are used.

Value Line calculates, suggesting that there is less risk for stocks in the comparison group if ECAPM is not used.

Q. Do low Treasury bond rates present a challenge to classical CAPM analysis?

A. Yes, low Treasury bond rate (with a large spread between Treasuries and corporate bonds) is an indicator of relatively high risk as discussed above, but the CAPM model is not specifically designed to capture that risk. The very low current Treasury bond rate presents this problem. On the other hand, using corporate bond rates, as Dr. Murry has done in his alternative CAPM analysis, and then adding on figures based on historic long-term stock-bond differentials is also wrong under current market conditions for the opposite reason. It does not reflect the fact that it is virtually impossible to obtain the long-term average differential return between stocks and bonds in a market that is subject to the present short-term risk shown by the current differential between treasury and corporate bonds.

Q. Have you performed CAPM calculations over a range of market return assumptions?

A. Yes. Table 7 depicts our CAPM calculations over a range of market return assumptions, using both Dr. Murry's risk-free rate (4.62%) and the current risk-free rate (2.78%) (in all cases except Case 8, the California decommissioning fund estimate, where the higher risk-free rate contained in that analysis was used), and a selection of beta choices from Table 6.

Table 7: Range of Capital Asset Pricing Method Results

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Average
Risk-free rate (Murry)	4.62%	4.62%	4.62%	4.62%	4.62%	4.62%	5.83%	
Risk-free rate (current[1])	2.87%	2.87%	2.87%	2.87%	2.87%	2.87%	5.83%	
Market equity return		10.40%	9.30%	10.39%			8.45%	
Risk premium (over Murry risk-free rate, 4.62%)	5.54%	5.78%	4.68%	5.77%	4.00%	3.59%	2.62%	
Risk premium (over current risk-free rate, 2.87%)	5.54%	7.53%	6.43%	7.52%	4.00%	3.59%	2.62%	
Return on equity w/ Murry beta (0.81) & Murry risk-free rate (4.26%)	9.13%	9.33%	8.43%	9.32%	7.88%	7.54%	7.96%	8.51%
Return on equiity w/ current beta (0.70[1]) & Murry risk-free rate (4.62%)	8.50%	8.67%	7.90%	8.66%	7.42%	7.13%	7.66%	7.99%
Return on equiity w/ current beta (0.70[2]) & current risk-free rate (2.87%)	6.75%	8.14%	7.37%	8.13%	5.67%	5.38%	7.66%	7.02%
Return on equiity w/ current beta (0.68[3]) & current risk-free rate (2.87%)	6.63%	7.98%	7.23%	7.97%	5.58%	5.30%	7.61%	6.90%
Return on equiity w/ current beta (0.57[4]) & current risk-free rate (2.87%)	6.03%	7.17%	6.54%	7.16%	5.15%	4.92%	7.33%	6.33%

Case 1 -Historical Risk Premium - 1955-2001 average S&P risk premium
Case 2 - Pension equity returns 7 comparison electricity companies
Case 3 - Entergy nuclear decommissioning return - geometric mean with current inflation
Case 4 - Entergy nuclear decommissioning return - approximate arithmetic mean with current inflation *
Case 5 - Clark and da Silva risk premium estimate
Case 6 - Graham and Harvey average risk premium 2000-2005 (close to Donaldson, Kamstra and Kramer estimate)
Case 7 - California utilities' equity and debt market estimates (decommissioning funds)

* added 109 basis points for difference between geometric and arithmetic means for S&P-500 minus GDP implicit price deflator for 1955-2001. Note that I do not accept the contention that the arithmetic mean is the only appropriate measurement of equity returns but am providing this figure to show the impact.

[1] 20-year Treasury Bond rate, average from Dec. 1, 2008 - Jan 2, 2009 (US Federal Reserve, accessed: www.federalreserve.gov/releases/h15/data/Business_day/H15_TCMNOM_Y30.txt on December 5th 2009)

[2] Value Line's beta (accessed January 5, 2008).

[3] Average of Google Finance, Yahoo! Finance, and Reuters <u>betas with ECAPM applied</u>; raw beta estimates come from respective sources' Websites, accessed on December 19, 2008.

[4] Average of Google Finance, Yahoo! Finance, and Reuters <u>raw betas</u> (accessed December 19, 2008).

The average returns in Table 8 range widely, from 6.33% (using GYR beta and current risk-free rate) to 8.51% (using the Dr. Murry's beta and risk-free rate); the returns of the individual cases range from 4.92% to 9.33%, with Dr. Murry's beta and risk-free rate causing larger values than current betas and rates.

While I do not think that returns on the high end of this range are unreasonable, the returns on the low end are certainly unreasonable. I point them out, however, to illustrate two things. First, it is important to remember the effects of using the correct inputs (such as the correct beta and risk-free rates). Second, the recession is responsible for creating the low return numbers by creating the low risk-free rate. But, as I stated above, if we are truly going to realize these returns going forward, then investors are going to be scrambling to realize returns comparable to those on the high end of this CAPM range for comparably risky assets.

I would also point out that **the highest possible number calculated using the highest risk premium and highest beta (9.33%) is already below the current authorized rate of return for OG&E (10%)**. Also, figures at or below 9% are not unheard of, and have previously been adopted. The Alberta Energy and Utilities Board's current formula for setting the utility cost of capital, based on a risk premium method, which started out at 9.6% in 2004, was indexed at 8.51% in 2007 and 8.75% in 2008. See Exhibit WBM-16. Indeed, a figure of 7.49% would flow from the Alberta formula applied to the current 2.87% risk-free rate.

I would also note that the betas for electric utilities have been declining recently from about 0.9 in 2007 to 0.7 now. All else being equal such a decline in beta should cause the rate of return to decline.

In sum, my CAPM results show that Dr. Murry's back-to-1926 and Value-Line-Pollyanna-economy methods are unreasonable, and that a CAPM analysis supports considerably lower numbers than have been adopted, and that a reasonable CAPM estimate taking all of the information into account is at or below 9%.

7. Discounted Cash Flow Models

Q. Is there a problem with the Discounted Cash Flow model that Dr. Murry used?

A. There is a problem with the DCF models inasmuch as Dr. Murry relies on forward-looking forecasts of future cash flows. These forecasts are based on market analysts' shorter-term, and less fundamentally based, approaches. Given the current down market, analysts predictions are weighed heavily with expectations the market will turn around, which produces larger growth estimates of dividends and earnings than is sustainable over the long-term. The market analysts never predicted the original drop when calculating rate of return, but they do not hesitate to use the abnormally high rebound from that drop.

Conversely, the fundamental, or "earnings retention", method measures the sustainable increase in book value (related to ROE for an electric utility under rate base regulation), which is a way of indicating a utility's long-run ability to increase its earnings, and hence dividends. It is based on the earned rate of return, multiplied by the retention ratio (the percentage of earnings not paid out in dividends), plus an adder for the accretion to book value that arises when a utility finances construction by selling stock at a price above book value. This fundamentals method would take out the short-term volatility of this down market, giving a more realistic view of what we could expect of the long-term.

Additionally, I would note that current market conditions and the drop in utility stock prices have caused the dividend yield of utility stocks to increase significantly. To the extent that the credit crisis and the associated risk aversion is ameliorated, one could expect the dividend yield component of the DCF method to fall over the next year or two.

Therefore, this discussion and as well as the conclusions that can be drawn from the pension fund and CAPM discussions, above, the Commission should give little weight to Dr. Murry's stated "relevant range" of 11.17%-13.70%.

Q. Do you any problems with how Dr. Murry interpreted his DCF results?

A. Yes. Dr. Murry's results in Schedules DAM-17, DAM-18, and DAM-19 have results on the low end of the calculated range of 10.03%, 11.25% and 10.44%, and yet Dr. Murry only states that the relevant range is 11.17%-13.7%, which is merely the lowest and highest of the high end of the range in each DCF calculation.

8. <u>ROEs approved by Other Commissions</u>

Q. Are there other commissions that have approved rates of return that are on the order of what your results suggest?

A. Yes, in addition to the Alberta decision that we provided above, there are a number of state commissions in the U.S. that have approved ROEs of less than 10% in recent years. (These are meant to be illustrative; we do not mean to imply that other examples do not exist.)

- <u>In 2008</u>, the New York Public Service Commission approved a return of 9.1% for electric distribution service (Consolidated Edison Company of New York, Inc., Case 07-E-0523[57]). In 2006, it approved 9.8% (Orange and Rockland Case 05-G-1494),[58] and 9.6% (Central Hudson, Cases 05-E-0934 & 05-G-0935, and St. Lawrence Gas, Case 05-G-1635[59]).

[57] New York Public Service Commission, Order Establishing Rates for Electric Service in Case 07-E-0523 (March 25, 2008), slip op. p. 126. http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/27823125130A3E38852574170067DDB4/$File/301_07e0523ORDER_FINAL.pdf?OpenElement

[58] New York Public Service Commission, Order Making Temporary Rates Subject to Refund in Case 06-E-1433—Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

[59] New York Public Service Commission. Press Release on 11/8/06: PSC Approves Three-year Rate Plan for St. Lawrence Gas. Available: http://www.stlawrencegas.com/pressrel/Press%20Release%20-%20November%202006.pdf .

- The New Mexico Public Regulation Commission approved an ROE of 9.5% in June, 2007 (Public Service Company of New Mexico)[60].
- The New Hampshire Public Utilities Commission approved a rate of return of 9.63% on generation (Public Service Company of New Hampshire, Docket DE 04-177)[61] in 2005.

In sum, other commissions have authorized single-digit rates of return in the recent past. We grant that this past does not include the current financial meltdown, but has we have stated above, it if financial and economic conditions stay as they are, any guaranteed return in the high single-digits will be welcome news to potential and current investors.

C. Summary of Rate of Return

Q. Will you summarize your position regarding the rate of return?

A. The requested 12.25 % return on equity for a utility like OG&E is simply not reasonable under the circumstances.

1. OG&E itself expects that the broad equity market will earn 10.05% when making pension fund projections.
2. The average equity return expected by the pension actuaries of the 7 utilities identified by Dr. Murry as a comparison group to OG&E is 10.4%, given an average discount rate (high grade long-term corporate bond rate) of 5.9%.
3. The 90th percentile return for the entire market from Graham and Harvey's CFO survey averaged 11.5% from 2002 to the present. The CFOs' average expected return was around 8% (risk premium of 3.5%).

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[60] New Mexico Public Regulation Commission. Press Release on 6/29/07: PRC Reduces Proposed PNM Rate Hike. Available: http://www.nmprc.state.nm.us/news/pdf/062907pnm_ratehick.pdf .

[61] New Hampshire Public Utilities Commission. Order No. 24,473, Transition and Default Service Rates, Order Following Hearing Regarding Return on Equity. The order indicated that the appropriate rate of return on a diversified utility would be 9.42% and added 21 basis points for risks of regulated generation.

4. Other academic literature, as well as the analysis by the Russell Investment Group suggests a risk premium of 3% to 5%, which corresponds to an overall stock market return below 10%.

5. Historical data that does not reach back to the Depression and World War II supports equity returns of 10% or less.

In addition to these factors, we must look carefully at the context. Current market conditions are both abnormal and unsustainable and also cause models typically used when analyzing the rate of return to yield results that are unreasonable or difficult to interpret.

The spread between corporate bonds and government bonds has been increasing, as investors' appetite for risk is reduced. The very low rate on government bonds renders some of the results of a classical capital asset pricing model (CAPM) formulation to be unrepresentative of anything except the results that would be likely to occur in a deep credit-based recession (returns in the 7-8% range).

The DCF model results have the opposite infirmity under current market conditions that could tend to overstate long-term equity returns: (1) unusually high current stock dividend yields that are (2) coupled (particularly in Dr. Murry's analysis) with growth estimates that are unsustainable long-term and are consistent with falling dividend yields in the future.

Either this risk aversion (marked by large spreads between government and corporate bonds) will continue for a significant period of time, or it will return to more normal levels.

If the spread returns to more normal levels, it would be a mistake to give utilities a rate of return that could be in place for several years on the basis of transitory market conditions.

If, on the other hand, the outsized spreads between government and corporate bonds continues, the resulting credit crisis (spread far beyond the housing sector) will contribute to an extremely deep recession. Under such recessionary conditions, investors might *desire* high returns to compensate for risks, but those high returns will simply not be realized. In essence, a high rate of return does not flow from a prediction of a continuing high risk premium. The credit conditions and real economic conditions that would flow from forecasting a continued high risk premium would ensure that stock market investors are unlikely to realize the returns that they would allegedly "require". Under these conditions, utilities would be a relatively safe haven compared to many other investment choices and should be priced accordingly with lower returns than are in place today.

While we do not know what will happen, we can state that using current dysfunctional market conditions as the basis for adopting large upward changes to investors' required returns on utility equity is likely to be the wrong answer – either because the conditions generating such "required" returns will be transitory or because, if not transitory, the conditions generating such "required" returns will make it impossible for the returns to be achieved in the real world.

Faced with a highly uncertain economy and a situation where standard rate of return models do not provide terribly good forecasts, I recommend that the Commission simply stay the course. As noted above, a higher return is not reasonably justifiable based on an appeal to current market conditions, though I might consider raising the ROE if necessary in a specific case to keep a utility market-to-book ratio at or a little above 1.0 to maintain some financing flexibility (a concern that OG&E does not face). A lower return could be justified by the type of analysis that is presented in this testimony *under normal economic conditions;* normally, a CAPM return for utilities between 8.8% and 9.5% range is generally reasonable and would support the low end of a typical DCF-based analysis.

However, in a period of financial and credit uncertainty verging on the irrational, while I do not recommend an increase to the ROE, the Commission should also not reduce the rate of return below current levels, as it could exacerbate fear in credit markets. I therefore recommend continuation of the 10% return on equity for OG&E.

Q. Will you confirm the rate of return that you are recommending?

A. Given financial market and economic conditions, I am recommending that the Commission leave OG&E's ROE at the currently approved 10%.

Q. Have you prepared a summary showing your proposed rate of return on rate base?

A. Yes, it is provided below, including the AG's capital structure, ROE and customer deposit rate.

Table 8: AG's Capital Structure and Rate of Return

	Amount	Capital Ratio	Rate	Weighted Cost	Tax Gross-Up
Long Term Debt	$ 1,779,705,083	41.44%	6.40%	2.65%	2.65%
Pref Stk	$ -	0.00%	0.00%	0.00%	0.00%
Common Equity	$ 1,456,122,340	33.91%	10.00%	3.39%	5.58%
Accumulated Def Inc Taxes	$ 644,688,707	15.01%	0.00%	0.00%	0.00%
Pre 1971 ADITC	$ -	0.00%	0.00%	0.00%	0.00%
Post 1970 ADITC	$ 21,970,123	0.51%			
Equity	$ 9,886,555	0.23%	10.00%	0.02%	0.03%
Long-Term Debt	$ 12,083,568	0.28%	6.40%	0.02%	0.02%
Short-Term Debt	$ -	0.00%			
Customer Deposits	$ 53,633,284	1.25%	2.80%	0.03%	0.03%
Short Term/Interim Debt	$ -	0.00%	5.25%	0.00%	0.00%
Cur, Accrued and Other Liab	$ 338,577,290	7.88%	0.00%	0.00%	0.00%
	$ 4,294,696,827	100.00%		6.11%	8.31%
Long-term debt + equity + short-term debt	$ 3,235,061,720				
Interest synchronization percentage				2.70%	

Q. Will you compare your rate of return with OG&E's?

A. OG&E proposes a rate of return of 7.38% before tax and 10.72% after tax. The differences between us can be disaggregated into 47 basis points before tax (112 basis points after tax) for differences in the capital structure at OG&E's 12.25% rate of return, 77 basis points before tax (126 basis points after tax) for the AG's 10.0% rate of return; and 3 basis points (before and after tax) for the lower customer deposit rate.

With OG&E's requested rate base, the Attorney General's capital structure and rate of return reduce the required rate increase by $9,315,000 or 35.3% of the proposed increase.

III. Expenses and Rate Base

A. Incentive Compensation

1. Short-Term Incentive Programs

Q. Have you analyzed OG&E's short-term incentive programs?

A. Yes. Based on information contained in AG DR 2-21 I have divided the costs into three general categories:

1. Corporate financial costs include earnings per share and O&M and capital spending targets at the utility (and unregulated earnings per share for the CEO).

2. Departmental financial costs include departmental budgets and spending levels. Note that OG&E specifically treats worker safety as a financial issue, not a benefit of its own. In its discussion of safety, OG&E states that benefits to customers are provided because workplace safety results in "Control of employee and company health expenses and Worker's Compensation costs."[62]

3. All other non-financial metrics (e.g., customer service, accuracy in transmission switching, etc., as well as metrics that affect fuel costs – where ratepayers receive 100% of benefits through fuel adjustment riders).

[62] OG&E Response to AG DR 2-21, Attachment 3, "2007 pg 1" worksheet, see cell AC193 for example.

The results are summarized in the table below with disaggregated data taken from AG DR 2-21.[63]

Table 9: OG&E Short-Term Incentive Program Payout Summary

	OG&E		OG&E Energy except CEO		CEO	
	Actual	Target	Actual	Target	Actual	Target
Corporate Financial	$ 4,430,225	$ 3,132,811	$ 3,305,732	$ 2,328,545	$ 1,358,055	$ 974,257
Departmental Financial	$ 2,506,116	$ 2,257,079	$ 734,518	$ 759,632	$ -	$ -
Non-Financial	$ 2,999,557	$ 2,932,669	$ 1,077,945	$ 1,328,244	$ -	$ -
Total	$ 9,935,898	$ 8,322,559	$ 5,118,195	$ 4,416,421	$ 1,358,055	$ 974,257
% Corp financial	44.6%	37.6%	64.6%	52.7%	100.0%	100.0%
% dept financial	25.2%	27.1%	14.4%	17.2%	0.0%	0.0%
% non-financial	30.2%	35.2%	21.1%	30.1%	0.0%	0.0%

OG&E has significantly exceeded target performance in 2007 on its financial metrics, while coming in slightly below target on non-financial customer service and business process metrics – particularly in OGE Energy.

Q. What do you recommend?

A. Following the Arkansas Commission's past practice, I recommend sharing the financial metrics 50-50 between ratepayers and shareholders, and allowing 100% of the incentives associated with non-financial metrics. I also specifically recommend that the CEO's short-term incentives (50% earnings per share, 25% utility capital and O&M budget, and 25% unregulated earnings) be set at 100% of target instead of the 141.25% of target that the CEO actually earned in the test year.

My recommendation reduces total company payroll expenses by $5,181,782 and Arkansas jurisdictional payroll by $444,187. I also reduce payroll taxes by $28,292 (Arkansas jurisdictional) using OG&E's 7.22% of payroll ratio for all but the CEO and Medicare tax only for the CEO. The table below shows the calculation.

[63] Note that there are discrepancies between AG DR 2-21 Attachment 3 and AUD-25 revised attachment 2, which purport to show the same quantities. We do not know the reason for the differences. We use AG DR 2-21 Attachment 3 (disaggregated data) to divide incentives into corporate financial, department financial, and non-financial. We have used AUD-25 (aggregated data) to develop total dollar disallowances and jurisdictional allocation.

Table 10: Attorney General's Recommended Adjustment for Short-Term Incentives

	OG&E	OGE Energy except CEO/COO	CEO/COO	Total
OG&E per AUD-25	$ 10,201,925	$ 4,940,855	$ 1,358,055	$ 16,500,835
Less Unregulated Distrigas	$ -	$ (1,146,278)	$ (315,069)	$ (1,461,347)
Less utility capitalization	$ (1,563,705)	$ -	$ -	$ (1,563,705)
Utility expense per OG&E	$ 8,638,220	$ 3,794,576	$ 1,042,986	$ 13,475,783
Reduce CEO to target (net of Distrigas)			$ (294,757)	$ (294,757)
Result after CEO reduction	$ 8,638,220	$ 3,794,576	$ 748,229	$ 13,181,026
Financial 50-50 sharing	34.91%	39.47%	50%	
AG Allowed	$ 5,623,010	$ 2,296,877	$ 374,115	$ 8,294,001
AG Adjustment	$ 3,015,210	$ 1,497,700	$ 668,872	$ 5,181,782
Arkansas %	7.76%	9.71%	9.71%	
Arkansas adjustment	233,900	145,367	64,921	**444,187**
Payroll tax	7.22%	except CEO/COO		**28,292**

2. Stock-Based Compensation

Q. What is the amount of long-term stock-based incentive compensation requested for rate recovery in the test year?

A. OG&E is requesting $2,482,868 for inclusion in rates, according to AG DR 2-24. Using the A&G allocation factor, the Arkansas jurisdictional portion is $241,086. Stock-based compensation has approximately quadrupled from 2005 to 2007, based on information that I reviewed in OG&E's last rate case (Docket 06-070-U).

Q. Is it reasonable to pay for stock-based long-term incentive compensation?

A. No. Long-term incentive compensation is tied largely to stock prices and has very little benefit to ratepayers. For OG&E, 75% of long-term incentive compensation is tied to the differential between OG&E's stock price and that of 80 other companies in the Standard and Poor's Utility Index, and 25% is tied to OG&E's own earnings per share (including unregulated earnings).[64] If OG&E's stock prices go up, shareholders can provide the compensation to the executives.

[64] OG&E, proxy statement for 2008 Annual Shareholders meeting, page 22.

Moreover, if stock prices drop, shareholders would be cushioned by the provision of cash to cover the cost of performance stock. Long-term incentive compensation also fluctuates dramatically in value over time depending on the performance of the stock market. We asked AG DR 4-4 to gain an understanding of how poor stock market performance would affect the fair value of long-term incentive compensation. It is included as Exhibit WBM-17. The fair value of performance shares granted in 2006-2008 as of the date granted was $18.0 million. The fair value of the same compensation is $11.3 million, as of December 18, 2008. The 2007 shares are actually worthless at the moment despite having a fair value of $4.3 million when granted. The amount expensed on the income statement (and thus the amount that OG&E requests in cash from its ratepayers) is unaffected by this type of fluctuation, but the corporation ultimately pays out less if market performance is poor.

In sum, long-term incentive compensation is not a cash expense, fluctuates in value based on options value calculations, is concentrated in a few executives, and does not provide significant ratepayer benefits with its focus on stock prices and earnings per share. In fact, all else being equal, larger rate increases from the utility's regulators would increase the value of stock and increase the value of executive compensation.

The Commission should adopt the same outcome for OG&E as for Entergy in Docket No. 06-101-U. There, the Commission found:

> The Commission, however, does not find substantive evidence of any material benefit to ratepayers attributable to those programs strictly tied to the stock prices of Entergy Corp. Although EAI witnesses testify to some general benefits ratepayers may enjoy, EAI offers no substantial evidence of ratepayer benefit which would justify including these stock-driven incentives in rates.[65]

The rejection of stock-based long-term incentive compensation would reduce OG&E's rate request in Arkansas by $241,086.

[65] Arkansas Public Service Commission, Docket No. 06-101-U, Order No. 10 (June 15,2007), p. 68.

B. Directors and Officers Insurance

Q. What has OG&E requested for the Directors and Officers (D&O) liability insurance?

A. OG&E has requested recovery of 100% of the cost based on a 2008 estimate of $1,042,341 (Schedule C-2.29) and an allocation of 75.45% to the utility for a total of $786,445. The Arkansas jurisdictional portion of this amount is $76,364.

Q. Have you reviewed this figure?

A. Yes. The response to AG DR 2-34 indicates that it is too high. OG&E's holding company has spent $879,794 in the 11 months ending in November 2008. This annualizes into $959,775. Using the current utility allocation factor of 74.86%, this leaves $718,487, a further adjustment of $67,957.

Q. What is your policy position with respect to ratemaking for the Directors' and Officers' (D&O) liability insurance policy?

A. It is not appropriate to allocate 100% of the cost of directors' and officers' insurance to utility ratepayers. Instead, it is reasonable to share the cost of this insurance on a 50-50 basis between ratepayers and shareholders, since directors' and officers' insurance is often called into play when shareholders of publicly traded companies sue company management.

Ratepayers should pay something for D&O insurance because the existence of the insurance does improve the ability to attract and retain qualified directors and enables them to make decisions without fear of personal liability.

At the same time, D&O insurance provides a mechanism for aggrieved shareholders to collect funds under certain circumstances. In the absence of insurance, many of the cases in which shareholders could collect funds (related to inadequate or misleading disclosures to shareholders of material company activities), would be below the line from the perspective of ratepayers.

Because shareholders are the major beneficiaries of the payouts made under these insurance policies, the policies reduce the risk of common equity investment in the event of a bad decision by management or directors. I thus recommend that shareholders share in the cost of the policy because not only do shareholders get the payoff from the insurance policy when something goes wrong, but without the insurance, ratepayers would not be liable in any event for any portion of the payment to shareholders.

Q. Have some state commissions shared D&O insurance between ratepayers and shareholders?

A. Yes. The APSC has adopted 50-50 sharing of such expenses, based on this rationale. In its Orders in four contested cases,[66] the Arkansas Public Service Commission adopted the 50-50 sharing of these expenses based on the rationale given above. Excerpts from two decisions are quoted below:

> The news (T. 1040) is replete with stories about companies experiencing lawsuits by shareholders. The Commission agrees with the AG that more often than not it is the current shareholders who sue management and who receive a large portion of the proceeds from the D&O insurance payouts. Accordingly, the Commission finds that Arkla's existing asset-based allocation for D&O insurance should be maintained and that the expense for D&O insurance should be shared on a 50-50 basis between shareholders and ratepayers.[67]

> The Commission agrees that ratepayers, as well as shareholders, benefit from good utility management, which D&O Insurance helps secure. However, as found in prior dockets, the direct monetary benefits of D&O Insurance flow to shareholders as recipients of any payment made under these policies. That monetary protection is not enjoyed by ratepayers. The Commission therefore finds that, because shareholders materially benefit from this insurance, the costs of D&O Insurance should be equally shared between shareholder and ratepayer.[68]

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[66] Dockets 02-227-U, 04-121-U, 04-176-U, and 06-101-U.

[67] (Arkansas PSC Docket No. 04-121-U, Order No. 16, page 40, September 19, 2005 http://www.apscservices.info/pdf/04/04-121-u_286_1.pdf)

[68] Arkansas PSC Docket No. 06-101-U Order No. 10, Page 70, June 15, 2007, footnote omitted, http://www.apscservices.info/pdf/06/06-101-u_303_1.pdf

Similarly, the California Public Utilities Commission has required a 50-50 sharing of this cost since 1996.[69] The 1996 decision specifically cited information brought forward by the Commission's Division of Ratepayer Advocates that the bulk of lawsuits using this insurance were brought by shareholders and that the one such shareholder suit that Southern California Edison settled resulted in a below-the-line payment of amounts less than the policy deductible. The Commission concluded:

> In D. 87-12-066, 26 CPUC 2d 392,422, we permitted these types of premiums to be recovered in rates. However, the statistics provided by DRA [Division of Ratepayer Advocates] from 1986-1993, which were not available in 1987 when we decided D. 87-12-066, illustrate that shareholders also benefit from this insurance. Therefore, we will allow half of the expenses requested by Edison for this item. By making this allocation, we are not implying that it is not necessary for Edison to maintain such insurance. To the contrary, we are funding half of the premium with ratepayer funds. However, to the extent that shareholders also benefit from this insurance, they should also share in the expense.[70]

Q. What is the effect of your proposed 50-50 sharing of D&O insurance?

A. My recommendation is to charge ratepayers for $359,244 for D&O insurance, which is 50% of the 2008 figure of $718,488. This is a downward adjustment of $427,201 - $359,244 for the 50% sharing with shareholders and $67,957 because of my lower forecast of the total amount. The Arkansas jurisdictional reduction is $41,481.

C. Normalize Wind Power Maintenance Expense

Q. Do you have any concerns regarding OG&E's wind power expenses?

A. Yes. In the first two years of operations, expenses are relatively high under a maintenance contract with General Electric but are expected to be reduced significantly when the contract expires in 2008. The response to AG DR 2-62

[69] California PUC Decision No. 96-01-011 in Application No. 93-12-025 slip. op. at 140-141, January 15, 1996, regarding Southern California Edison Company; and California PUC Decision No. 00-02-046 in Application No.. 97-12-020, slip op. at 309, February 17, 2000, regarding Pacific Gas and Electric Company.

[70] CPUC Decision No. 96-01-011, p. 141.

shows $3,447,000 in costs in 2007, but this amount falls to $3,127,000 in 2008 and $2,693,000[71] in 2009. The major reason for the reduction is a decline in maintenance contract costs from $2,788,000 in 2007 to $2,496,000 in 2008 and $1,517,000 in 2009 (offset in part by materials and supplies costs), as OG&E expects to obtain savings by choosing a new vendor to take over contract maintenance. The known and measurable change in maintenance practices should be recognized by using a two-year average of 2008-09 ($2,910,000, which is a reduction of $537,000 from the test year. The Arkansas jurisdictional amount is $60,581.

D. Dues and Donations

1. <u>Edison Electric Institute</u>

Q. Have you reviewed OG&E's dues payments to the Edison Electric Institute (EEI)?

A. Yes. OG&E spent $560,504 on EEI dues and requests $439,303 (78.4 % of the total dues) as a utility expense according to the response to AG DR 2-52. OG&E places $131,201 below the line (in FERC Account 426.4). Using the itemized invoice[72] that EEI submitted to OG&E, the breakdown is $505,004 for regular activities of EEI, $50,500 for the industry structure assessment and $5,000 for the mutual assistance program fee. To obtain the amount for which it is not seeking recovery, OG&E is not charging ratepayers for 20% of the Regular Activities of EEI and 40% of the fee for industry structure assessment, based on percentages footnoted on the invoice.

Q. What is your recommendation regarding EEI dues?

A. I recommend that a larger reduction be taken from regular activities dues. The Commission should disallow 49.93% of the Regular Activities dues for ratemaking purposes, as it did in the Entergy case (Docket 06-101-U). This

[71] Excluding insurance which is covered elsewhere and a $250,000 crane that could be reused that should be capitalized.

[72] EEI breaks down the total membership dues into Regular Activities of Edison Electric Institute, Industry Structure Assessment, and Mutual Assistance Program (Attachment to AG DR 2-52).

amount is larger than the non-taxable amount that even EEI identifies as lobbying, because 49.93% of EEI costs go for legislative and regulatory advocacy, advertising, marketing, and public relations. The table below shows how EEI spends its money.

Table 11: EEI Spending

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core Dues Activities
For the Year Ended December 31, 2005

NARUC Operating Expense Category	% of Dues
Legislative Advocacy	20.38%
Legislative Policy Research	6.02%
Regulatory Advocacy	16.49%
Regulatory Policy Research	13.99%
Advertising	1.67%
Marketing	3.68%
Utility Operations and Engineering	11.31%
Finance, Legal, Planning and Customer Service	18.75%
Public Relations	7.71%
Total Expenses	100.00%

In addition, 40% is removed from the Industry Structure Assessment portion of the dues (like OG&E's original request). The Attorney General, therefore, proposes to disallow EEI-related expenses, per the following table:

Table 12: EEI Disallowance

	Gross	Lobbying and similar activities	AG disallowance
Regular Activities	505,004	49.93%	252,148
Industry Structure	50,500	40%	20,200
Mutual Assistance	5,000	0%	-
Total	560,504		272,348
OG&E reduction			121,201
Additional AG reduction			151,148

So, while OG&E places $121,201 of EEI dues below the line (in FERC Account 426.4), we recommend the Commission place $273,348 in FERC Account 426.4, which is an additional $151,148. The Arkansas jurisdictional portion of this adjustment is $14,312.

2. Other Organizations

Q. What other dues have you reviewed?

A. I started by reviewing the dues, donations, and expenses in Schedule C-6. It is noteworthy that Schedule C-6 failed to include luncheon and country club dues for which OG&E requests ratepayer funding (See AG DR 2-31).

Q. Aside from the Edison Electric Institute what has OG&E requested for dues and donations in Schedule G-4.3a?

A. It requested $287,433 above the line.

Q. Do you have any recommended disallowances?

A. Yes. I first remove $160,555 in dues to chambers of commerce (and the chamber-affiliated Associated Industries of Arkansas). Chambers of commerce are political organizations that ratepayers should not subsidize. The Arkansas PSC has disallowed chamber of commerce dues in a number of past cases including Docket 06-101-U. I have also identified $13,010 in charitable donations, club dues, and similar costs for 29 organizations that should be disallowed under long-standing Arkansas PSC policy. There is an additional $818 to 15 organizations under $100 each, of which I disallowed 50% or $409 rather than examining each item individually.

The total of all of these disallowances is $173,974. The Arkansas jurisdictional amount is $16,474.

3. Club Dues

Q. Does OG&E request ratepayer funding for luncheon and country club dues?

A. Yes, it does. According to AG DR 2-31, the holding company spent $129,511 in 2007, of which $34,481 was directly assigned to Enogex, leaving $95,030. The Distrigas allocation assigns 76.76% of these costs to Oklahoma Gas and Electric Company, or $72,945. The Arkansas jurisdictional adjustment is $6,907.

Q. Should the Commission allow this expense in rates?

A. No. Club dues are not a cost necessary to provide utility service and are routinely disallowed by not only the Arkansas PSC but state commissions across the country.

E. Advertising Expenses

Q. Have you reviewed OG&E's proposed advertising expenses?

A. Yes. Through Schedule C-7 and pro forma adjustment C-2.2-13, OG&E requests ratepayer funding of $1,896,839 in advertising costs in Accounts 909, 913, and 930.1, of which $159,334 is allocated to Arkansas. A significant portion of these costs should not be allowed for ratemaking purposes in Arkansas. I recommend disallowing a further $295,612 (beyond the $1,422,639 removed from costs in adjustment 2-13) and using direct assignment for many costs where costs are incurred separately for Arkansas and Oklahoma markets. In sum, of the $1,601,227 of allowable expenses, direct assignment plus allocation yields only

$88,928 in Arkansas jurisdictional expenses, because OG&E heavily concentrates its advertising in Oklahoma.

The Table below revises Schedule C-7 to show the Attorney General's proposed adjustment for advertising. OG&E's responses to AG DRs 2-41 and 2-42 provide further information supporting the disallowances and direct assignments.

<u>Table 13: Attorney General's Advertising Adjustments to Schedule C-7</u>

	Total per OG&E	disallow	allocate to states	direct assign to OK	direct assign to AR	
Account 909						
Wind Rider	255,044			255,044		wind rider not offered in AR
Safety OK	213,919			213,919		direct assign
Bill Inserts OK	162,535			162,535		direct assign
Regulated business	154,507		154,507			
Community affairs OK	110,477			110,477		direct assign
Environmental	99,940	99,940				image & political advertising
Wind power	75,000	75,000				state fair and plant dedication
energy efficiency OK	65,201			65,201		direct assign
econ development OK	53,433			53,433		direct assign
storm outage	36,771		36,771			
OK city regatta	31,250	31,250				image advertising, also not AR
Bill Inserts AR	6,738				6,738	direct assign
Miscellaneous	1,484		1,484			
Safety AR	1,420				1,420	direct assign
Community affairs AR	788				788	direct assign
Total Account	1,268,507	206,190	192,762	860,609	8,946	
Arkansas allocation			8.40%	0.00%	100.00%	
Arkansas cost per AG	25,138		16,192	-	8,946	
Arkansas cost per OG&E	106,555					
Arkansas jurisdictional adjustment	81,417					
Account 913 (after C2.2-13 adjustment)						
Wind power	5,000	5,000				image advertising - Tinker AFB sponsorship
Energy efficiency tips	220,459		220,459			
Supplemental Safety	295,703		295,703			
Promotional items	58,918	58,918				fans, trading cards, backpacks
Advertising agency	22,748		22,748			
Total account	602,828	63,918	538,910			
Arkansas cost per AG	45,268		45,268			
Arkansas cost per OG&E	50,638					
Arkansas jurisdictional adjustment	5,369					
Account 930.1						
Company Store	25,504	25,504				OG&E gear
Arkansas cost per AG	-		-			
Arkansas cost per OG&E	2,142					
Arkansas jurisdictional adjustment	2,142					
Total	1,896,839	295,612	731,672	860,609	8,946	
Arkansas cost per AG	**70,406**	-	61,460	-	8,946	
Arkansas cost per OG&E	**159,334**					
Arkansas jurisdictional adjustment	**88,928**					

Q. Will you explain the basis for the specific reductions that you recommend?

A. Starting with Account 909, I recommend removing the wind power advertising ($249,522). According to AG DR 4-8, this advertising expense was incurred to encourage Oklahoma customers to sign up for a "green power" tariff to purchase wind power. While OG&E claims it is an "energy conservation" cost under Arkansas rules, it was certainly not used and useful to Arkansas ratepayers, because they could never sign up for the tariff in question. Moreover, the advertisement had a significant image component (by encouraging customers to see OG&E as an environmentally friendly company because of the wind power, even while OG&E was lobbying to oppose a renewable portfolio standard). The wind advertising cost is therefore entirely Oklahoma jurisdictional and never should have been allocated to Arkansas in the first place. In sum, Arkansas customers should not pay for it. I also directly assign advertising on safety, community affairs, and bill inserts to the state for which they were produced, along with economic development advertising (Oklahoma only) and energy efficiency advertising for Oklahoma's specific programs.

In Account 909, I also recommend disallowing other advertising for wind power and environmental purposes as image and politically related. The wind power costs were for a ride at the Oklahoma State Fair, as well as sending out mailers announcing the opening of the Centennial Wind Farm and taking dignitaries to lunch after the opening ceremony. The environmental advertising was designed to encourage ratepayers to see OG&E as environmentally friendly and to support OG&E's views of environmental issues in the political arena (e.g., opposing renewable portfolio standards and supporting coal-fired power generation).

In AG DR 2-42, OG&E provided details of the Account 913 spending after costs were removed for Adjustment C2.2-13. Of the remaining $603,000, I recommend disallowing $5,000 for wind power-related image advertising (a sponsorship of an event at Tinker Air Force Base) and $58,918 for promotional gear such as fans, trading cards, and children's' backpacks.

In account 930.1, I recommend removing the $25,504 cost of company promotional items, which the Commission has typically removed for ratemaking purposes in other cases as not necessary to provide utility service.

Q. Will you summarize your recommendation?

A. Arkansas jurisdictional costs are reduced from OG&E's request of $159,334 to $70,406, a reduction of $88,928. These changes result from a total cost disallowance of $295,612 and use of direct assignment for jurisdictional allocation of many advertising expenses in Account 909.

F. Fuel Inventory Rate Base

Q. Do you propose any adjustments for gas inventory?

A. Yes. I propose a reduction of $11,612,000 in total company rate base ($1,230,000 Arkansas jurisdictional rate base, lowering the revenue requirement by approximately $102,000 at the AG's rate of return and $131,000 at OG&E's rate of return) to reflect OG&E's actual method of accounting and the lower actual cost of gas than OG&E forecast in 2008. OG&E's end of year gas inventory in 2007 was $8,552,905. Its 13-month average gas inventory was $7,846,497. OG&E computed its 2008 gas inventory by marking the end of year quantity in 2007 to a 2008 forecast market price of $10.36/MMBtu, obtaining a figure of $21,056,524. This inventory amount failed to consider the fact that over 2 million MMBtu were contained in inventory at the end of 2007 at a price far lower than the 2008 forecast market price.

Moreover, OG&E uses Last-in-First-Out (LIFO) accounting for fuel inventory.[73] This fact alone makes it absolutely illegitimate for OG&E to mark the entire inventory quantity to market as it proposes to do in this rate case. To add insult to injury, OG&E's market price forecast also turned out to be higher than prices that

[73] Oklahoma Gas and Electric Company 2007 SEC Form 10-K, p. 56.

actually occurred (which were only $8.97 at Henry Hub and considerably lower at locations where OG&E would purchase gas in Oklahoma).

Q. What is your recommendation?

A. Updating the figures to actual 2008 figures could be appropriate. I recommend that actual gas inventory quantities and prices be used. I have created a placeholder figure of $9,894,692 – a reduction of $11,611,882, which uses LIFO accounting forecast prices as gas is added to inventory and uses the average of Henry Hub spot prices on the weekdays closest to the first and fifteenth of each month to value inventory additions. A 13-month average quantity of gas is also used, which is less than OG&E's end-of-year quantity of gas.

Q. Do you propose an adjustment to OG&E's request for additional coal inventory?

A. Yes. I propose a reduction of $20,503,576 in total company rate base ($2,172,000 Arkansas jurisdictional rate base, lowering the revenue requirement by approximately $180,000 at the AG's rate of return and $233,000 at OG&E's rate of return) to recognize LIFO accounting. OG&E has proposed a 75-day inventory level of 2,475,000 tons, which it valued on a "mark to market" basis at a 2008 forecast price of $29.1794 per ton or $72,219,015.

I take no position on the reasonableness of whether OG&E actually needs 75 days of inventory at this time, although the requirement for 75 days appears high to me based on past information. I do note that OG&E was in the process of increasing inventory late in 2007 and was carrying about 58 days of inventory at the end of 2007, a higher amount than earlier in the year.

However, even if one were to assume that OG&E needs 75 days of inventory, OG&E incorrectly computed the value of that inventory by again ignoring its own LIFO accounting practice. If a 75-day inventory is adopted, the inventory at the beginning of the year will likely remain in inventory for accounting purposes throughout the year because it would be unlikely to be burned except under adverse conditions. OG&E should have added the ***additional*** tonnage beyond end-of-year 2007 (557.611 tons) at its forecast price of $29.1794 per ton to the existing end-of-year 2007 inventory of 1,917,389 tons at a cost of $35,444,685.

Adding the figures together, the appropriate inventory cost, after applying LIFO accounting to OG&E's requested 75 days of inventory, becomes $51,715,439, a reduction of $20,503,576 from OG&E's request.

G. Red Rock Coal Plant

Q. What is the Red Rock project?

A. It is a coal-fired power project that was planned by a consortium of several utilities including OG&E. The project was rejected by the Oklahoma Corporation Commission, but only after approximately $17 million in costs were incurred. Ultimately in Oklahoma, the Commission approved recovery of 50% of the Oklahoma jurisdictional costs with no carrying charges. OG&E has requested similar treatment here and has asked for $860,000 amortized over two years at $430,000 per year.

Q. Have other state commissions faced questions regarding abandoned plant?

A. Yes. I am particularly familiar with several cases when the California PUC faced these questions in the 1980s. Pacific Gas and Electric Company had continued to include a number of discontinued projects in Construction Work in Progress (CWIP) and Plant Held for Future Use (PHFU), while at the same time requesting to place CWIP in the rate base and collecting on PHFU. In 1983, PG&E requested recovery of the costs. In Decision 83-12-068, the Commission laid out the general framework:

> We begin by analyzing these projects under used and useful principles, long followed by our Commission. Under these principles, ratepayers are required to bear only the reasonable costs of those projects which provide direct or ongoing benefits, or are used and useful in providing adequate and reasonable service, to the ratepayers. Those projects which never reach fruition by definition fail to be used and useful to the ratepayers. As a result

> the costs incurred in determining the feasibility of a given project which is later abandoned are borne by the shareholders.
>
> By our requiring shareholders to absorb feasibility study costs, management has an economic incentive to select only those projects that are reasonably likely to succeed. Importantly, it is management alone that decides which projects to pursue and which to abandon.[74]

Despite these principles, the California PUC eventually allowed recovery of costs of a number of projects undertaken in the 1970s, with a four-year amortization, no return, and no AFUDC, in large part because of the specific uncertainties that occurred in that decade after the oil embargo.[75] On rehearing, the Commission partially reversed itself and completely disallowed recovery for one nuclear project that was cancelled earlier in the 1970s before the oil embargo because it was located on an earthquake fault.[76]

Ultimately the California PUC set down some specific principles that a utility "should not recover the cost of a plant not used or useful, unless the utility can show:"

> (1) that the project ran its course during a period of unusual and protracted uncertainty. (2) that the project was reasonable through the project's duration in light of both the relative uncertainties that then existed and of the alternatives for meeting the service needs of the customers, (3) when the projects were cancelled, and (4) that they were cancelled promptly when conditions warranted.[77]

The California PUC followed these principles in this decision to deny recovery for Southern California Edison's costs of the California-Oregon Transmission

[74] CPUC Dec. No. 83-12-068 14 CPUC 2d 15 at 50.

[75] *Ibid* at 50-52.

[76] CPUC Decision No. 84-05-100, slip. op at 6.

[77] CPUC Decision No. 96-01-011, slip. op. at 54, quoting from Decision No. 91-12-076, 42 CPUC2d 645 at 688, which in turn quoted from Decision No. 89-12-057, 34 CPUC2d 199 at 269.

Project after the Commission rejected a certificate of Public Convenience and Necessity for that project.[78]

Q. Do you have a recommendation on whether the project should be disallowed?

A. Not at this time. I present this information to assist the Commission by providing a framework for considering the project. I may have some further comments of a policy nature after reviewing the factual context laid out in further testimony from Staff and the Company.

Q. If recovery is allowed for this project should it be amortized over two years as proposed by OG&E?

A. No. I would recommend a longer amortization (i.e., four years) as a further means of sharing any risk. A four year amortization would reduce OG&E's rate request by $215,000.

H. Jurisdictional Allocation of Centennial Windfarm

Q. What is your concern regarding the allocation of the Windfarm between Arkansas and Oklahoma?

A. OG&E allocated wind farm production plant costs on an energy basis to customer classes in Arkansas, but allocates 11.28% of the total cost to Arkansas (and 88.72% to Oklahoma) instead of 10.59% to Arkansas (and 89.41% to Oklahoma) like all other energy-related costs. This difference is not explained. In the absence of an explanation, wind farm production plant costs should be treated like all other energy costs.

Q. What is the approximate impact of using the same 10.59% allocation for the wind project as for other energy-related expenses?

[78] Dec. No. 96-01-11, pp. 54-57.

A. Using the same energy allocation factor for all energy rather than allocating more of the Windfarm to Arkansas would reduce Arkansas jurisdictional rate base by $1,352,550 (reducing the revenue requirement by $112,000 at the AG's rate of return and $145,000 at OG&E's rate of return). It would also reduce O&M expenses by $24,000 (assuming OG&E's O&M expenses) and depreciation expense by $55,000. The total impact is about $180,000.

IV. Cost of Service and Rate Design

A. Cost of Service Study

Q. Will you discuss the OG&E cost of service study in general terms?

A. OG&E provided a cost of service study for Arkansas that uses the parameters on which the parties settled in the last rate case (Docket 06-070-U). I believe that study to be reasonable in its broad outline. OG&E has also reasonably addressed my concern from the last case regarding the jurisdictional allocation of Accounts 583 and 593.

As a result, I recommend only two minor changes, related to the class allocation of costs of expenses for major account representatives and economic development programs.

Q. What is a major account representative?

A. A major account representative is a utility staff member who provides service to large customers. In the case of OG&E, the response to AG DR 3-01 shows that OG&E spends $3,414,000 on major account representatives, of which $3,144,000 is above the line and $2,061,986 is in customer service and information and sales and marketing accounts 908-916. The remainder is largely in Account 926 (pensions and benefits for staff) and Account 930.2. Arkansas is allocated 8.4% of the costs in Accounts 908-916 based on the number of customers, and the costs are spread over all customer classes by equal numbers of customers.

Q. Who do major account representatives serve in OG&E's service territory?

A. According to AG DR 3-2, they serve 95% power and light customers and 5% general service customers.

Q. What is the total amount of costs allocated to Arkansas power and light customers (both regular and TOU) in Accounts 901, 905, and 907-916 (meter reading, customer accounting, customer service, and sales and marketing but excluding meter reading and bad debt)?

A. The amount is $36,718.

Q. What is 95% of the Arkansas jurisdictional cost of major account representatives in Accounts 908-916?

A. The amount is $164,546.

Q. Do you believe it to be reasonable for small customers to pay for services provided to large customers?

A. No.

Q. What is your recommendation?

A. I have added 95% of the Arkansas jurisdictional major account representatives costs to the power and light and power and light TOU classes. From this figure, I have netted out the existing allocation to the light and power class in Accounts 908-916 (except allocated economic development expenses dealt with below) and half of the power and light allocation in Account 905 ($10,480) to recognize that some functions like call centers are not used by large customers who use major account representatives. I also assigned the remaining 5% of the Arkansas jurisdictional costs of major account representatives to the general service class consistent with AG DR 3-2.

I took account of the direct assignment by reducing the costs allocated to the residential, general service, pumping, and lighting classes in proportion to the original allocation of their costs.

After including the impact on A&G allocated by O&M expenses, the residential decrease from this change would be about $184,000.

Q. Has the Arkansas PSC previously agreed with you on this issue for another utility?

A. Yes, in large part. The Commission rejected a customer-based allocation factor for Accounts 908-915 in the last Entergy Arkansas case (Docket 06-101-U), based on my testimony. It stated:

> [T]he Commission also finds that, in view of the analysis provided by Mr. Marcus, the actual expenditures reflect that the "customer-count" allocation would not be appropriate. Many of these costs appear to directly benefit commercial and industrial customers. [79]

Q. Will you discuss economic development program spending?

A. OG&E spent $626,858 in Accounts 912 and 913 on economic development ($52,656 Arkansas jurisdiction). The costs were allocated by number of customers, so that the residential class was allocated 84% of Arkansas spending.

Q. Should these costs be allocated predominantly to residential customers or should a broader allocation factor be used?

A. The broader allocation is more appropriate. Exhibit WBM-18 (the response to AG DR 3-3) shows OG&E's rationale for economic development spending.

[79] See APSC Order No. 10 in Docket No. 06-101-U, pages 95-96. The methodology that I used in the EAI case and that the Commission adopted for EAI (allocating costs by a utility plant factor) is different than the direct assignment method that I propose here for major account representatives, because (1) EAI used it for sales and marketing costs and (2) EAI included other costs like dues, sponsorships, etc. in Accounts 908-915 that should be broadly allocated, even though they should not be assigned directly to large customers. OG&E does not appear to have included such costs in these accounts, so direct assignment of the cost of major account representatives is the more appropriate response to the issue here.

While these activities may be laudable, they have nothing to do with the number of customers.

It is unreasonable to think, for example, that the benefits to a General Service or Light and Power retail store from having a new factory locate in the area due to the utility's efforts would be the same as the benefits of the average residential customer. And if economic development efforts are successful, all customers would benefit by deferring the time of future rate cases and/or reducing the amount of future increases. The benefit would be roughly in proportion to base revenue.

Entergy uses a broad allocation factor for sales and marketing expenses including economic development (utility property), rather than a customer-based allocation. I propose a similar broad allocation factor here – base revenue.

Q. What is the impact of your recommendations?

A. The changes to major account representatives and economic development allocation have the following impacts on O&M expenses in Accounts 908-916. With changes to A&G expense and general plant allocation (through the "Supervised O&M" allocation factor) consequential to these changes, the total impact on the class allocation would be about 50% greater.

Table 14: Impact on O&M Cost Allocation of AG's Allocation of Expenses for Major Account Representatives and Economic Development

	Major Account Reps	Economic Development	Total
Residential	(126,534)	(23,416)	(149,950)
General Service	(12,692)	(1,553)	(14,245)
Light and Power	130,400	12,347	142,747
Light and Power TOU	9,142	10,730	19,872
Lighting	(61)	1,903	1,842
Pumping	(181)	(17)	(198)
Athletic Lighting	(74)	6	(68)

Q. Have you prepared a cost of service study with the Attorney General's recommendations?

A. Not at this time. I will prepare one for rebuttal testimony when I receive a better version of the COSS. When I turned to my analysis of cost-of-service issues, I found that the company gave me a version of the COSS that did not have active spreadsheet formulas and was also password protected so that I could not revise it myself.

Q. Would any rate classes require mitigation of rate shock given the results of the cost of service study as proposed by OG&E and as you would modify them?

A. Yes. The Athletic Field lighting class is slated for a large increase that should be mitigated. It is my understanding that Staff is investigating this issue.

B. Residential Rate Design

1. OG&E's Proposal

Q. Will you describe OG&E's current rate design?

A. OG&E currently has a rate structure with a customer charge, an inverted block rate for large users (over 1500 kWh) in the summer months, and a very pronounced declining block rate in the winter months for users over 1000 kWh. The basic residential rate structure is now a customer charge of $6.50, a summer first block (up to 1500 kWh per month) of 4.066 cents/kWh, a second block (over 1500 kWh per month) of 4.335 cents per kWh, a winter first block of 2.948 cents/kWh up to 600 kWh per month, and a winter tail block of 1.600 cents/kWh. There are different rates for a few time-of-use customers.

Q. What has OG&E proposed in this case?

A. In the context of its proposed increase, it proposes to increase the customer charge by 80% from $6.50 to $11.70 and to increase the summer rates by 28.8% (with a 13% increase on the first block rate and an 89% increase on the second inverted tier rate). Winter rates would be virtually constant (a minor first block increase).

Q. Why has OG&E proposed to increase the customer charge to $11.70?

A. It proposes to raise the charge to what it considers the full cost of service level. (see AG DR 3-16) In other words, cost incurrence is the most important factor.

Q. Is the residential customer-related cost really $11.70?

A. No. After taking into account the Attorney General's lower rate of return (and associated lower income taxes), the disallowance of advertising costs in Accounts 909 and 913, and the reallocation of costs of major account representatives and economic development, the cost is considerably lower.

Q. Should the customer charge be raised in this case?

A. No, for reasons discussed below. A higher customer charge is inimical to the efficient use of energy, as well as providing disproportionate increases to lower income people, who on average are likely to use less energy than higher income people.

Q. What is your opinion of the proposal to provide almost no increase to winter rates in the context of a 28.8% annual base rate increase for residential customers?

A. While costs should be somewhat lower in winter than in summer, I do not believe it is reasonable to discount the average winter base rate by 56% from the average summer kWh or to provide all usage above 600 kWh per month at a 66% base rate discount to average summer usage .

It appears to me that with this rate design OG&E is positioning itself to fight gas companies over whether gas or electricity will be used as a heating source, with a combination of extremely low winter base rates and the customer charge increase.

In recent years, approximately 20% of new Arkansas customers have been choosing electric heat in the OG&E service area. (AG DR 3-20, Exhibit WBM-19)

2. Policy Considerations

Q. Will you describe the Attorney General's long-term policy for residential rate design?

A. In the long term, residential rate design should have as a significant goal the encouragement of conservation of energy (including encouraging the use of natural gas where it is more efficient than electricity). To do this, we have an ultimate goal to minimize reliance on fixed charges (customer charges) and declining block rates. We recognize that gradualism is important so that existing customers who have installed equipment in reliance on certain types of rate structures are not harmed. A flat or inverted summer rate, a moderately lower flat winter rate, and limited reliance on customer charges would satisfy this long-term goal. Inverted rates in the summer months also tend to reflect costs for residential customers, since base levels of use relate to non-weather-sensitive use such as refrigeration, lighting, etc. The weather-sensitive use creates the system peak and therefore should be charged more.

Q. Will you comment on the impact of customer charges and declining block rates on energy efficiency?

A. All else being equal an increased residential customer charge will decrease the cost-effectiveness of measures that save electricity. Moreover, a high customer charge decreases the effectiveness of energy efficiency programs operated by the utility by making it less cost-effective for customers to conserve. The end result of having rate design compete with efficiency programs is either higher rebates raising program costs or lower penetration of the programs or both. Given the Commission's move toward the development of significant energy efficiency programs it should not be driving with one foot on the gas (efficiency programs) and the other foot on the brake (promotional rate design). Rate design and efficiency policy should be harmonized, not at cross-purposes with each other.

Q. Have you analyzed the relative use of energy by gas and electric end uses?

A. The table below (with supporting data in the workpapers) shows the energy efficiency of gas versus electric use for space heating, water heating, and clothes drying.[80] For electric heat, the issue is whether the customer uses a heat pump or electric resistance heating. The resistance heating is far less efficient than burning gas directly in the residence. While a gas combined cycle fueling a heat pump is slightly more energy efficient than a gas furnace. However, a heat pump generally does not stand alone but comes with other electric appliances. When these appliances are brought along into the all-electric home, they dramatically reduce the efficiency of total energy use. Moreover, when coal-fired electric generation is at the margin, the amount of both energy use and greenhouse gas emissions burgeons due to electric heat, even with a heat pump.

[80] Propane heat would have similar efficiency to gas at the end use, but may have somewhat more energy losses in delivery to the customer.

Table 15: Total Energy Efficiency of Natural Gas vs. Electric Service for Residential End Uses

	gas	electric combined cycle	coal steam
gas vs. electric resistance heat			
end-use efficiency	90%	100%	100%
conversion and delivery efficiency *	98%	45%	31%
implicit heat rate Btu/kWh	3,870	7,630	10,900
efficiency	88%	45%	31%
energy required for end-use electricity relative to gas		197%	282%
CO_2 per MMBtu of heat input (pounds)	115	115	210
CO_2 for same useful output as 1 MMBtu of gas heat input	115	227	592
additional CO_2 for electric option		97%	414%
gas vs.air-source heat pump (Heating Seasonal Performance Factor = 8.2)			
end-use efficiency	90%	240%	240%
conversion and delivery efficiency	98%	45%	31%
implicit heat rate Btu/kWh	3,870	3,176	4,537
efficiency	88%	107%	75%
energy required for end-use electricity relative to gas		82%	117%
CO_2 per MMBtu of heat input (pounds)	115	115	210
CO_2 for same useful output as 1 MMBtu of gas heat input	115	94	246
additional CO_2 for electric option		-18%	114%
water heater			
end-use efficiency	63%	93%	93%
conversion and delivery efficiency	98%	45%	31%
implicit heat rate Btu/kWh	5,528	8,204	11,720
efficiency	62%	42%	29%
energy required for end-use electricity relative to gas		148%	212%
CO_2 per MMBtu of heat input (pounds)	115	115	210
CO_2 for same useful output as 1 MMBtu of gas heat input	115	171	445
additional CO_2 for electric option		48%	287%
clothes dryer			
end-use efficiency (relative to electricity to dry same amount of clothes)	89%	100%	100%
conversion and delivery efficiency	98%	45%	31%
implicit heat rate Btu/kWh (adjusted for slightly lower gas end-use drying efficiency)	3,926	7,630	10,900
efficiency	87%	45%	31%
energy required for end-use electricity relative to gas		194%	278%
CO_2 per MMBtu of heat input (pounds)	115	115	210
CO_2 for same useful output as 1 MMBtu of gas heat input	115	223	583
additional CO_2 for electric option		94%	407%

* Gas delivery losses between the site of a powerplant and a residence. Electric efficiency based on combined cycle heat rate of 7000 Btu/kWh, coal heat rate of 10000 Btu/kWh, 9% line loss.

Q. What policy concerns does the Commission face in light of this information?

A. The Commission needs to balance two concerns: (1) the need to price electricity to support energy efficiency and reduce the increased use of energy that arises from the unwise promotion of electric heat; and (2) the need to avoid potential harm to existing customers who have relied on existing and past promotional rates.

Q. How can the Commission balance these competing concerns?

A. It can gradually make the rate design less promotional (by decreasing the absolute difference between first block and tailblock rates and adopting an inverted summer rate).

3. Recommended Rate Design Principles (Block Rates and Customer Charges)

Q. What is your rate design recommendation in this case?

A. I recommend that rates be designed on the following principles if there is a significant increase:

- No increase to the customer charge for the reasons discussed above.
- In a case with a significant rate increase, rates should be increased in both seasons unlike OG&E's proposal, but the average increase in the summer (measured in cents per kWh, not percentage of the bill) should be greater than in the winter. We recommend an increase in the winter rate (averaged over the two blocks) that is in the range of 70-80% of the increase in cents per kWh in the summer months.
- We specifically agree with the principle of an inverted block summer rate as proposed by OG&E and also agree with a disproportionate increase on the second summer block. However, unlike OG&E, we believe that gradualism is needed rather than raising rates for very large users by as much as 27% including the ECR (the increase proposed by OG&E for a user of 3000 kWh per month). We would recommend that in this rate case, the base rate tiering be increased from the current relatively nominal

level of 6.6% of base rates to approximately 25%. Further increases in the second tier inverted block relative to the base rate are reasonable in the longer term but should not be adopted all at once.

- The first tier winter rate should not be reduced.
- The winter declining block rate differential is 1.4 cents per kWh. A goal for this case should be to cut that amount approximately in half to 0.7 to 0.8 cents/kWh to the extent possible.

It may not be feasible to meet all of these goals at once, particularly if there is no rate increase or only a very limited increase. With a very limited increase (e.g., base rate increase of 3% or less), first block rates should be frozen along with the customer charge and at least a limited amount of summer inversion and closure of the winter declining block should be pursued, though the full 25% tier inversion and reduction of the declining block by 50% may not be feasible. If a decrease is approved, all decreases should apply to the first blocks in both seasons in equal cents per kWh, and the second tier should be frozen.

I have prepared two alternative rate designs showing the application of the rate design principles above. The first assumes that the Company's revenue requirement is adopted. It is presented only as a comparison to the Company's rate design, as I do not expect a 28.8% residential base rate increase to be adopted. The second rate design shows the application of these principles assuming a 10% base rate increase, to reflect a range of outcomes taking into account cases presented by the Staff and the Attorney General.

The table on the next page compares current rates, OG&E's proposal, and the alternative rate designs. The following table compares bill impacts (including the ECR and EECR riders).

Table 16: Comparison of OG&E's Rate Design and Alternatives Based on Attorney General's Principles

		Present Rates		OG&E Proposal				AG Alternative OG&E Rev Req				AG Alternative 10% increase			
	billing determinants	rates	revenue	rates	revenue	c/kWh increase	% increase	rates	revenue	c/kWh increase	% increase	rates	revenue	c/kWh increase	% increase
customer charge	643,476	$ 6.50	4,182,594	$ 11.70	7,528,669	$ 5.20	80.0%	$ 6.50	4,182,594	0	0.0%	6.5	4,182,594	0	0.0%
Summer															
up to 1500 kWh	275,478,000	0.04066	11,200,935	0.04600	12,671,988	0.00534	13.1%	0.05070	13,966,735	0.01004	24.7%	0.04340	11,955,745	0.00274	6.7%
>1500 kWh	67,087,000	0.04335	2,908,221	0.08200	5,501,134	0.03865	89.2%	0.06337	4,251,303	0.02002	46.2%	0.05425	3,639,470	0.01090	25.1%
average		0.04119		0.05305		0.01186	28.8%	0.05318		0.01199	29.1%	0.04552		0.00434	10.5%
Winter															
up to 600 kWh	193,939,000	0.02948	5,717,322	0.03000	5,818,170	0.00052	1.8%	0.03550	6,884,835	0.00602	20.4%	0.03000	5,818,170	0.00052	1.8%
>600 kWh	178,736,000	0.01600	2,859,776	0.01600	2,859,776	-	0.0%	0.02850	5,093,976	0.01250	78.1%	0.02216	3,960,790	0.00616	38.5%
average		0.02301		0.02329		0.00027	1.2%	0.03214		0.00913	39.7%	0.02624		0.00322	14.0%
Total revenue			26,868,849		34,379,737				34,379,442				29,556,769		
				summer increase % of winter			2.3%				76.1%				74.3%
				closure of winter declining block			-3.9%				48.1%				41.8%
				summer Tier 2 vs. Tier 1			78.3%				25.0%				25.0%

Table 17: Bill Impacts of OG&E Proposal and Attorney General Alternatives

	Current Rates	OG&E Proposed			AG Alternative OG&E Rev Req			AG Alternative 10% Increase		
kWh	bill	bill	% increase	$ increase	bill	% increase	$ increase	bill	% increase	$ increase
Summer										
100	$ 14.98	$ 20.72	38.3%	$ 5.73	$ 15.99	6.7%	$ 1.00	$ 15.26	1.8%	$ 0.27
200	$ 23.47	$ 29.73	26.7%	$ 6.27	$ 25.47	8.6%	$ 2.01	$ 24.01	2.3%	$ 0.55
300	$ 31.95	$ 38.75	21.3%	$ 6.80	$ 34.96	9.4%	$ 3.01	$ 32.77	2.6%	$ 0.82
400	$ 40.43	$ 47.77	18.1%	$ 7.34	$ 44.45	9.9%	$ 4.02	$ 41.53	2.7%	$ 1.10
500	$ 48.92	$ 56.79	16.1%	$ 7.87	$ 53.94	10.3%	$ 5.02	$ 50.29	2.8%	$ 1.37
600	$ 57.40	$ 65.80	14.6%	$ 8.40	$ 63.42	10.5%	$ 6.02	$ 59.04	2.9%	$ 1.64
700	$ 65.88	$ 74.82	13.6%	$ 8.94	$ 72.91	10.7%	$ 7.03	$ 67.80	2.9%	$ 1.92
800	$ 74.37	$ 83.84	12.7%	$ 9.47	$ 82.40	10.8%	$ 8.03	$ 76.56	2.9%	$ 2.19
900	$ 82.85	$ 92.86	12.1%	$ 10.01	$ 91.89	10.9%	$ 9.04	$ 85.32	3.0%	$ 2.47
1000	$ 91.33	$ 101.87	11.5%	$ 10.54	$ 101.37	11.0%	$ 10.04	$ 94.07	3.0%	$ 2.74
1100	$ 99.82	$ 110.89	11.1%	$ 11.07	$ 110.86	11.1%	$ 11.04	$ 102.83	3.0%	$ 3.01
1200	$ 108.30	$ 119.91	10.7%	$ 11.61	$ 120.35	11.1%	$ 12.05	$ 111.59	3.0%	$ 3.29
1300	$ 116.78	$ 128.93	10.4%	$ 12.14	$ 129.84	11.2%	$ 13.05	$ 120.35	3.1%	$ 3.56
1400	$ 125.27	$ 137.94	10.1%	$ 12.68	$ 139.32	11.2%	$ 14.06	$ 129.10	3.1%	$ 3.84
1500	$ 133.75	$ 146.96	9.9%	$ 13.21	$ 148.81	11.3%	$ 15.06	$ 137.86	3.1%	$ 4.11
1600	$ 142.50	$ 159.58	12.0%	$ 17.08	$ 159.57	12.0%	$ 17.06	$ 147.70	3.6%	$ 5.20
1700	$ 151.26	$ 172.20	13.8%	$ 20.94	$ 170.32	12.6%	$ 19.06	$ 157.55	4.2%	$ 6.29
1800	$ 160.01	$ 184.81	15.5%	$ 24.81	$ 181.07	13.2%	$ 21.07	$ 167.39	4.6%	$ 7.38
1900	$ 168.76	$ 197.43	17.0%	$ 28.67	$ 191.83	13.7%	$ 23.07	$ 177.23	5.0%	$ 8.47
2000	$ 177.51	$ 210.05	18.3%	$ 32.54	$ 202.58	14.1%	$ 25.07	$ 187.07	5.4%	$ 9.56
2500	$ 221.28	$ 273.14	23.4%	$ 51.86	$ 256.36	15.9%	$ 35.08	$ 236.29	6.8%	$ 15.01
3000	$ 265.04	$ 336.22	26.9%	$ 71.18	$ 310.13	17.0%	$ 45.09	$ 285.50	7.7%	$ 20.46
3500	$ 308.80	$ 399.31	29.3%	$ 90.51	$ 363.90	17.8%	$ 55.10	$ 334.71	8.4%	$ 25.91
4000	$ 352.56	$ 462.40	31.2%	$ 109.84	$ 417.67	18.5%	$ 65.11	$ 383.92	8.9%	$ 31.36
4500	$ 396.32	$ 525.48	32.6%	$ 129.16	$ 471.44	19.0%	$ 75.12	$ 433.13	9.3%	$ 36.81
5000	$ 440.09	$ 588.57	33.7%	$ 148.49	$ 525.22	19.3%	$ 85.13	$ 482.35	9.6%	$ 42.26
Winter										
100	$ 13.87	19	37.9%	$ 5.25	$ 14.47	4.3%	$ 0.60	$ 13.92	0.4%	$ 0.05
200	$ 21.24	27	25.0%	$ 5.30	$ 22.44	5.7%	$ 1.20	$ 21.34	0.5%	$ 0.10
300	$ 28.61	34	18.7%	$ 5.36	$ 30.41	6.3%	$ 1.81	$ 28.76	0.5%	$ 0.16
400	$ 35.98	41	15.0%	$ 5.41	$ 38.39	6.7%	$ 2.41	$ 36.19	0.6%	$ 0.21
500	$ 43.35	49	12.6%	$ 5.46	$ 46.36	6.9%	$ 3.01	$ 43.61	0.6%	$ 0.26
600	$ 50.72	56	10.9%	$ 5.51	$ 54.33	7.1%	$ 3.61	$ 51.03	0.6%	$ 0.31
700	$ 56.74	62	9.7%	$ 5.51	$ 61.60	8.6%	$ 4.86	$ 57.67	1.6%	$ 0.93
800	$ 62.76	68	8.8%	$ 5.51	$ 68.87	9.7%	$ 6.11	$ 64.30	2.5%	$ 1.54
900	$ 68.78	74	8.0%	$ 5.51	$ 76.14	10.7%	$ 7.36	$ 70.94	3.1%	$ 2.16
1000	$ 74.80	80	7.4%	$ 5.51	$ 83.41	11.5%	$ 8.61	$ 77.58	3.7%	$ 2.78
1100	$ 80.82	86	6.8%	$ 5.51	$ 90.69	12.2%	$ 9.86	$ 84.22	4.2%	$ 3.39
1200	$ 86.84	92	6.3%	$ 5.51	$ 97.96	12.8%	$ 11.11	$ 90.85	4.6%	$ 4.01
1300	$ 92.87	98	5.9%	$ 5.51	$ 105.23	13.3%	$ 12.36	$ 97.49	5.0%	$ 4.62
1400	$ 98.89	104	5.6%	$ 5.51	$ 112.50	13.8%	$ 13.61	$ 104.13	5.3%	$ 5.24
1500	$ 104.91	110	5.3%	$ 5.51	$ 119.77	14.2%	$ 14.86	$ 110.77	5.6%	$ 5.86
1600	$ 110.93	116	5.0%	$ 5.51	$ 127.04	14.5%	$ 16.11	$ 117.40	5.8%	$ 6.47
1700	$ 116.95	122	4.7%	$ 5.51	$ 134.31	14.8%	$ 17.36	$ 124.04	6.1%	$ 7.09
1800	$ 122.97	128	4.5%	$ 5.51	$ 141.59	15.1%	$ 18.61	$ 130.68	6.3%	$ 7.70
1900	$ 128.99	135	4.3%	$ 5.51	$ 148.86	15.4%	$ 19.86	$ 137.31	6.4%	$ 8.32
2000	$ 135.02	141	4.1%	$ 5.51	$ 156.13	15.6%	$ 21.11	$ 143.95	6.6%	$ 8.94
2500	$ 165.12	171	3.3%	$ 5.51	$ 192.49	16.6%	$ 27.36	$ 177.14	7.3%	$ 12.02
3000	$ 195.23	201	2.8%	$ 5.51	$ 228.84	17.2%	$ 33.61	$ 210.33	7.7%	$ 15.10
3500	$ 225.34	231	2.4%	$ 5.51	$ 265.20	17.7%	$ 39.86	$ 243.51	8.1%	$ 18.18
4000	$ 255.44	261	2.2%	$ 5.51	$ 301.56	18.1%	$ 46.11	$ 276.70	8.3%	$ 21.26
4500	$ 285.55	291	1.9%	$ 5.51	$ 337.91	18.3%	$ 52.36	$ 309.89	8.5%	$ 24.34
5000	$ 315.66	321	1.7%	$ 5.51	$ 374.27	18.6%	$ 58.61	$ 343.07	8.7%	$ 27.42

Note: Rate impacts include not only base rates but ECR and EECR rates from Schedule H.

The rate design proposed above would encourage the efficient use of energy, reduce the promotion of electric heat, and would have less undue bill impacts than OG&E's proposal. The Commission should adopt it.

Q. Does this complete your testimony, Mr. Marcus?

A. Yes, it does. Thank you.

CERTIFICATE OF SERVICE

I, Sarah R. Tacker, do hereby certify that on this 13th day of January, 2009, a copy of the above and foregoing Direct Testimony was emailed to the following persons at the indicated email address:

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